ENERGY TECHNOLOGY AND GOVERNANCE PROGRAM

Assessment and Training on the Impacts of Large-Scale RES and Gas Integration in SEE

– Draft Report –

ELECTRICITY MARKET INITIATIVE WORKING GROUP

This report made possible by the support of the American people through the United States Agency for International Development (USAID). The contents are the responsibility of the United States Energy Association and do not necessarily reflect the views of USAID or the United States Government.

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October 16, 2020

ELECTRICITY MARKET INITIATIVE WORKING GROUP

Cooperative Agreement AID-OAA-A-12-00036

Prepared for:

United States Agency for International Development
and
United States Energy Association

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ACKNOWLEDGMENTS

The authors of this Study would like to thank all EMI members who contributed to the preparation of this report, as well as USAID for financial support for this Study and the entire EMI Project.

CONTENTS

ABBREVIATIONS

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

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 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 current 15 participating companies in this program. With this level of participation, the EMI is one of the region's most comprehensive power system projects.

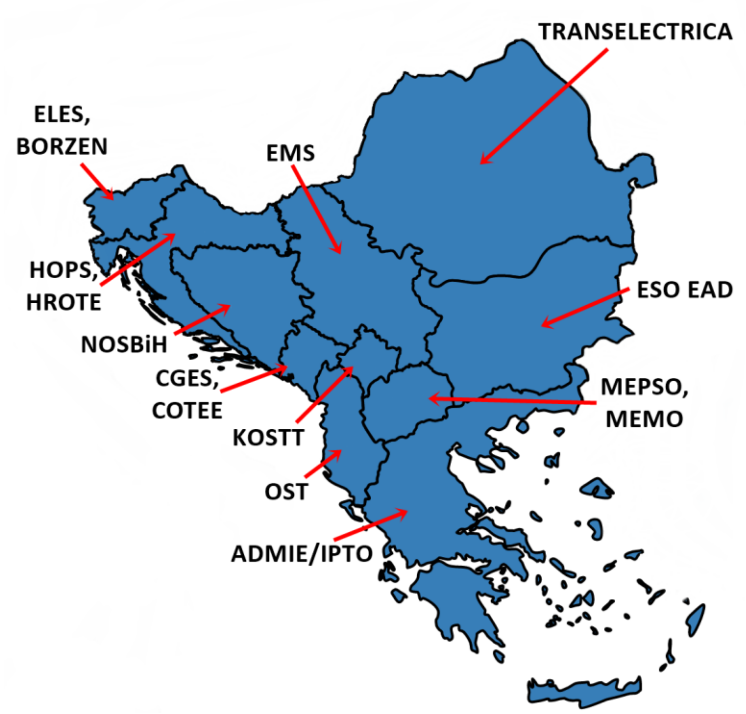


Figure 1: EMI participants

The newly adopted EU Energy Law (the "Clean Energy for all Europeans") package has set 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, especially those in the Western Balkans (WB6). Some of them are from EU member states (Slovenia, Croatia, Bulgaria, Romania and Greece), 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.

In addition, new gas generation is likely to replace some of the 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, and other sources.

This is the first regional study to combine detailed market and network analysis in level of detail sufficient to support the both market integration and network upgrades both on the regional and internal country level. Thus, this EMI work will promote the integration of electricity markets region-wide, in concert with the MOU that all EMI members have signed, and it will identify opportunities to transfer RES and gas-fired generation 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 and regulators to deal with those impacts, including:
    - preparations to accommodate coupling
    - regulations and rates to facilitate internal and cross-border integration
3. To reflect the challenges of RES and 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

The results of this Study provides these expected benefits for the EMI members:

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 impact of large-scale RES development in the neighboring countries on their internal networks.

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

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

This Draft Report consists of 8 chapters on 344 pages, including 297 figures and 197 tables. It provides detailed overview of 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 South East European power system foreseen in 2030 with different levels of RES integration.

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 TYNDP, MAF 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, Ukrainian's and Moldovan'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
- Must-run constraints 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).

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 hydrological conditions: average and dry

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

- 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 Referent and Low demand scenario

- 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 source of the data were 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 taking special care to maintain the consistency of the input dataset. Thus, the data mainly originated from the ENTSO-E Ten-Year Network Development Plan (TYNDP) and Mid-Term Adequacy Forecast (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 model 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; NTCs and neighboring power systems.

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 data, or as a backup, we added 25% to the RES capacities in the referent 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 hydrological 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).

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 hydrological 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. On the other side, it is expected that in 2030 Ukraine and Moldova will be synchronously connected with ENTSO-E, and with respect to that, Ukrainean and Moldovan power systems have been modeled as well.

Hungarian, Ukrainian and Moldovan power systems have been modeled with expected demand/supply scenarios (based on TYNDP2020 National Trends for HU & BAU scenarios for UA and MD), but with two levels of CO_2 prices in line with 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 units 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 the ENTSO-e. NTC values for every border are determined by the TSOs on both sides of the border and mutually harmonized. Harmonized and consolidated NTC values that have been implemented in our study are given in the following table (Table 5).

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

The Antares model included power systems of all EMI WG members and the neighboring markets, 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 will be 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 using 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.

The details for each market zone (EMI member) have been given in the Interim Report while here we present several tables with overview of the expected development of consumption and generation per different technologies in the whole SEE.

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**

Clearly, we expect **total regional demand growth in the period of 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 is in the range 0.18% (HR) – 2.79% (ME). In the low demand growth scenario, annual growth rates per market area are in the range of 0.09% (HR) – 1.96% (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, the markets **in SEE expect a significant increase in wind power capacity in the coming decade, in the range of 11833 – 16269 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 (4698 MW (referent scenarios) to 6498 MW (high RES scenario), while in relative terms, the largest growth is anticipated in RS (2691 MW in the referent scenario), or 14.4 times more WPP capacity in 2030 than in 2018, and 3414 MW in the high RES scenario, or 18 times more 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 11014 – 17234 MW (referent vs high RES scenario) of SPP in the region, or 3.14 – 4.34 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 – 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.

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. On the level of the entire EMI region, total increase in installed HPP capacity will be significant. In absolute terms **4960 MW of new HPP is expected by 2030, which is a growth of 20%** 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 1905 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.

However, for the entire EMI region, the **total decrease in installed TPP capacity will be significant, around 3000 MW, but it is just 8% 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.

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. Total installed generation capacities in SEE in 2030 is expected in the range 97 878 – 108 534 MW. In other words, High RES scenario assumes 10 656 MW of additional installed generation capacities in SEE or about additional 10% compared to Referent RES scenario, as shown in the following table.

Status of the installed capacities in SEE in 2018 is presented in Table 11 and Table 12.

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. **Total installed capacities will increase for 30% or for more than 24 GW**, with decrease in TPPs and increase in all other technologies. The main change is expected in RES capacities. Wind and solar capacities will increase 3 or 4 times (with respect to referent or high RES scenario in 2030) while capacities in HPPs (mainly small HPPs) will increase for 20%. This change in the technological structure of the power systems will cause significant changes in system operation and will present a challenge for system operators.

However, dominant installed generation capacity will remain in TPPs: 36.1% in Referent RES scenario and 32.6% in 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 Referent RES scenario and 29.9% in High RES scenario. From 2018 to 2030, share in HPPs will decrease for 3% but share of TPPs will decrease for almost 20%. Share of wind and solar capacities will increase from 14% to 33% or 40%, depending on the aggressiveness of the RES development, and this present the main change in the next 10 years.

WPP installed capacity shares in SEE is in the range: 18.5% in Referent RES scenario and 20.8% in 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 is in the range: 15.4% in Referent RES scenario and 19.6% in High RES scenario. The highest SPP shares are found, as expected, on the south of the region: in GR (28.4 - 31.1%), MK (16.7 – 21.0%) and BG (21.3 – 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 the EMI's work. The EMI analysis assessed the extent to which various power plants and types of plants will be utilized in a regional market, in which all the existing and new capacity competes to meet customer demand for energy (kWh) on a hourly 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 figure with detailed explanation of all parts of data.

3.1.1. Area summary report

Area summary report is used for showing summary data for each of selected areas. Figure 2The following figure shows example of area summary report, with detailed description of data columns shown in such report.

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

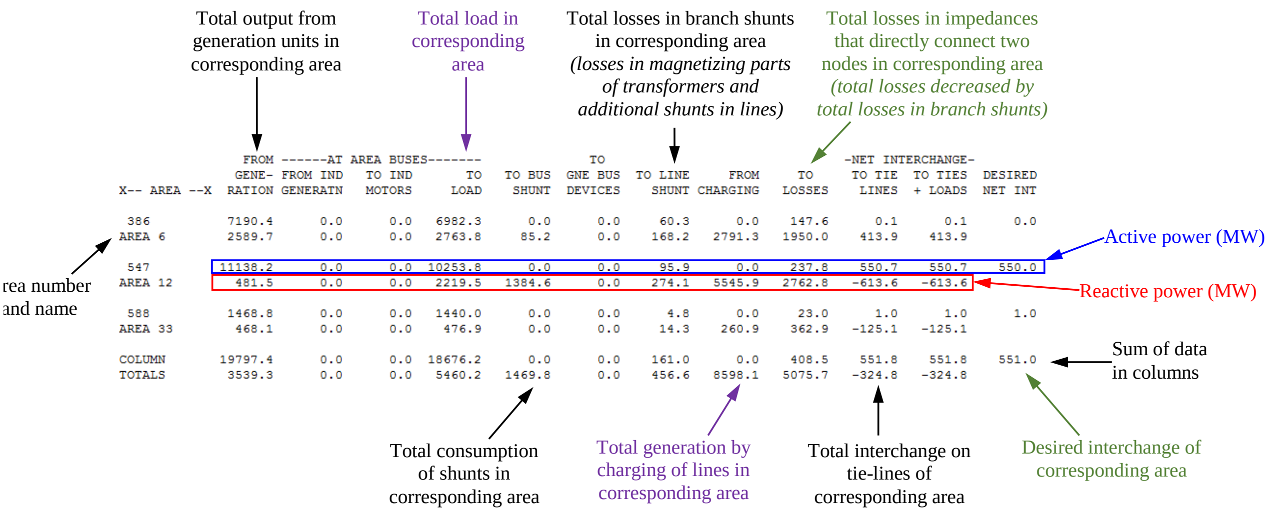


Figure 2: Description of data shown in area summary report from PSS®E

3.1.2. Subsystem summary (summary per voltage levels)

Example of subsystem summary (summary for selected part of system) is shown 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 per each voltage level which exists in selected subsystem. In this part data related to column "TO LOSSES", "TO LINE SHUNTS" and "FROM CHARGINGS" are distributed per each voltage level.

Since lines are elements which connect nodes of the same voltage level, it is clear how lines are assigned to voltage levels. The other story is related to transformers, so it is question how transformers are assigned to voltage level.

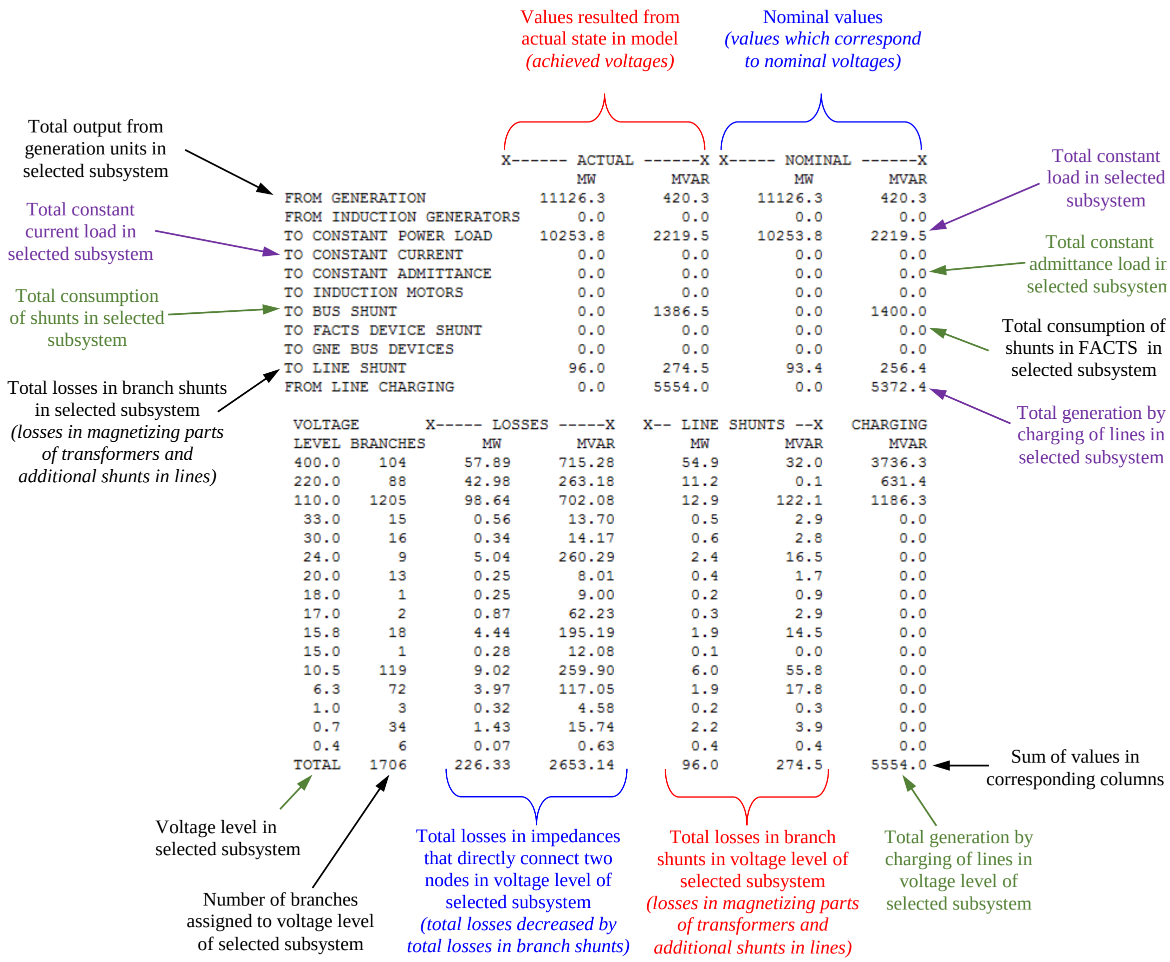


Figure 3: Description of data shown in subsystem summary report from PSS®E

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

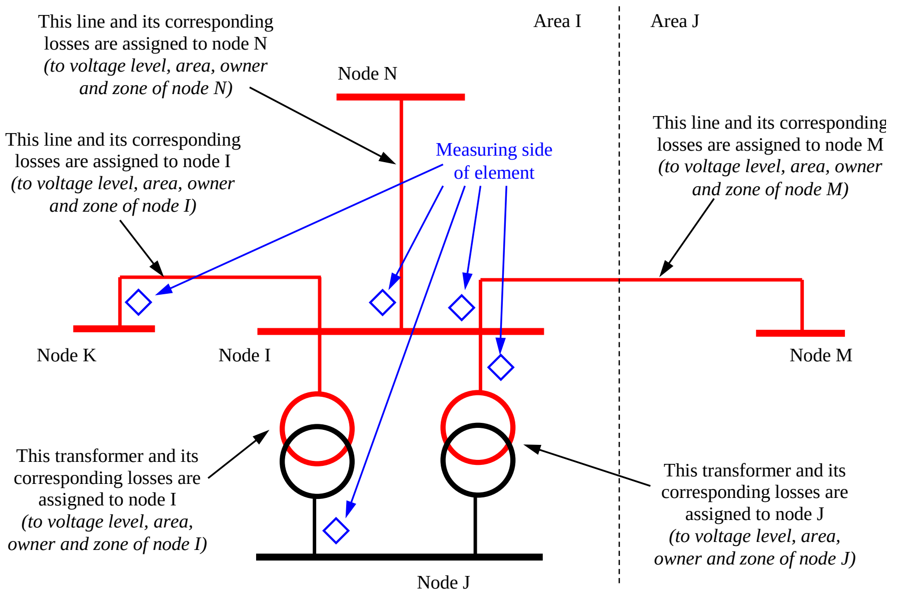


Figure 4: Description of rules for assignment branches to voltage levels

3.1.3. Contingency analysis report

Example of report from contingency analysis is shown in Figure 5. This report contains four main parts.

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

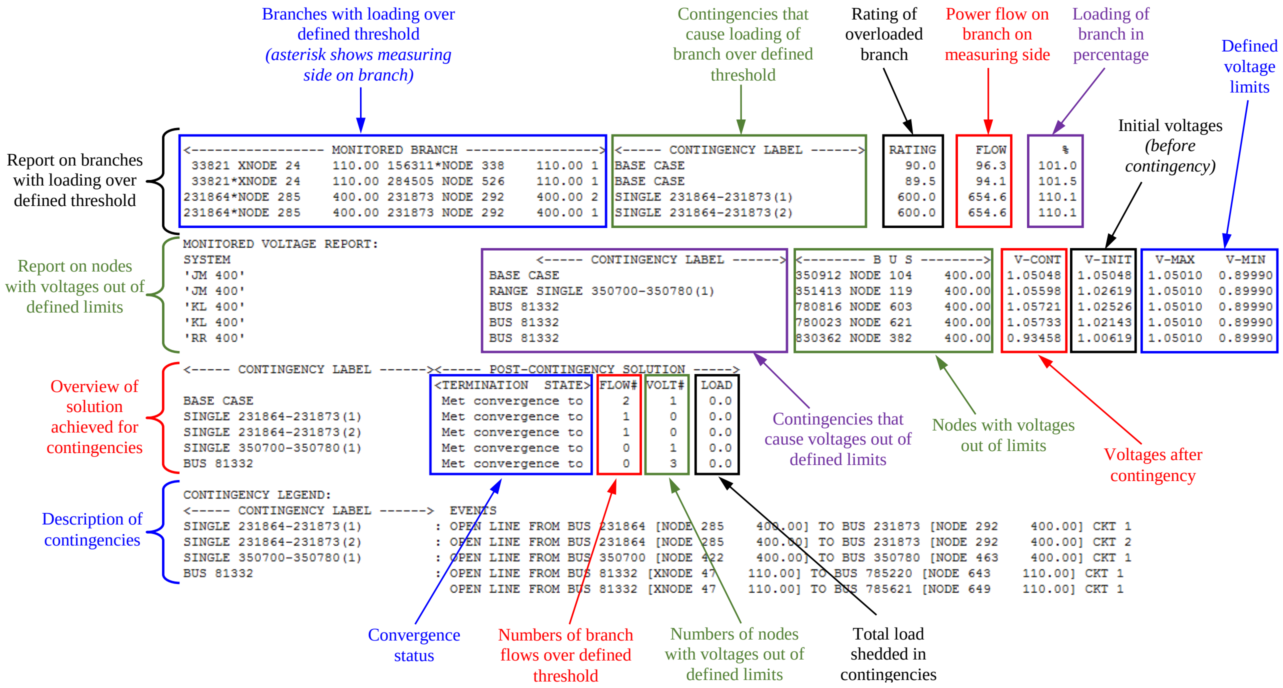


Figure 5: Description of data shown in report from contingency analysis, in format of PSS®E report

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

The second part shows monitored nodes with voltages out of defined limits. For better understanding, voltage limits for each node are shown within these data.

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

Finally, the fourth part provides 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, 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, it was necessary to collect individual models from all participating TSOs, and merge them into a single regional one.

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

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

The third step is 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 will use the adjusted regional models for detailed AC load flow simulations. This will be based on the generation dispatch we obtain from the market simulation scenarios with different levels of RES, different hydrological conditions, and different 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.

Beside summary per each area and analysis of voltage profile, for each regional model, assessment of steady-state security against single outages has been made. This assessment included analyses of grid conditions in case of single outage of branches with regional importance. Following branches have been included in list of outages as well as in list of monitoring elements:

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

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

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

In the Interim Report detailed output on power system balance, network losses, voltage profile and n-1 contingency analysis is checked for the base cases is given. It proved that the basic models are reliable and convenient for the 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	AT AREA BUSES: FROM IND GENERATN	AT AREA BUSES: TO IND MOTORS	AT AREA BUSES: 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	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 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.

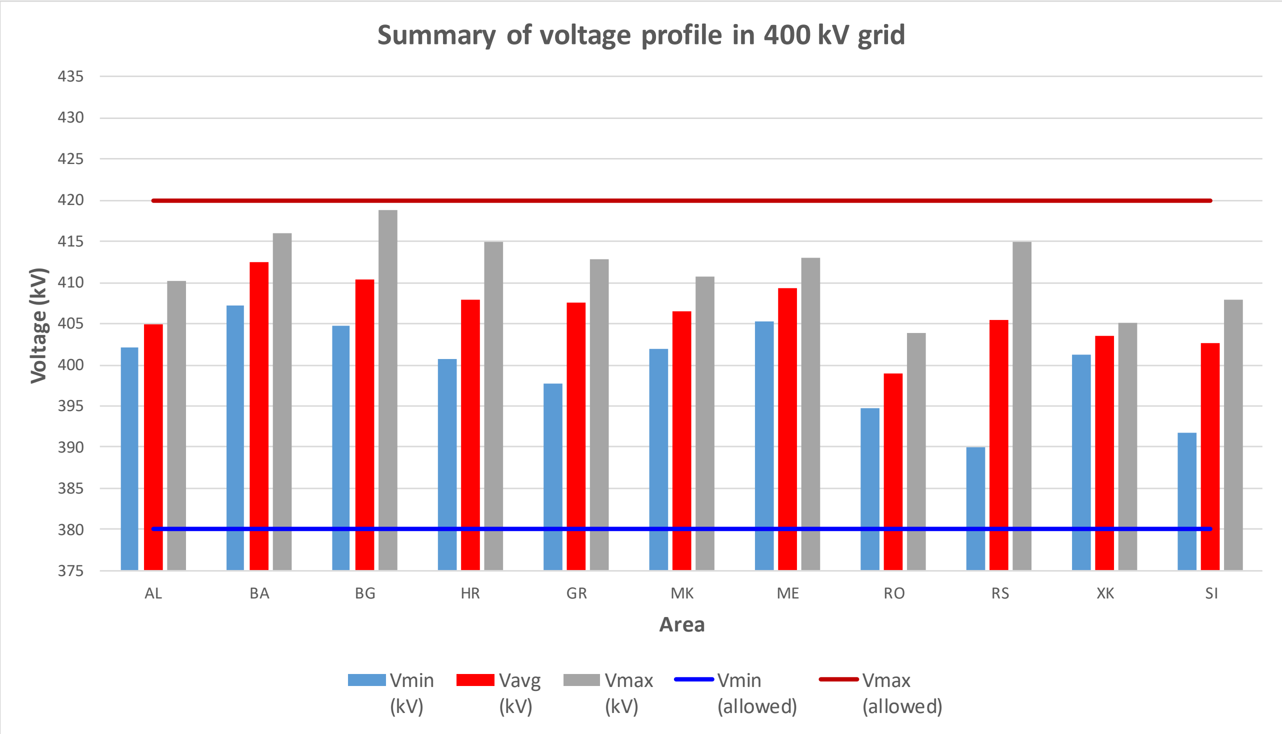


Figure 6: Summary of the voltage profile in the 400 kV grid – maximum load 2030, referent RES

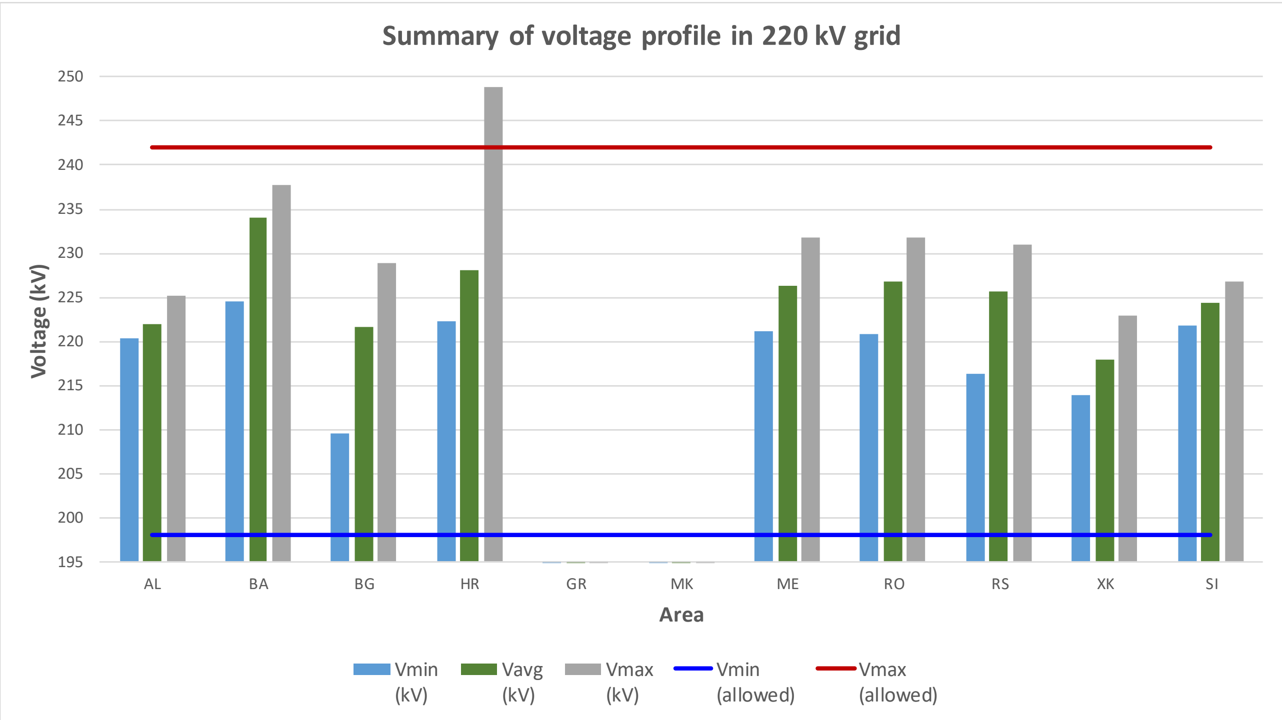


Figure 7: Summary of voltage profile in 220 kV grid – maximum load 2030, referent RES

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 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 maximum load regime, referent RES, are shown in Figure 8.

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

Aggregated border exchanges are shown in arrows. Direction of arrows is fixed and values inside can be positive and negative. Negative value means that aggregated border active power flow has opposite direction then the arrow shows. Bellow 2-character ISO code for each area/country there is TSO balance, which represent total import/export as sum of all aggregated border power flows from corresponding TSO.

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

3.2.2. Maximum load regime – high RES

We provided a summary of 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	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 summarized 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 numbers 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.

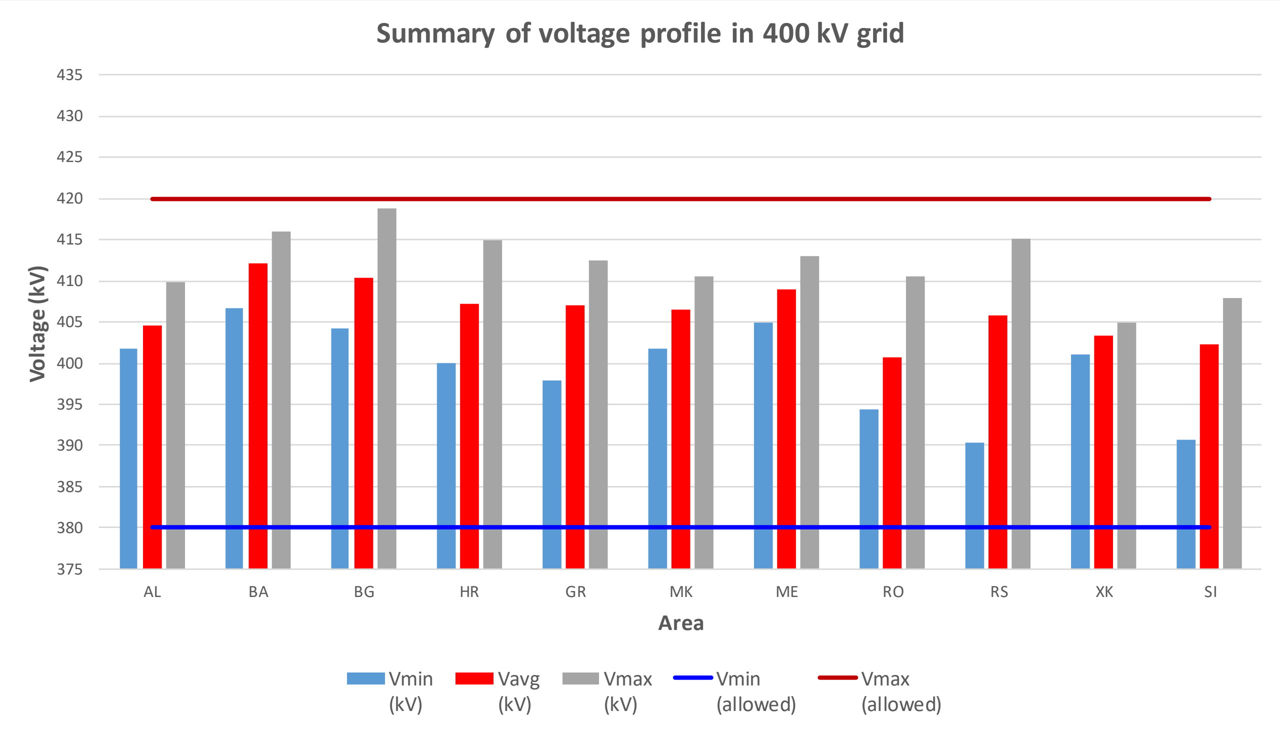


Figure 9: Summary of voltage profile in 400 kV grid – maximum load 2030, high RES

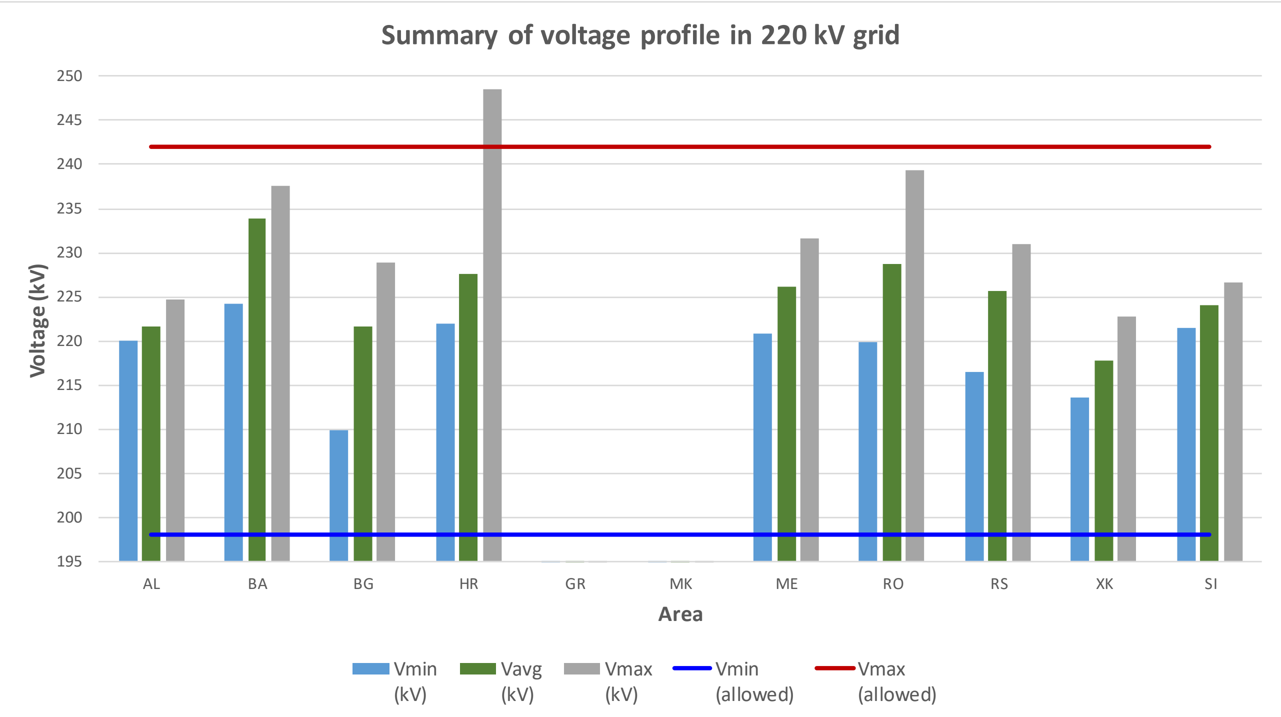


Figure 10: Summary of voltage profile in 220 kV grid – maximum load 2030, high RES

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

Aggregated border exchanges are shown in arrows. Negative value means that aggregated border active power flow has opposite direction then the arrow shows. Bellow 2-character ISO code for each area/country there is TSO balance, which represent total import/export as sum of all aggregated border power flows from corresponding TSO.

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 BUSES------- FROM IND GENERATN	TO IND MOTORS	TO LOAD	TO BUS SHUNT	TO GNE BUS DEVICES	TO LINE SHUNT	FROM CHARGING	TO LOSSES	-NET INTERCHANGE- TO TIE LINES	TO TIES + LOADS	DESIRED NET INT
10	702.4	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 corresponding data from the national/TSO models, 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 provided 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 400 kV as well as 220 kV (if exists). 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.

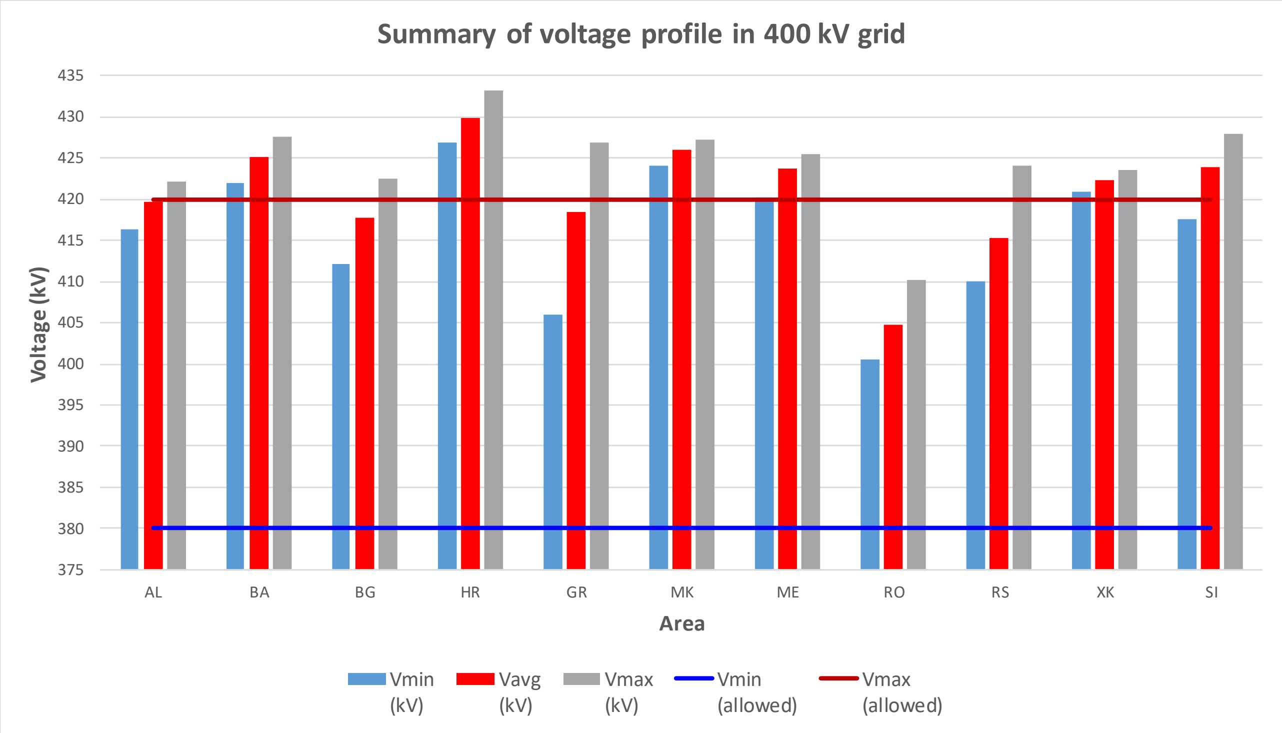


Figure 12: Summary of voltage profile in 400 kV grid – minimum load 2030, referent RES

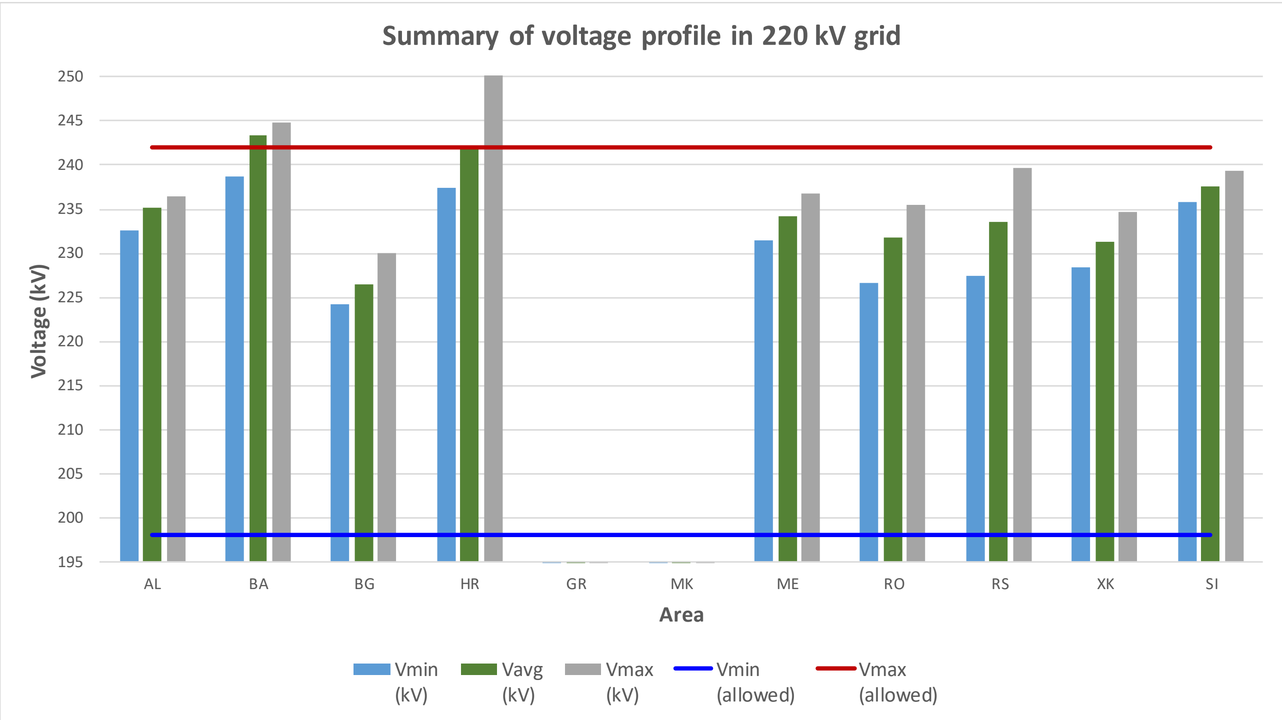


Figure 13: Summary of voltage profile in 220 kV grid – minimum load 2030, referent RES

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 average values are above the allowed maximum limit.

Situation is a 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.

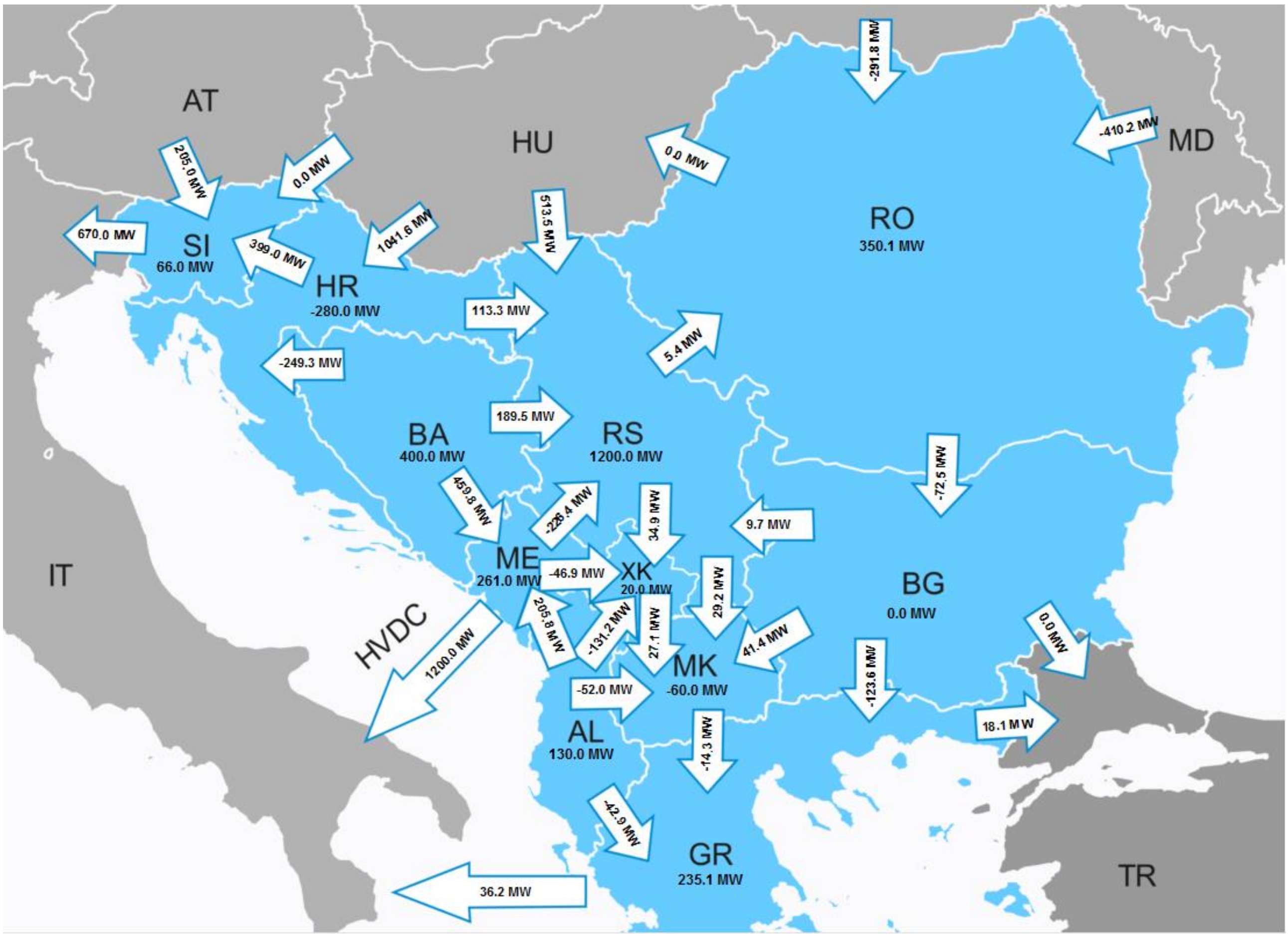


Figure 14: Aggregated border exchanges – minimum load 2030, referent RES

Aggregated border exchanges are shown in arrows. Negative value means that aggregated border active power flow has opposite direction then the arrow shows. Bellow 2-character ISO code for each area/country there is TSO balance, which represent total import/export as sum of all aggregated border power flows from corresponding TSO.

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 corresponding data from the national/TSO models, 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 400 kV as well as 220 kV (if exists). 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.

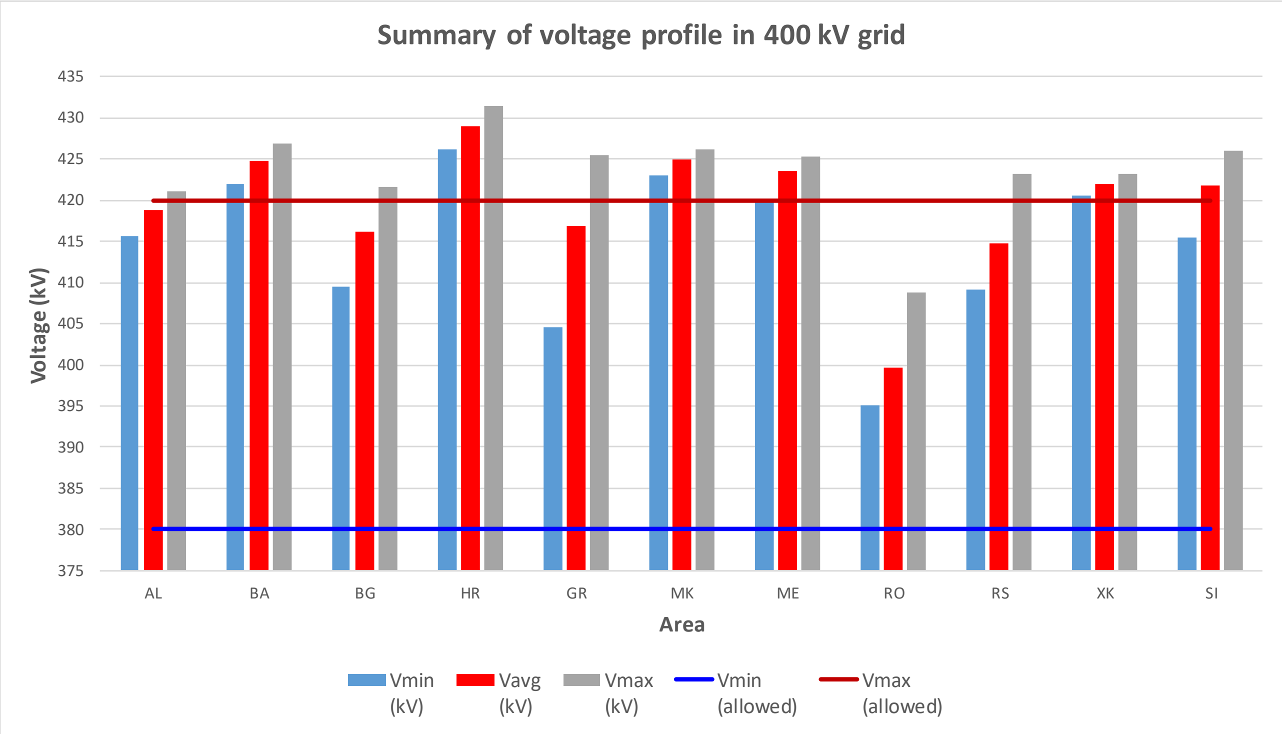


Figure 15: Summary of voltage profile in 400 kV grid – minimum load 2030, high RES

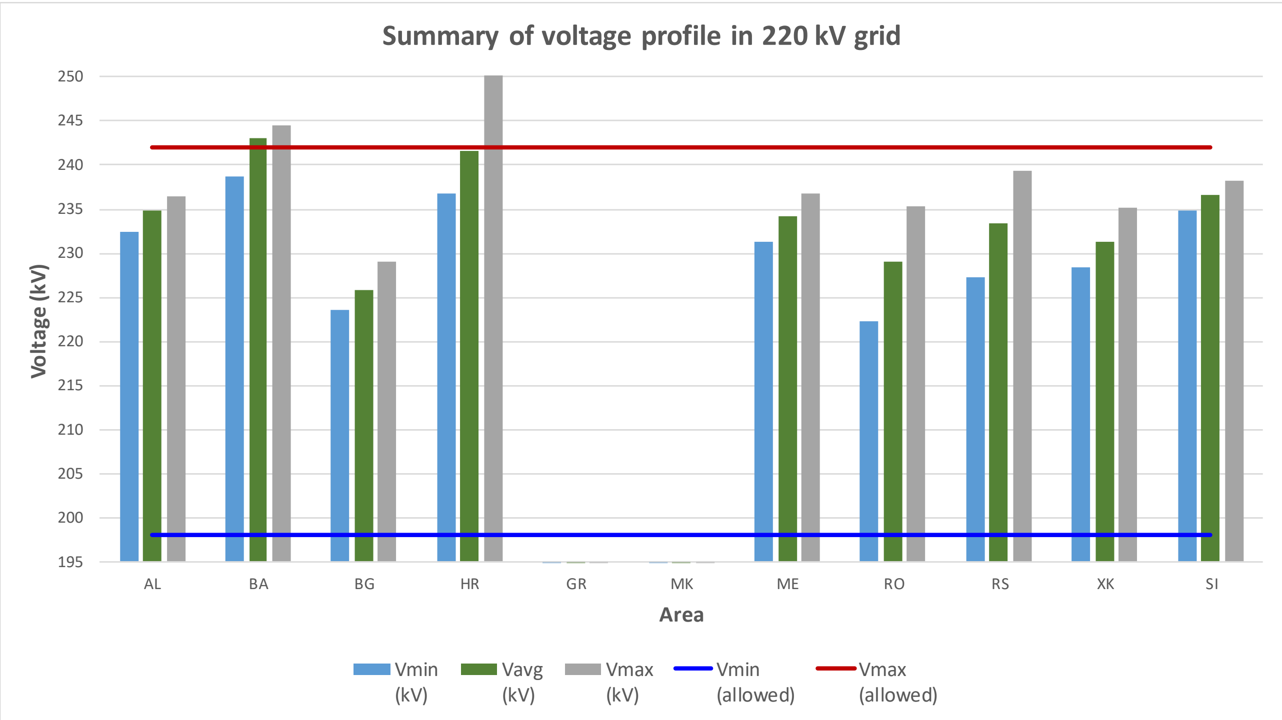


Figure 16: Summary of voltage profile in 220 kV grid – minimum load 2030, high RES

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 allowed maximum limit.

Situation is a 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

Aggregated border exchanges are shown in arrows. Negative value means that aggregated border active power flow has opposite direction then the arrow shows. Bellow 2-character ISO code for each area/country there is TSO balance, which represent total import/export as sum of all aggregated border power flows from corresponding TSO.

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
```

In can be seen that there is one outage, which causes overload. In case of outage of internal 400 kV line in Romania, Arad – Nadab, there is overload of around 2% of 400 kV internal line Gadalin – Rosiori and overload of around 10.9% of 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 simulations of electricity markets in SEE:

1. Electricity demand (both hourly load and total consumption);
2. Hydrological 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 is 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), hydrological conditions, fuel prices (gas, coal) and CO_2 emission prices. For each market area, and for the SEE region as a whole, we will model and analyze 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 larger scale RES integration, which may include 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 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 late 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 the analysis.

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

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 electricity generation mix by country and the region in 2030.
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 transfer 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 transfer 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 have 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 carefully 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 numerous, since we want to focus more on whether the impacts 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 hydrological conditions

Hydrological 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 hydrological conditions, along with different levels of CO_2 emission price and different demand levels. Our hydrological scenarios included the following:

- Average hydrological conditions; and
- Dry hydrological conditions.

The TSOs provide most inputs and assumptions on generation from HPPs in different hydrological 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 61 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 hydrological conditions.

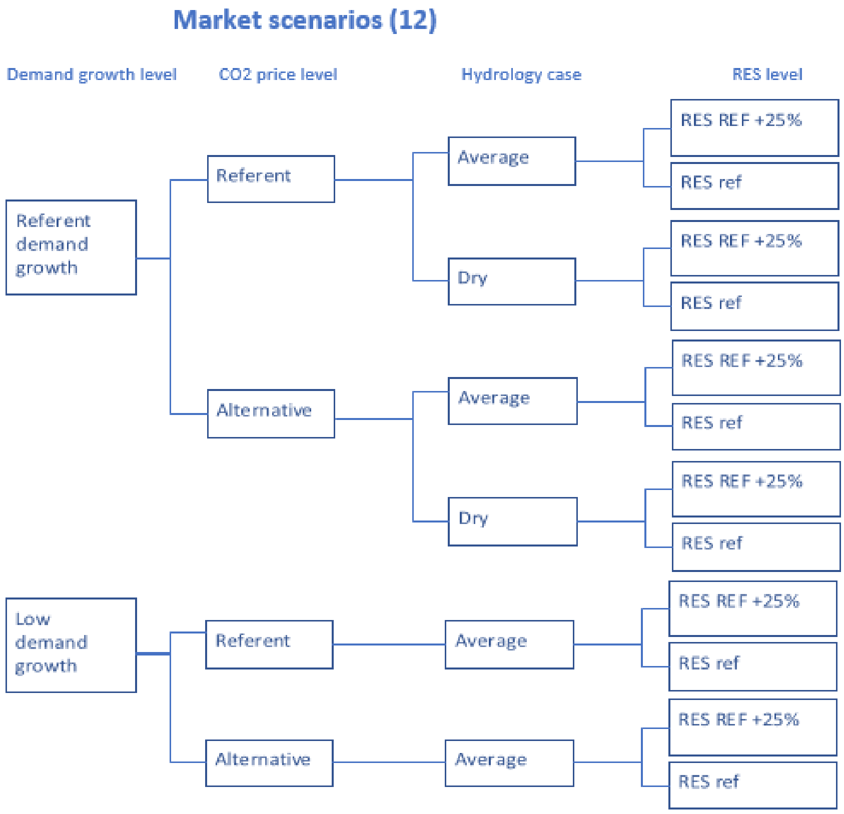


Figure 18: Set of scenarios with scenario-specific assumptions

Figure 60 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 need to add a set of scenarios related to network element availability. One set of network scenarios assume 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. In other words, 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 transmission network.

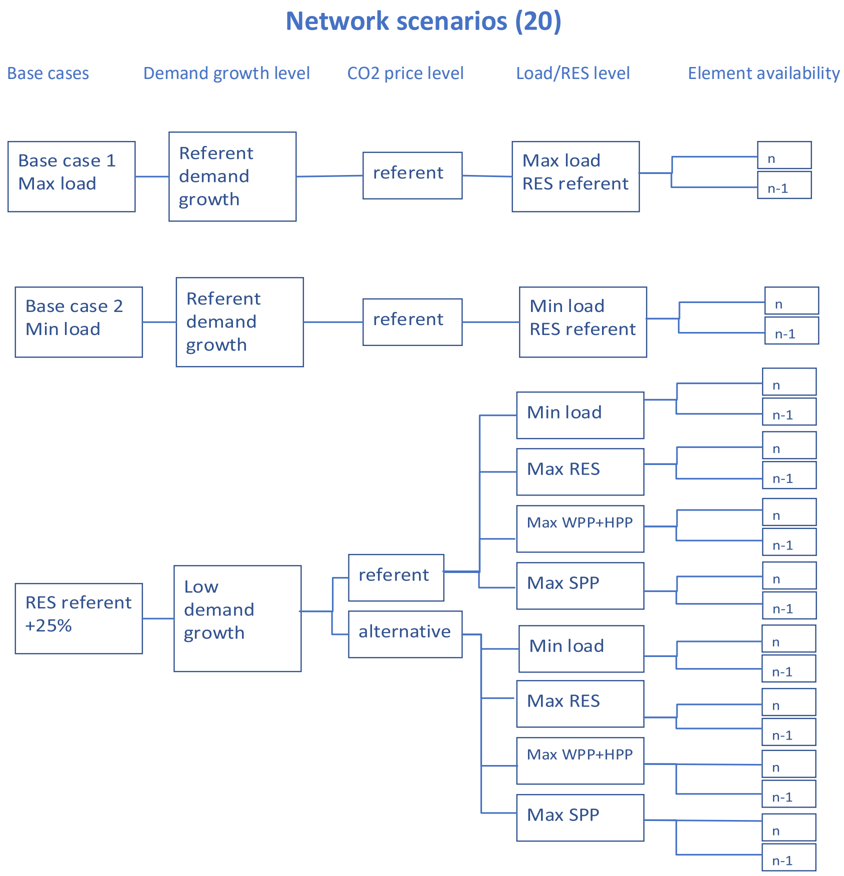


Figure 19: Set of network scenarios with scenario-specific assumptions for 2030

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, and later, trained 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 twelve market scenarios and twenty network scenarios. Every scenario provided 8 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 will give the EMI participants a clear picture of the impact on power flows, cross-border exchanges, voltage violations, network losses and bottlenecks, regionwide, and in each country. The EMI members will be able to 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. 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 is not to analyze natural gas projects, but rather to evaluate their potential impact on the regional market and network operation in large-scale RES integration environment. Therefore, we evaluated just one market and two network scenarios using new natural gas power plants here. The key assumptions related to operating conditions for these scenarios include:

- 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 hydrological conditions;
- Referent level of fuel prices (gas, coal); and
- Referent level of CO_2 emission price.

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

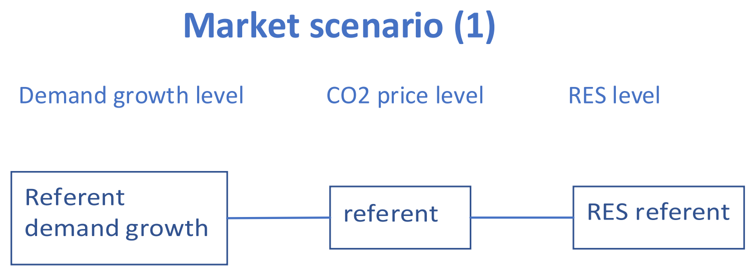


Figure 20: Electricity market scenario for natural gas impact

Again, this electricity market 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 execute 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 purpose, we needed just one of typical 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 the figure 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). 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 plan to run the n-1 contingency analysis only, as usual in all network planning studies.

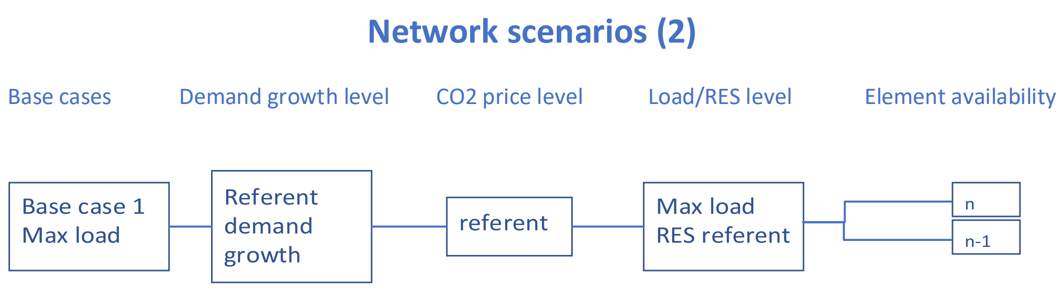


Figure 21: Transmission network scenario for natural gas impact

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 use these regional tools for the our analysis.

We will also provide these models and tools to the EMI members at the end of our analysis and we'll 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.

With the aim to be as clear as it is possible we grouped analysed 12 scenarios into 3 groups 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 referent and high CO_2 emission taxes**

In first two groups of scenarios, we analysed alternatives with referent and high RES capacities in two hydrological 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 hydrological conditions were assumed as avarege hydrology for all scenarios.

In the set of relevant market operation indicators, for each group of scenarios the following indicators are presented:

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 fuels powered plants: Sum of generation from lignite, coal and gas fired units
4. CO_2 emissions in Mt
5. Balance of the market area: Sum of the export and import of the zone
6. Wholesale market prices

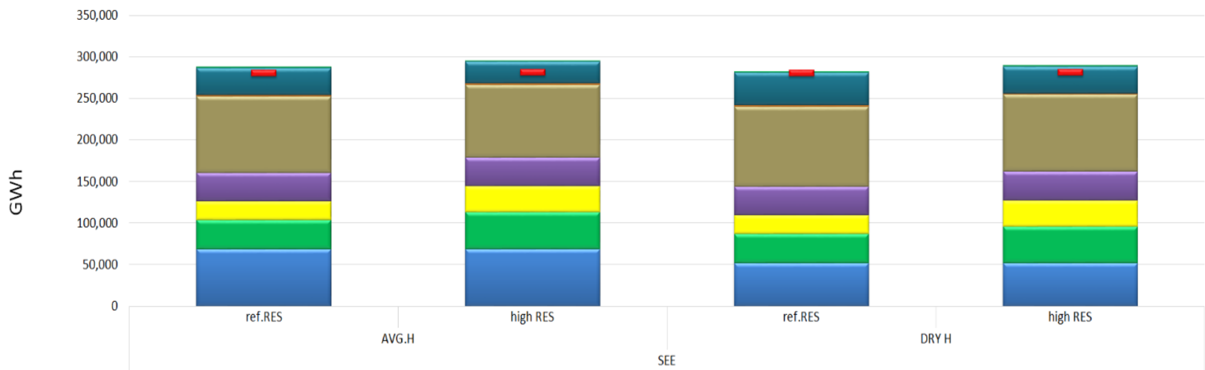
For each market area this set of relevant indicators is presented showing the level of impact that different development and operating alternatives can have on market in EMI region in 2030.

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

In the first group of scenarios, referent demand development and referent CO2 emission tax has been assumed and kept constant in 4 analysed scenarios that included:

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

Generation mix for the whole EMI region is presented in Figure 22 while main indicators are presented in Figure 23, pointing to the following:



	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

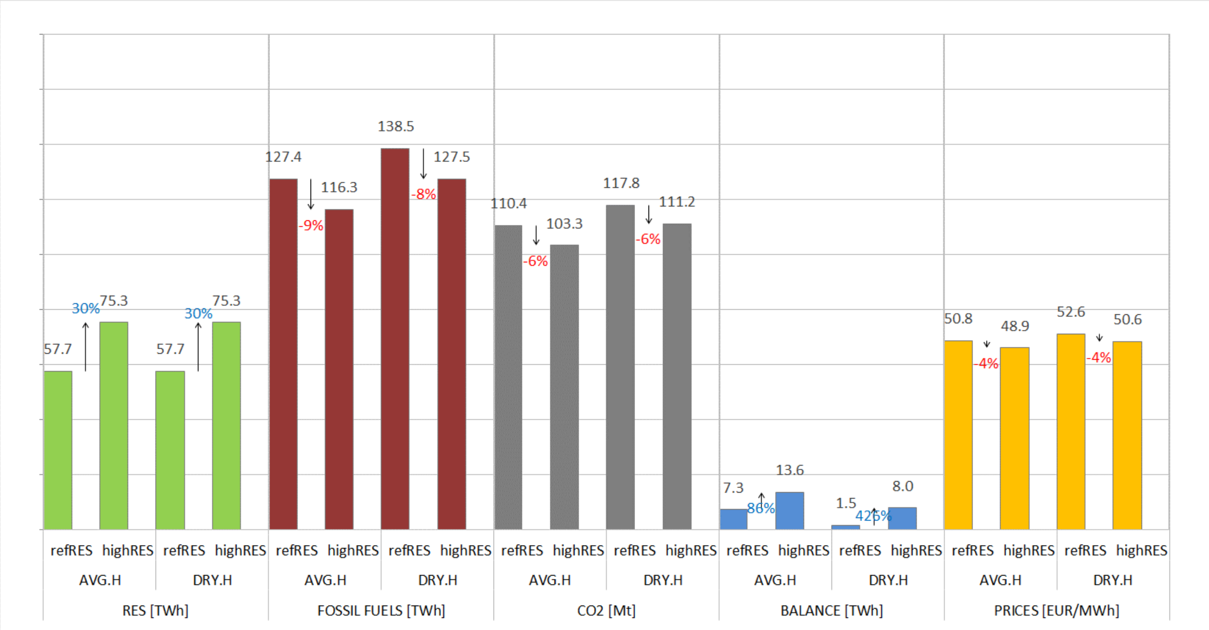


Figure 23: Main system operating indicators in EMI region in 2030 - ref. RES vs high RES, dry and average hydrology

- **Main technology in 2030 is still lignite and it supplies more than 33% of the load.**
- Hydro power plants supplies between 18% and 25%, depending on the hydrology, while RES generation (depending on the scenario) supplies between 21% and 27% of total demand. Separately considered, hydro and RES technologies become second main technologies in EMI region in 2030, but considered together as "green" technologies, hydro and RES generation become the main sources and supplies between 39% and 51% of total demand.
- Gas fired plants supply between 9% and 14 % of the total 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 high RES scenario which is the increase of 30% (Figure 23).** Increase per market areas (Figure 24) is between 0.2 and 6 TWh (in CGES and IPTO market areas) or between 19% and 278% (in HOPS and ELES market areas respectively).
- 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 powered plants generation is decreased: gas fired plants generation is decreased for 7 TWh, lignite fired plants for 4 TWh, and, export from the region is increased for 6 TWh.**

  The reason for this high decrease in generation from gas fired plants lies in the fact that in one of the biggest market areas in the region (IPTO) in 2030 only gas fired units exist. Due to this fact, 6 TWh increase in RES generation in this zone, provokes decrease in gas fired units generation for 5 TWh, which is almost equal to changes at the regional level. In all other market areas, decrease of fossil fuel fired plants generation, due to increased generation from RES, is almost equally divided between lignite and gas technologies (Figure 25).

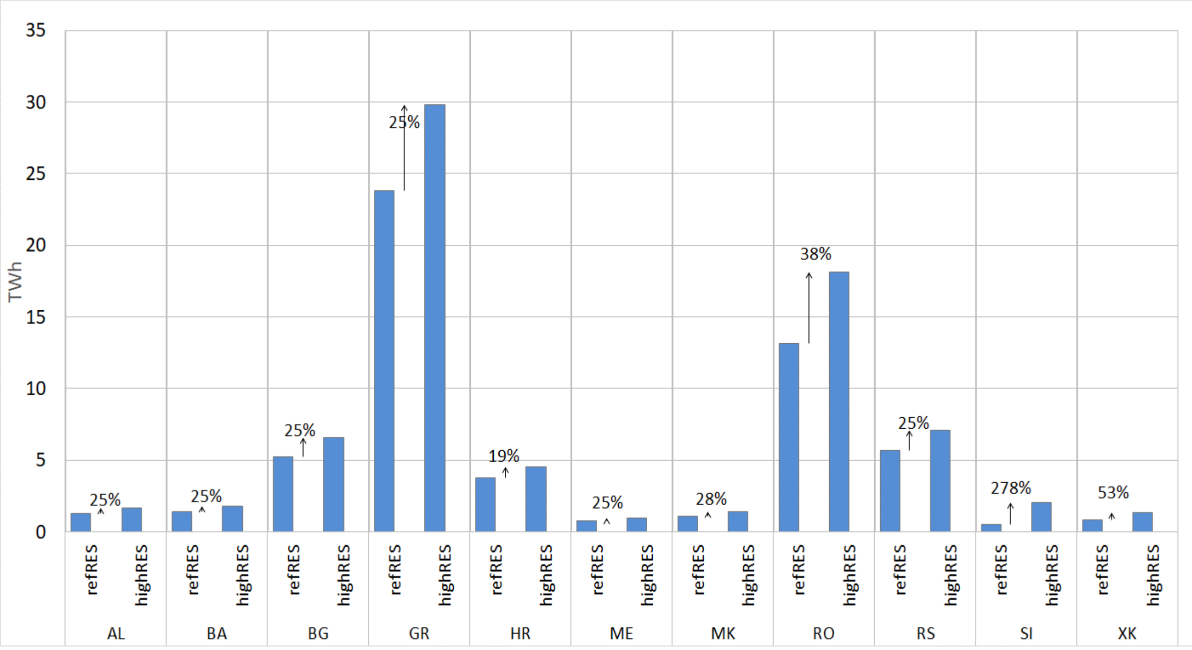


Figure 24: RES generation in 2030 - ref. RES vs high RES

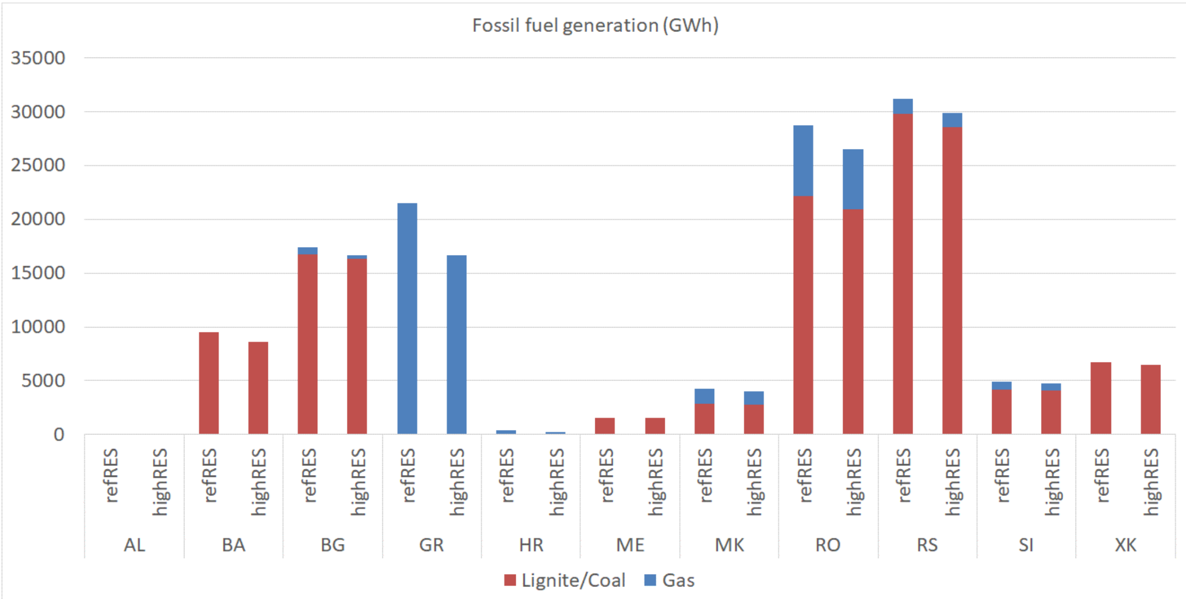


Figure 25: Fossil fuel powered plants generation in 2030 - ref. RES vs high RES, average hydrology

- **Following decrease in fossil fuels fired plants generation, CO_2 emission is decreased with high RES integration and this decrease is around 6% or 7 Mt of CO_2 for the whole EMI region.**
- **EMI region is a net exporter in 2030 in all scenarios with export between 1.5 TWh and 13.6 TWh or 1% and 5% of total demand.**
- Higher RES generation provokes decrease of TPPs generation but at the smaller level, and this leads to increase of the net export. Increase of export at regional level is around 6.5 TWh and is similar in both hydrological conditions (Figure 23). Changes in balance positions

for all market zones in average hydrological conditions (Figure 26) shows that in almost all countries, due to additional RES generation, export is increased or import is decreased. The only different behavior can be seen in NOSBIH market area where lignite fired plants become less competitive which leads to decrease of export.

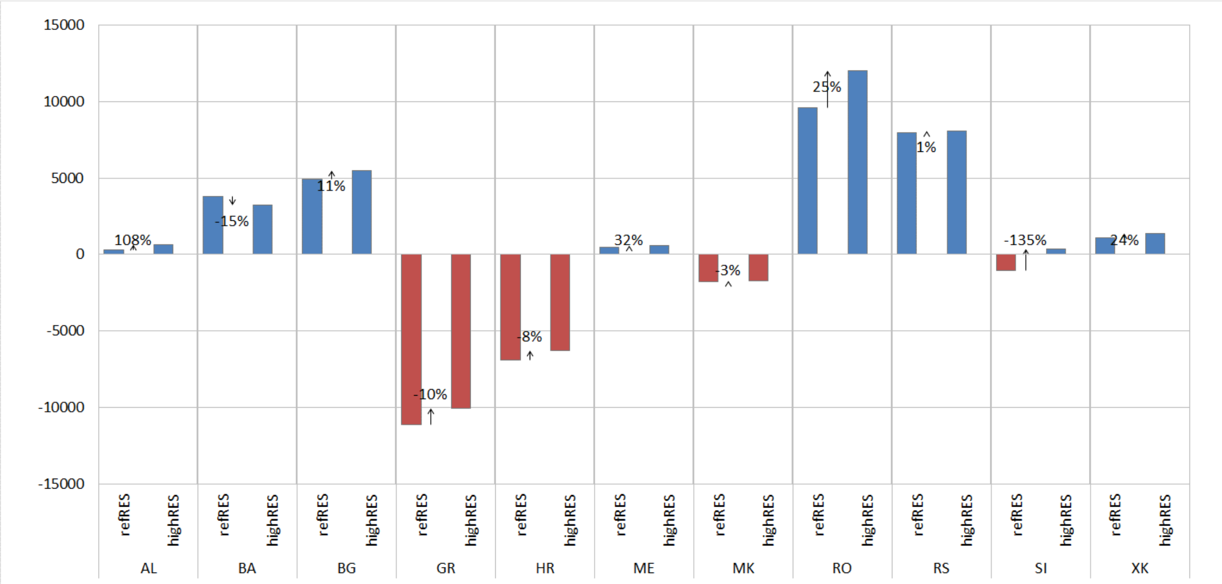


Figure 26: Balance positions per market areas in 2030 - ref. RES vs high RES, average hydrology

- **Average regional prices (Figure 23) are between 48.9 and 52.6 EUR/MWh with decrease provoked by high RES integration of around 2 EUR/MWh or 4% in both hydrological conditions.** From the same figure it could be seen that prices in dry hydrological conditions would be higher for around 1.7 EUR/MWh or 3.5%.

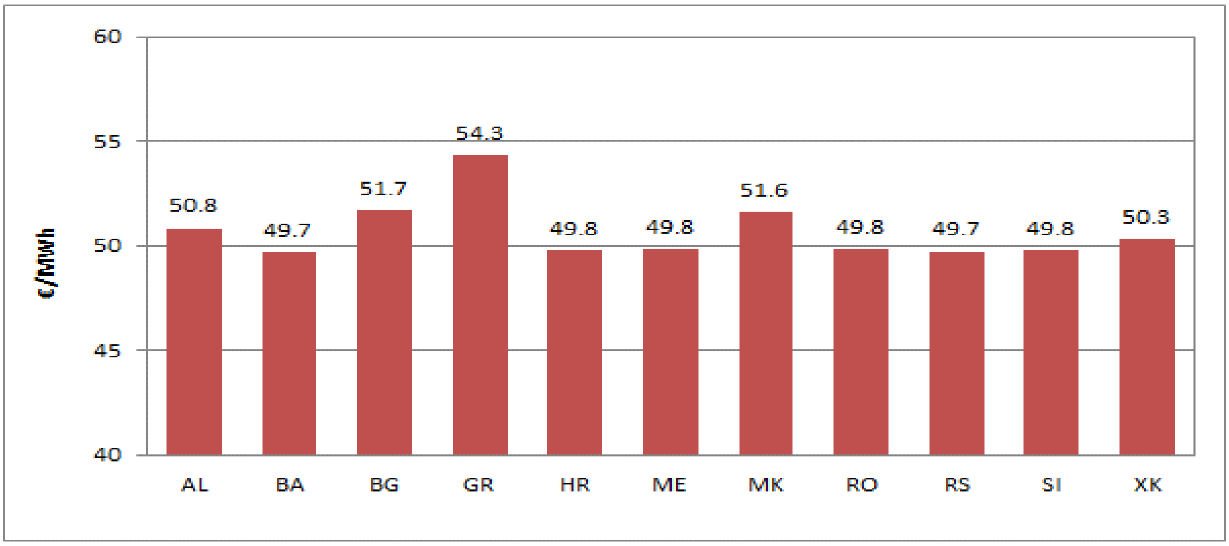


Figure 27: Prices in EMI region in 2030 - ref. RES, average hydrology

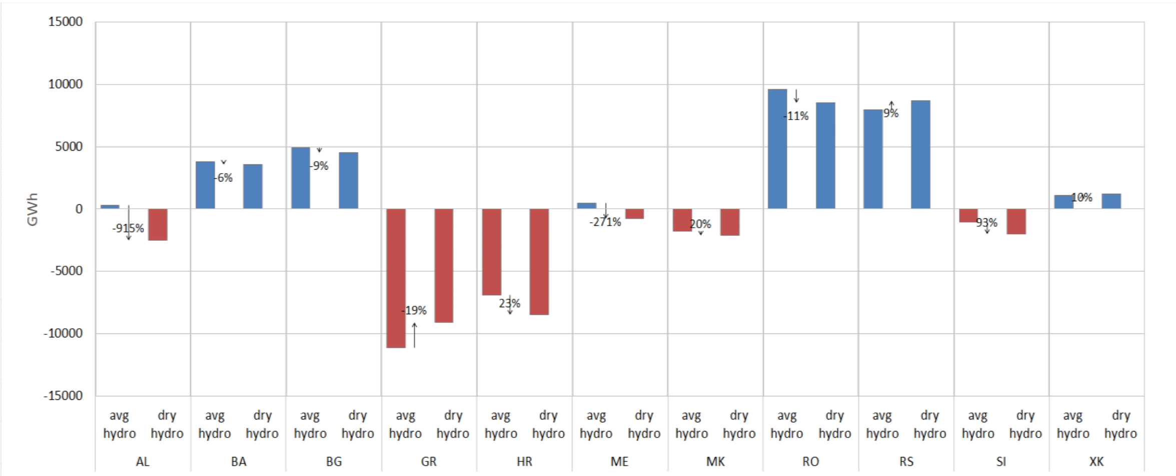
From Figure 27 it could be seen that there are 4 price zones in EMI region:

1) IPTO, 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 but between central zones and IPTO
4) All other zones

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

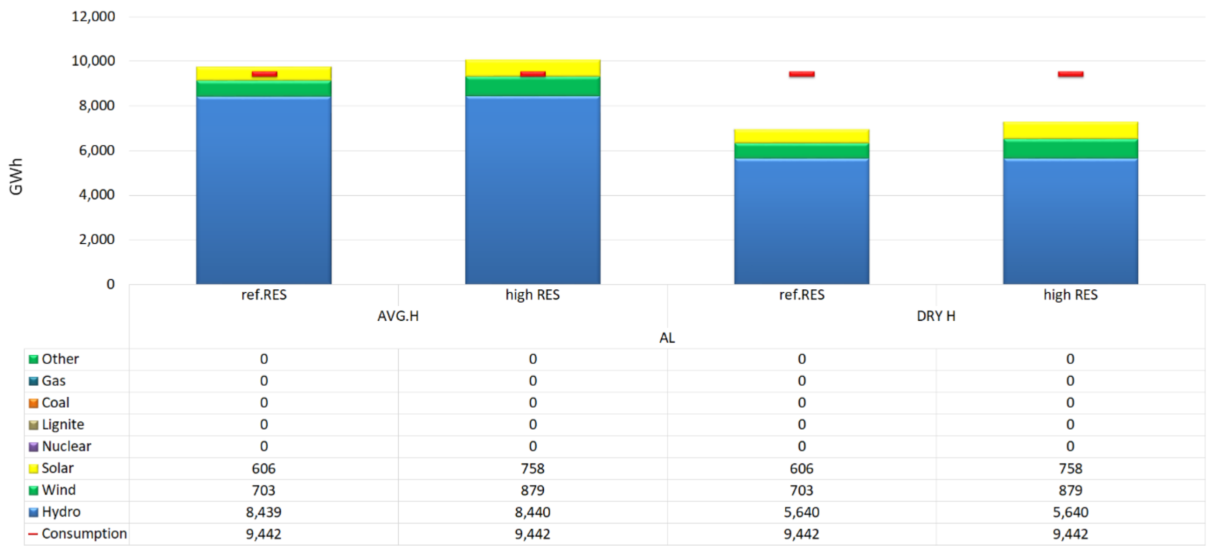
- Decrease of HPPs generation in dry hydrological conditions provokes higher TPPs generation that partially compensates the reduced HPPs generation while the other part of this reduction is compensated by the reduction in the regional export. These changes leads to increased prices, but change is rather small – 1.7 EUR/MWh at the regional level.
- Available energy in the whole EMI region in dry hydrological conditions is smaller, and 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 IPTO and EMS market areas where TPPs become more competitive enabling decrease of import (in IPTO) and increase of export (in EMS market area).



In the following chapters, detailed overview of the results per market areas are presented.

5.1.1. OST market area

Generation mix and selected set of indicators, as the main results of market analysis for OST market area, are presented in Figure 28 and Figure 29, respectively.



	AL AVG.H ref.RES	AL AVG.H high RES	AL DRY H ref.RES	AL DRY H high RES
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 28: Generation mix in OST market area in 2030 - ref. RES vs high RES, dry and average hydrology

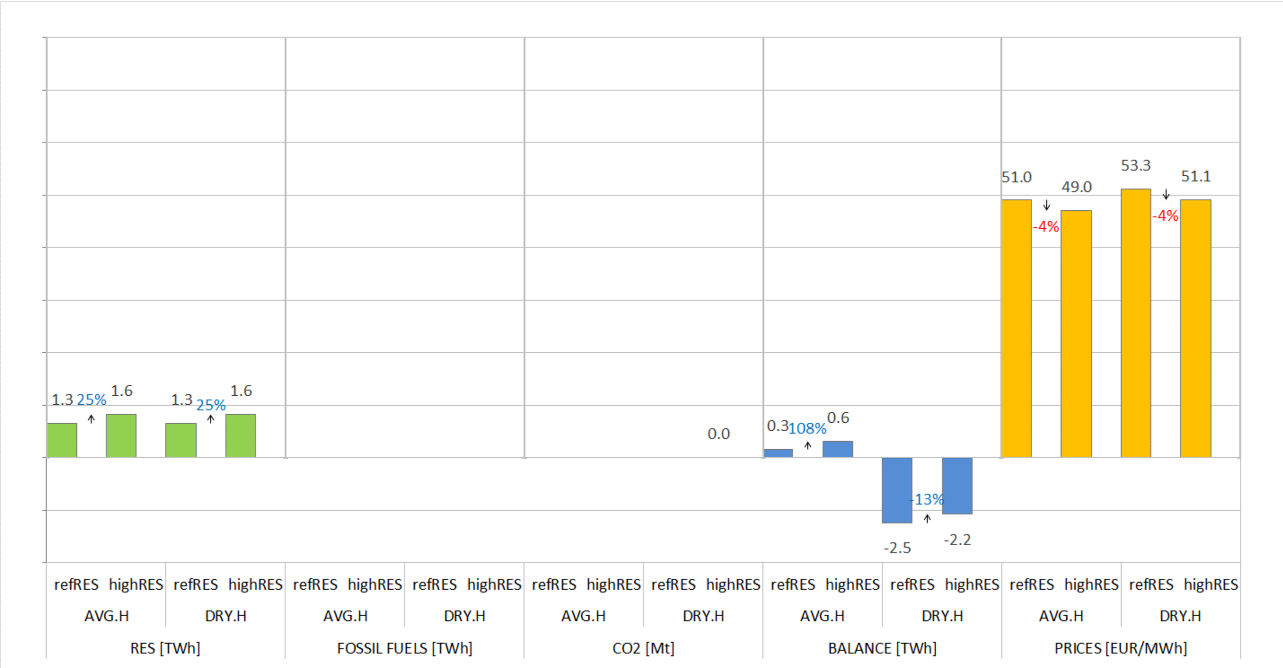


Figure 29: Main system operating indicators in OST market area in 2030 - ref. RES vs high RES, dry and average hydrology

Considering the generation mix presented in Figure 28, in conjunction with the main system indicators depicted in Figure 29, 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 hydrological conditions:

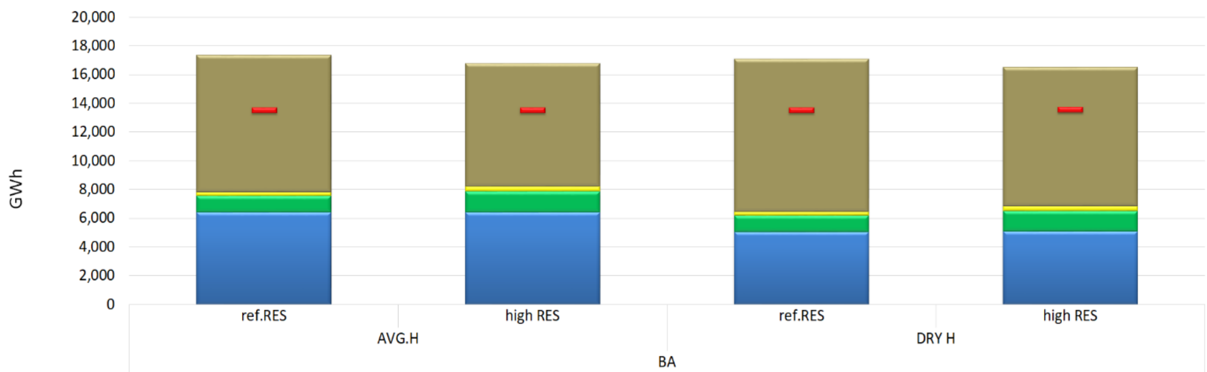
- RES generation is increased from 1.3 TWh in ref.RES scenario to 1.6 TWh in high RES scenario which is the increase of 25%. This increase is lower than the average increase in the EMI region (30%).
- RES generation supply between 14% and 17% of the area demand.
- Having in mind that OST market area is characterized with high hydro generation, its operation strongly depends on hydrological conditions. In average hydrological conditions

OST market area is balanced (with small net export), but in dry hydrological conditions, with hydro generation reduced for 2.8 TWh (33%), import is high (2.5 TWh), reaching 26% of total area demand.

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

5.1.2. NOSBIH market area

Generation mix and selected set of indicators, as the main results of market analysis for NOSBIH market area, are presented on 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 30: Generation mix in NOSBIH market area in 2030 - ref. RES vs high RES, dry and average hydrology

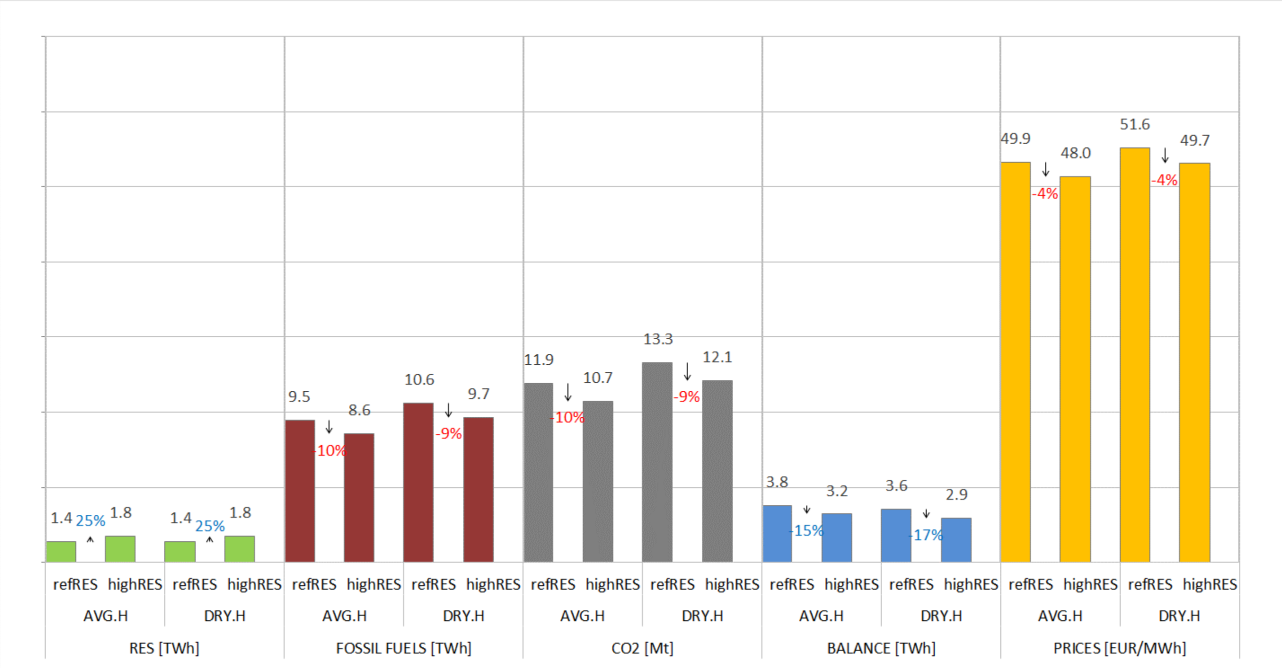


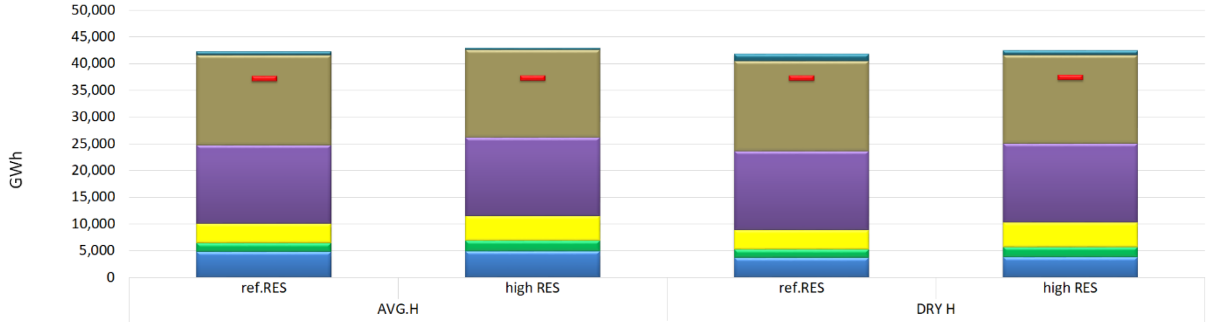
Figure 31: Main system operating indicators in NOSBIH market area in 2030 - ref. RES vs high RES, dry and average hydrology

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

- RES generation (wind+solar) rise from 1.4 TWh to 1.7 TWh (+25%) supplying 10%-13% of the area demand.
- Higher RES generation leads to reduction of generation from lignite fired plants for about 10% (-0.9 TWh) in both hydrological conditions. This decrease in TPPs generation leads to a decrease of CO2 emission for the same 10%.
- With small increase in RES generation (0.3 TWh) and reduction in TPPs generation (-0.9 TWh), NOSBIH market area decreases net export for around 0.6-0.7 TWh or 15% to 17% depending on the hydrology conditions. The reason for this lies in the fact that, with higher RES generation in NOSBIH market area but also in the whole EMI region, lignite fired plants from NOSBIH area become less competitive.
- On the other side, dry hydrological conditions moves regional merit order curve to the left and prices rise, which provides better position for lignite-fired plants in NOSBIH area. Hydro generation in dry hydrological conditions is reduced for 1.4 TWh or 22% in comparison to average hydrology, but net export is reduced for only 0.2-0.3 TWh. This means that in dry hydrological conditions that are critical for the whole EMI region, lignite fired plants from NOSBIH market area become more competitive than in average hydrological conditions.
- As a result, greater RES generation in both hydrological conditions leads to a decrease in prices for 4%. Namely, an increase in RES generation moves the merit order curve to the right and cheaper power plants become marginal.
- Simulations shows that engagement of PS HPP is very small pointing to the fact that existing hydropower plants and strong regional connections enables enough flexibility for the given level of RES generation.

5.1.3. ESO EAD market area

Generation mix and selected set of indicators, as the main results of market analysis for ESO EAD market area, are presented in Figure 32 and Figure 33, respectively.



	ref.RES (AVG.H)	high RES (AVG.H)	ref.RES (DRY H)	high RES (DRY H)
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 32: Generation mix in ESO EAD market area in 2030 - ref. RES vs high RES, dry and average hydrology

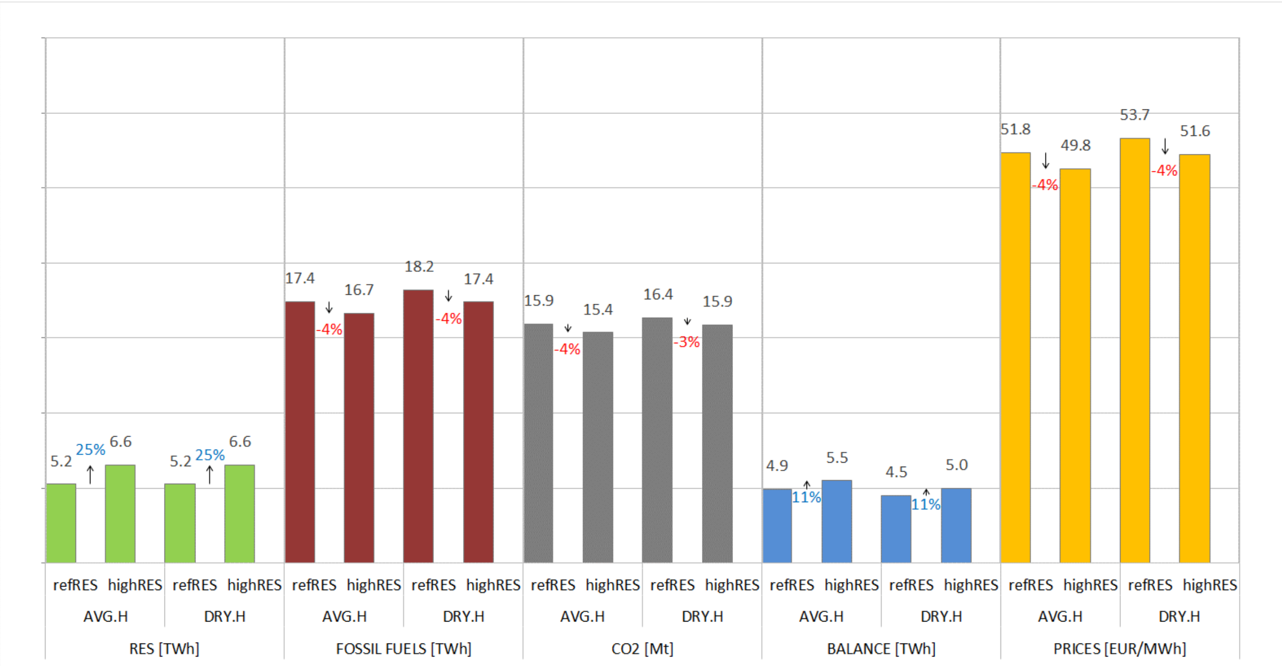


Figure 33: Main system operating indicators in ESO EAD market area in 2030 - ref. RES vs high RES, dry and average hydrology

Considering the generation mix presented above, in conjunction with the main system indicators depicted in Figure 33, 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 hydrological conditions:

- RES generation (wind+solar) rise 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 for about 4% (-0.7 TWh and -0.8 TWh) in both hydrological conditions. This decrease leads to a decrease of CO2 emission for 3-4%.
- At the same time, higher RES generation increases the export of ESO EAD market area from 4.9 TWh to 5.5 TWh (+11%) in average hydrological conditions. Export is also increased in dry hydrological conditions, for similar amount, pointing to the fact that the impact of hydrological conditions is limited. The increase of export 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 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 export.
- As a result, greater RES generation in both hydrological conditions leads to a decrease in prices for 4%.
- Higher RES capacities increase the need for flexibility and increases the utilization of PS HPPs, as it can be seen in Table 24.

Table 24: PS HPPs generation in ESO EAD market area

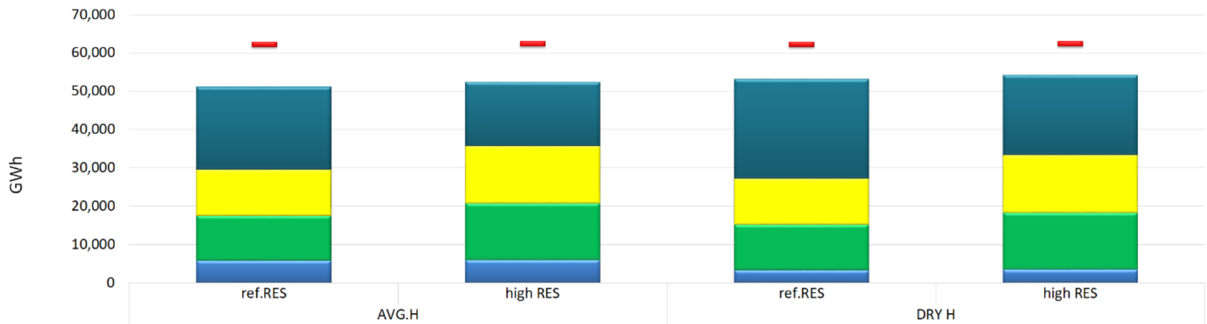
Generation from PS HPPs (GWh)	Average hydrological conditions	Dry hydrological conditions
Ref. RES	43.0	71.6
High RES	129.4	175.7
Difference	**86.4**	**104.1**

In general, engagement of PSHPPs is low (<200 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 is more than doubled 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 hydrological conditions) increases the engagement of this kind of power plants.

- In dry hydrological conditions, hydro generation is reduced for 25% (1.2 TWh) which is compensated by increase in TPPs generation (0.8 TWh) and decrease in export (0.4 TWh). Bulgarian thermal fleet becomes more competitive in dry hydrological conditions which leads to higher TPPs generation and higher prices in comparison with average hydrology.

5.1.4. IPTO market area

Generation mix and selected set of indicators, as the main results of market analysis for IPTO market area, are presented in Figure 34 and Figure 35, respectively.



	GR AVG.H ref.RES	GR AVG.H high RES	GR DRY H ref.RES	GR DRY H high RES
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 34: Generation mix in IPTO market area in 2030 - ref. RES vs high RES, dry and average hydrology

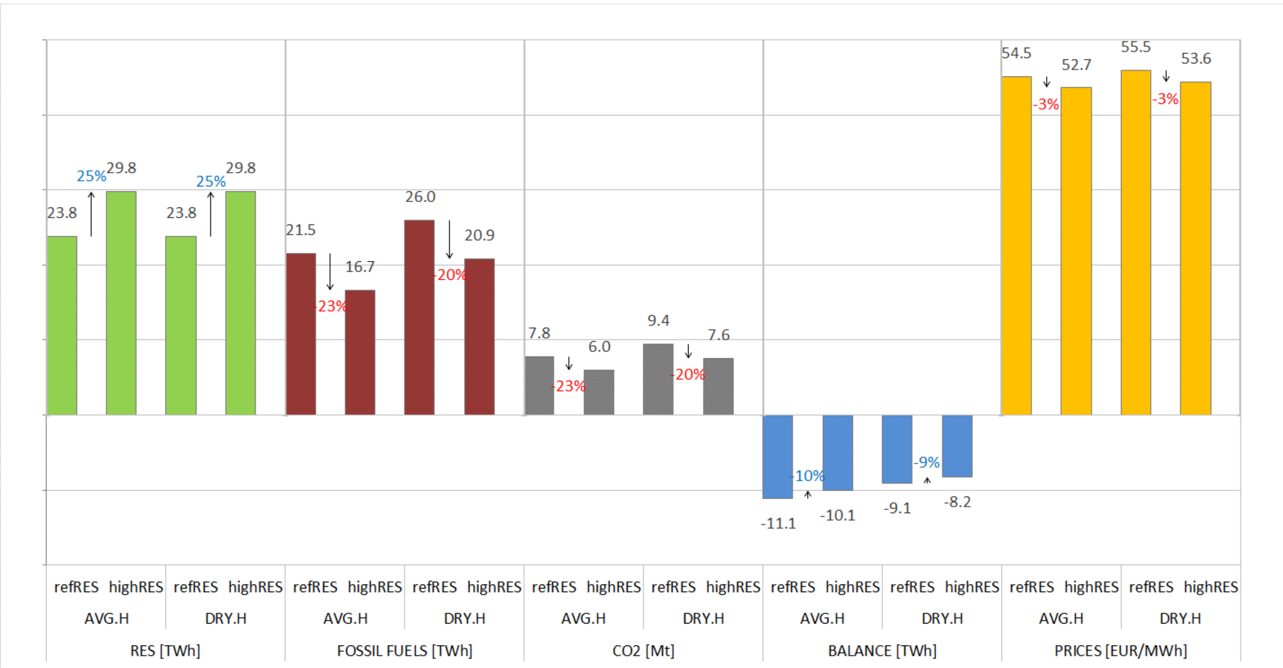


Figure 35: Main system operating indicators in IPTO market area in 2030 - ref. RES vs high RES, dry and average hydrology

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

- Beside Transelectrica market area, 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) 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 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 more than 20% (-4.8 TWh and -5.1 TWh) in both hydrological conditions and this decrease is (again) the highest in the region. Decrease is noted only in gas fired units and this leads to a decrease of CO2 emission for the same percentages.
- At the same time, difference in RES generation increase and TPPs generation decrease enables large net import of IPTO market area to decrease for around 1.1TWh or for 10%. However, even with additional generation from RES, import of IPTO market area remains 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).
- Participation of HPPs in supplying the demand in IPTO market area is rather low (<10%) and, although in dry hydrological conditions HPPs generation is decreased for around 40%, the impact of this is limited. Available energy in the whole EMI region in dry hydrological conditions is smaller, and regional merit order curve is moved to the left, so that gas-fired units in IPTO market area become more competitive. This increases the gas fired plants generation in dry hydrological conditions, increases the prices but also reduces the net import.
- Greater RES generation in both hydrological conditions leads to a decrease in prices for 3%. Impact of hydrological conditions is smaller and in the opposite direction – prices increase for around 1 EUR/MWh in dry hydrological conditions.
- Similar as in other market areas, engagement of PS HPPs is not so big (Table 25).

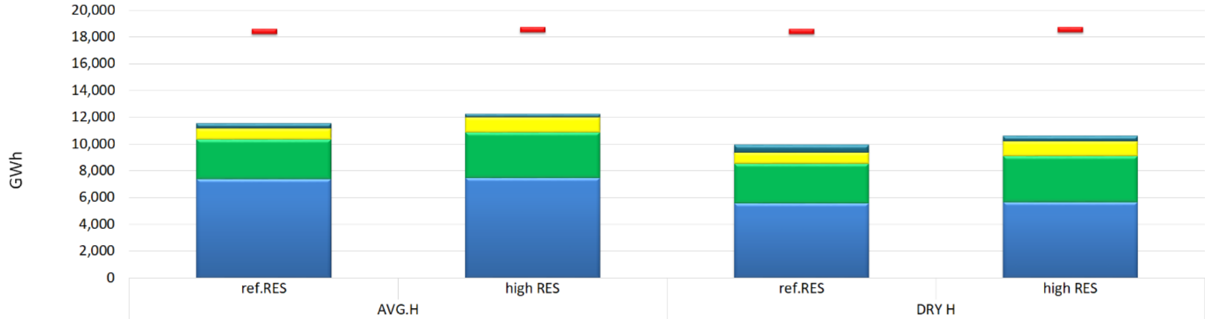
Table 25: PS HPPs generation in IPTO market area

Generation from PS HPPs (GWh)	Average hydrological conditions	Dry hydrological 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 in comparison with referent RES scenario, although it is still modest engagement. No impact of hydrological conditions points again to small impact of hydro generation in IPTO market area.

5.1.5. HOPS market area

Generation mix and selected set of indicators, as the main results of market analysis for HOPS market area, are presented in Figure 36 and Figure 37, respectively.



	ref.RES	high RES	ref.RES	high RES
	AVG.H		DRY H	
	HR			
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 36: Generation mix in HOPS market area in 2030 - ref. RES vs high RES, dry and average hydrology

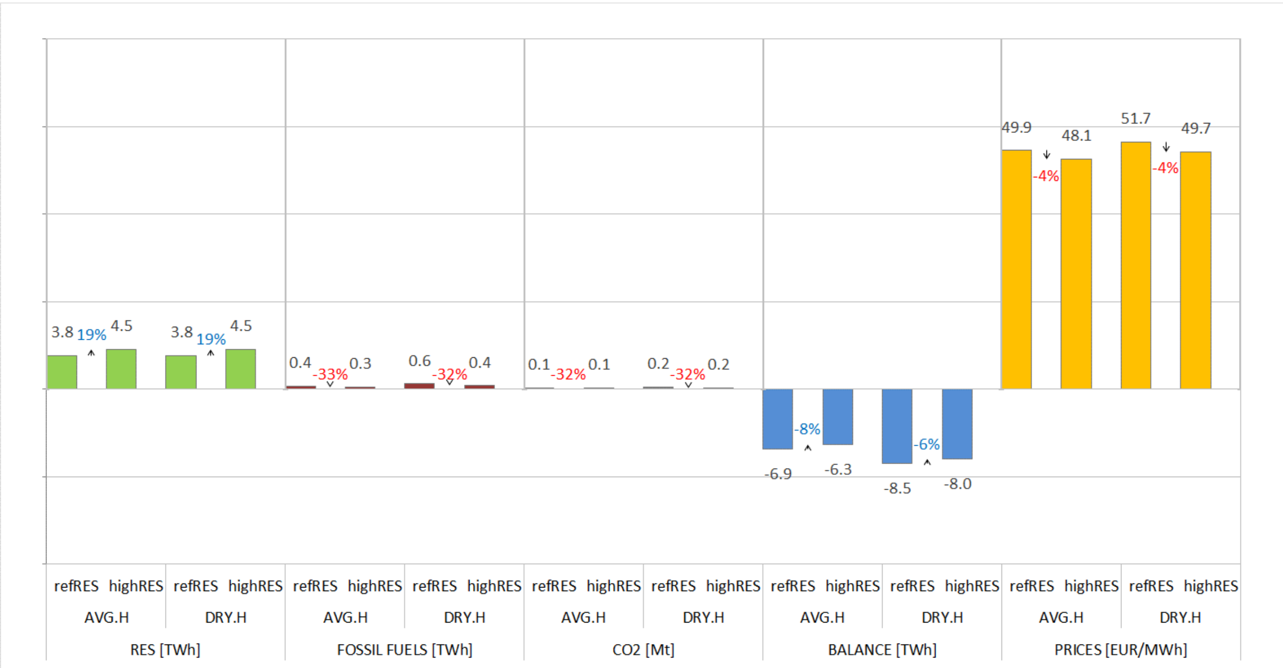


Figure 37: Main system operating indicators in HOPS market area in 2030 - ref. RES vs high RES, dry and average hydrology

Considering the generation mix presented in Figure 36, in conjunction with the main system indicators depicted in Figure 37, 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 hydrological conditions:

- RES generation (wind+solar) rise 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 is supplied by hydro and RES generation plus import. 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 hydrological conditions, TPPs generation is somewhat higher, but still below 1 TWh.
- Net import in HOPS market area is between 6.3 and 6.9 TWh (34% and 37% of the area demand) in average hydrological conditions and increases with decrease in generation from HPPs in dry hydrological condition, reaching 46% of total demand.
- Higher RES integration decreases the net import in all hydrological conditions for 6%-8%.
- As a result, greater RES generation in both hydrological conditions leads to a decrease in prices for 4%.
- Similar as in other market areas, engagement of PS HPPs is not so big (Table 26).

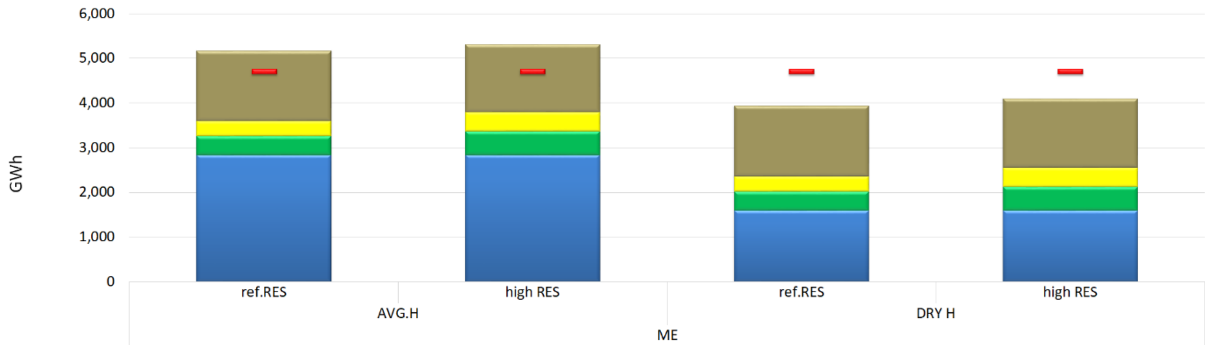
Table 26: PS HPPs generation in HOPS market area

Generation from PS HPPs (GWh)	Average hydrological conditions	Dry hydrological 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 interconnection provides enough flexibility.

5.1.6. CGES market area

Generation mix and selected set of indicators, as the main results of market analysis for CGES market area, are presented in Figure 38 and Figure 39, respectively.



	ME AVG.H ref.RES	ME AVG.H high RES	ME DRY H ref.RES	ME DRY H high RES
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 38: Generation mix in CGES market area in 2030 - ref. RES vs high RES, dry and average hydrology

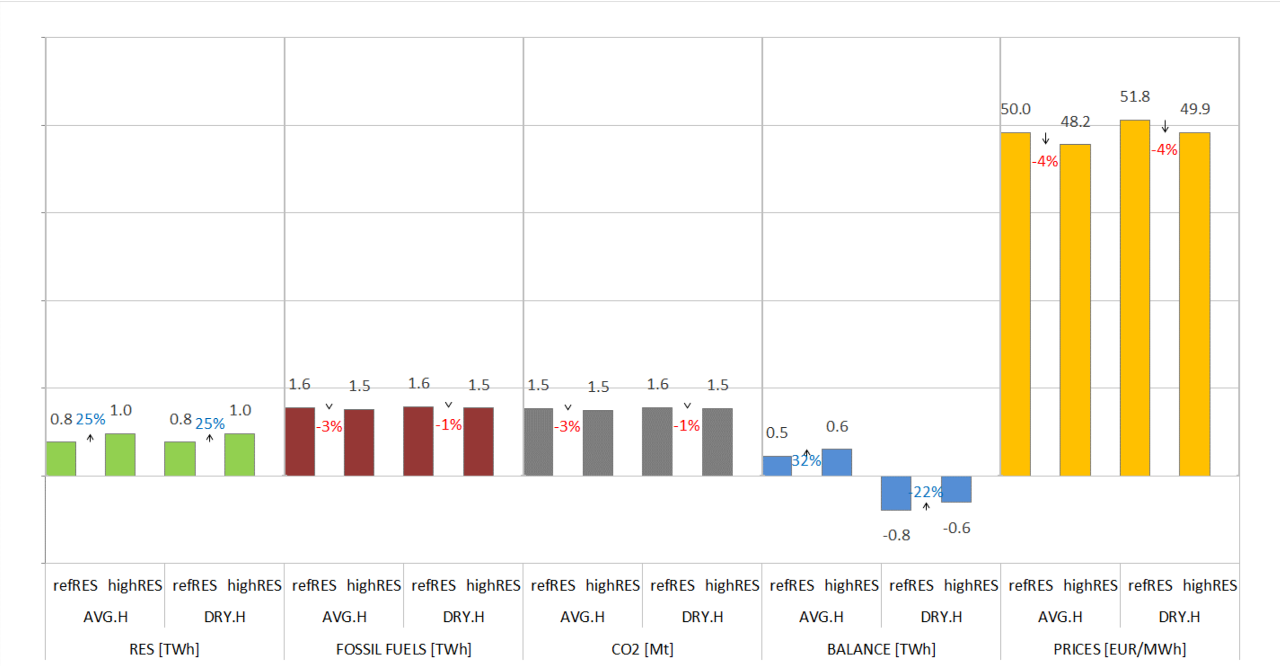


Figure 39: Main system operating indicators in CGES market area in 2030 - ref. RES vs high RES, dry and average hydrology

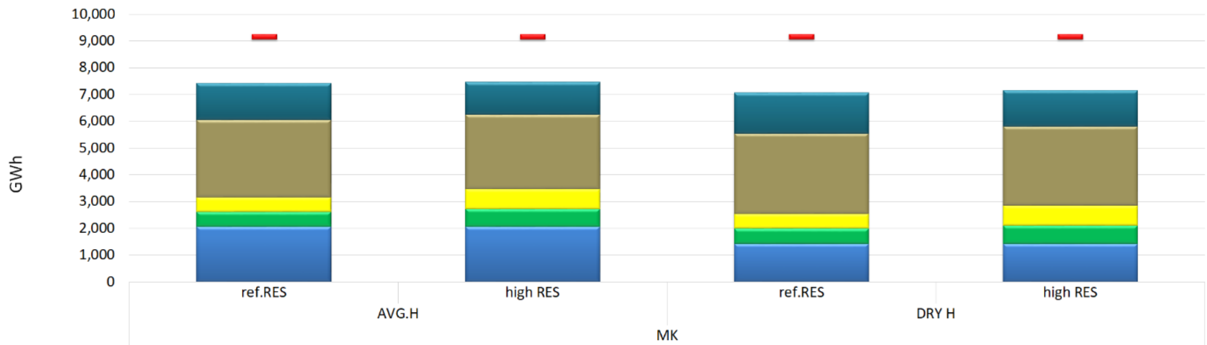
Considering the generation mix and main system indicators presented in the figures above the following conclusions could be drawn:

- CGES market area is the smallest, almost balanced market area in the EMI region
- RES generation (wind+solar) rise 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 hydrological conditions and small changes in CO2 emission.
- With higher RES generation, CGES market area increases its net export or decreases its net import, depending on the hydrological conditions.

- In dry hydrological conditions, generation from HPPs is decreased for 1.2 TWh (44%) and balance position is changed at the same level, moving from net export of 0.5 TWh to net import of 0.8 TWh, without changes in TPPs generation.

5.1.7. MEPSO market area

Generation mix and selected set of indicators, as the main results of market analysis for MEPSO market area, are presented in Figure 40 and Figure 41, 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 40: Generation mix in MEPSO market area in 2030 - ref. RES vs high RES, dry and average hydrology

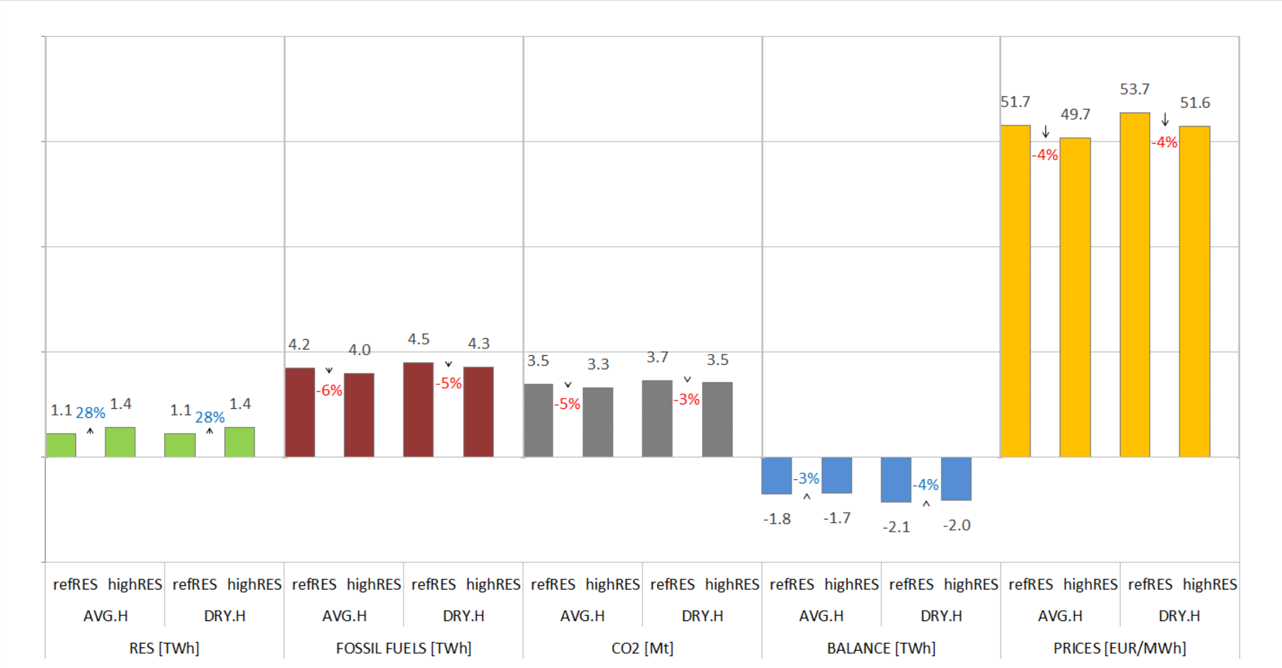


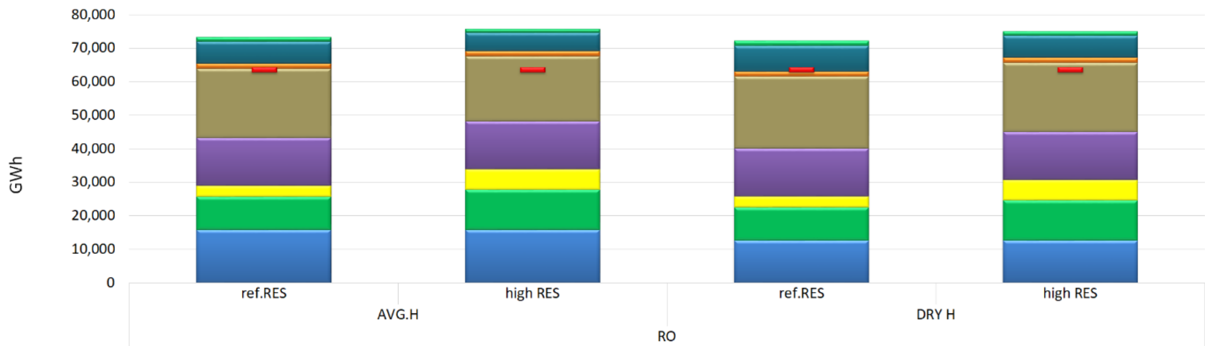
Figure 41: Main system operating indicators in MEPSO market area in 2030 - ref. RES vs high RES, dry and average hydrology

Considering the generation mix presented in Figure 40, in conjunction with the main system indicators depicted in Figure 41, 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 hydrological conditions:

- RES generation (wind+solar) rise 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 for about 0.25 TWh (-6%) in both hydrological conditions and decrease of import (-0.1 TWh).
- Decrease in fossil fuel fired plants generation decreases the CO2 emission for 5% and 3 % in average and dry hydrological conditions, respectively.
- Net import slightly decrease with higher RES generation, but in all scenarios MEPSO market area is a net importer.
- As a result, greater RES generation in both hydrological conditions leads to a decrease in prices for 4%.
- In dry hydrological conditions, hydro generation is reduced for 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 hydrological conditions which leads to higher TPPs generation and higher prices (+2 EUR/MWh) in comparison with average hydrology.

5.1.8. Transelectrica market area

Generation mix and selected set of indicators, as the main results of market analysis for Transelectrica market area, are presented in Figure 42 and Figure 43, 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 42: Generation mix in Transelectrica market area in 2030 - ref. RES vs high RES, dry and average hydrology

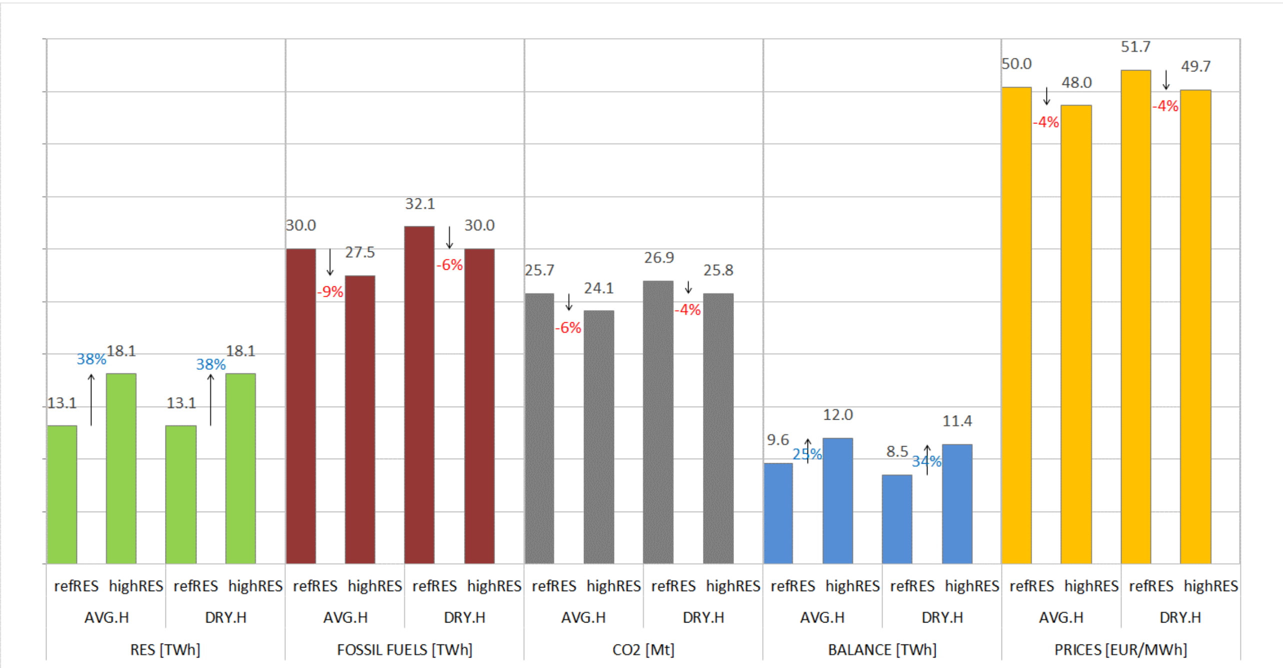


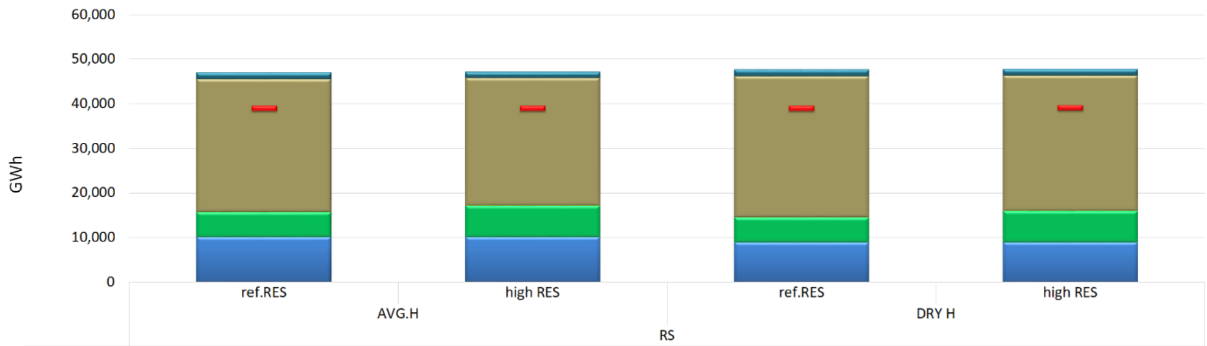
Figure 43: Main system operating indicators in Transelectrica market area in 2030 - ref. RES vs high RES, dry and average hydrology

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 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 Transelectrica market area is at the regional average, between 21% and 28%.
- At the same time, generation of fossil fuels fired TPPs fall from 30.0 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 for 6% and 4% since total decrease in TPPs generation is almost equally divided between gas and lignite fired TPPs.
- In dry hydrological conditions, TPPs generation is increased to compensate reduction in HPPs generation. In dry hydrological 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 Transelectrica market area become more competitive. This is also the reason for smaller decrease in TPPs generation with additional RES generation expected in high RES scenario (-6%).
- With higher RES generation, the net export of Transelectrica market area rises for 2.4 TWh (25%) in average hydrological conditions. In dry hydrological conditions, this increase is even higher and export increases for 2.9 TWh or 34%.
- Greater RES generation in both hydrological conditions leads to a decrease in prices for 4%. With increased RES generation cheaper power plants become marginal and prices decrease.
- In dry hydrological conditions, hydro generation is reduced for 20% (3.2 TWh) which is compensated by increase in TPPs generation (2.1 TWh) and decrease in export (1.1 TWh). At the same time, prices in dry hydrological conditions are higher for 1.7 EUR/MWh

5.1.9. EMS market area

Generation mix and selected set of indicators, as the main results of market analysis for EMS market area, are presented in Figure 44 and Figure 45 , respectively.



RS	AVG.H ref.RES	AVG.H high RES	DRY H ref.RES	DRY H high RES
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 44: Generation mix in EMS market area in 2030 - ref. RES vs high RES, dry and average hydrology

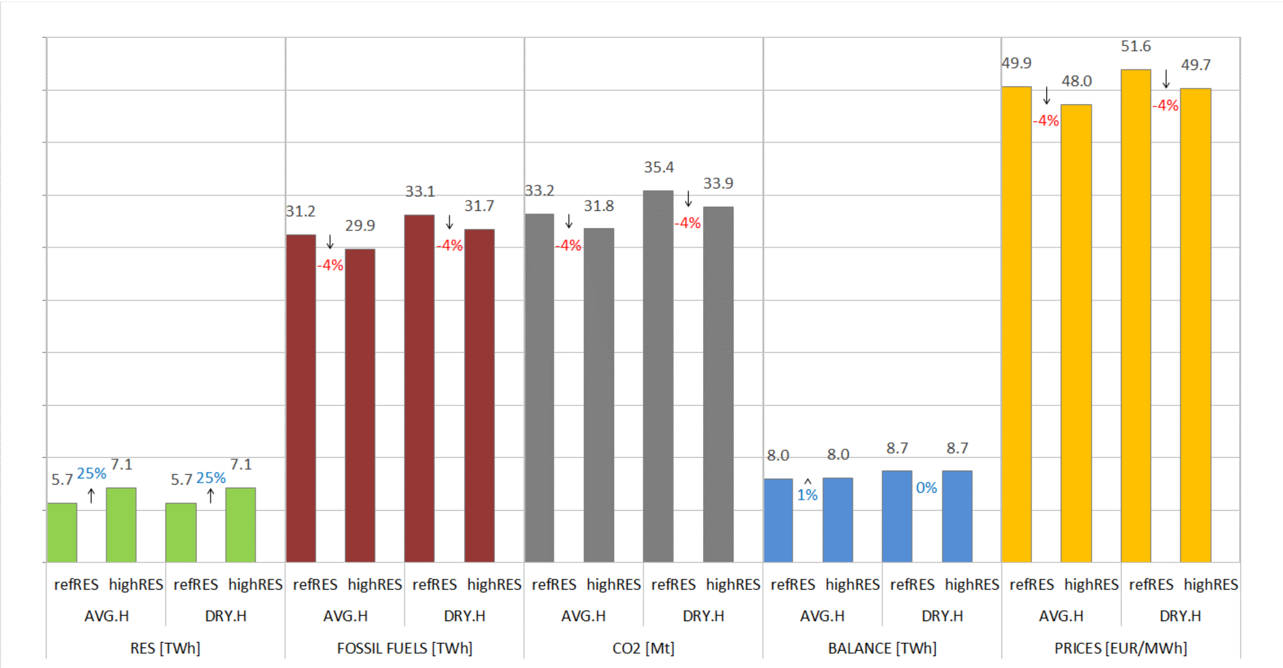


Figure 45: Main system operating indicators in EMS market area in 2030 - ref. RES vs high RES, dry and average hydrology

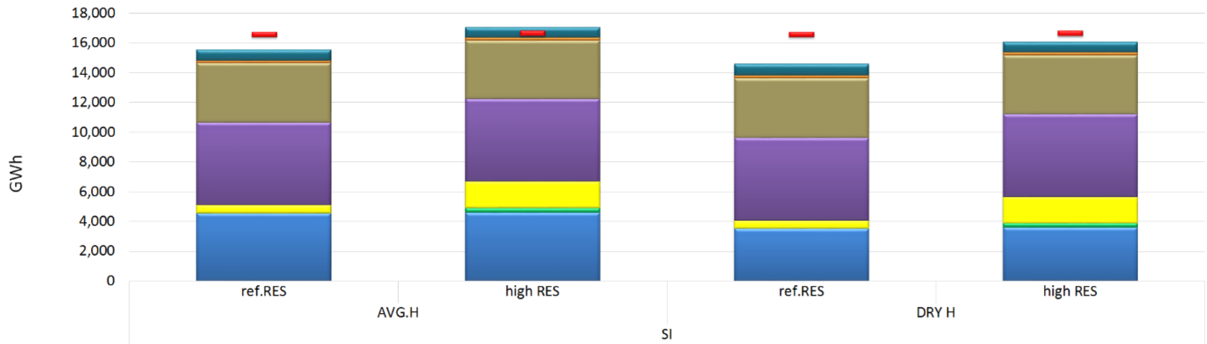
Considering the generation mix presented in Figure 44, in conjunction with the main system indicators depicted in Figure 45, the following conclusions could be drawn about the operation of this market area in the high RES scenario, in comparison with ref. RES in dry and average hydrological conditions:

- RES generation (wind+solar) rise 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 emission decreases with the same percentage.
- At the same time, the export of EMS market area is practically the same. Increase in RES generation push generation from TPPs for the same value and export remains the same in both hydrological conditions.
- More critical operating conditions as with dry hydrology puts thermal fleet in EMS market area in more competitive position and enables higher thermal generation and higher export. HPPs generation in dry hydrological conditions is lower for 1.2 TWh, but TPPs increase their generation for 1.9 TWh and net export from EMS market area is increased for 0.7 TWh.
- As a result, greater RES generation in both hydrological conditions leads to a decrease in prices for 4%, 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 pointing to the fact that existing hydropower plants and strong regional connections enables enough flexibility for the given level of RES generation.

5.1.10. ELES market area

Generation mix and selected set of indicators, as the main results of market analysis for ELES market area, are presented in Figure 46 and Figure 47, respectively.



	AVG.H ref.RES	AVG.H high RES	DRY H ref.RES	DRY H high RES
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 46: Generation mix in ELES market area in 2030 - ref. RES vs high RES, dry and average hydrology

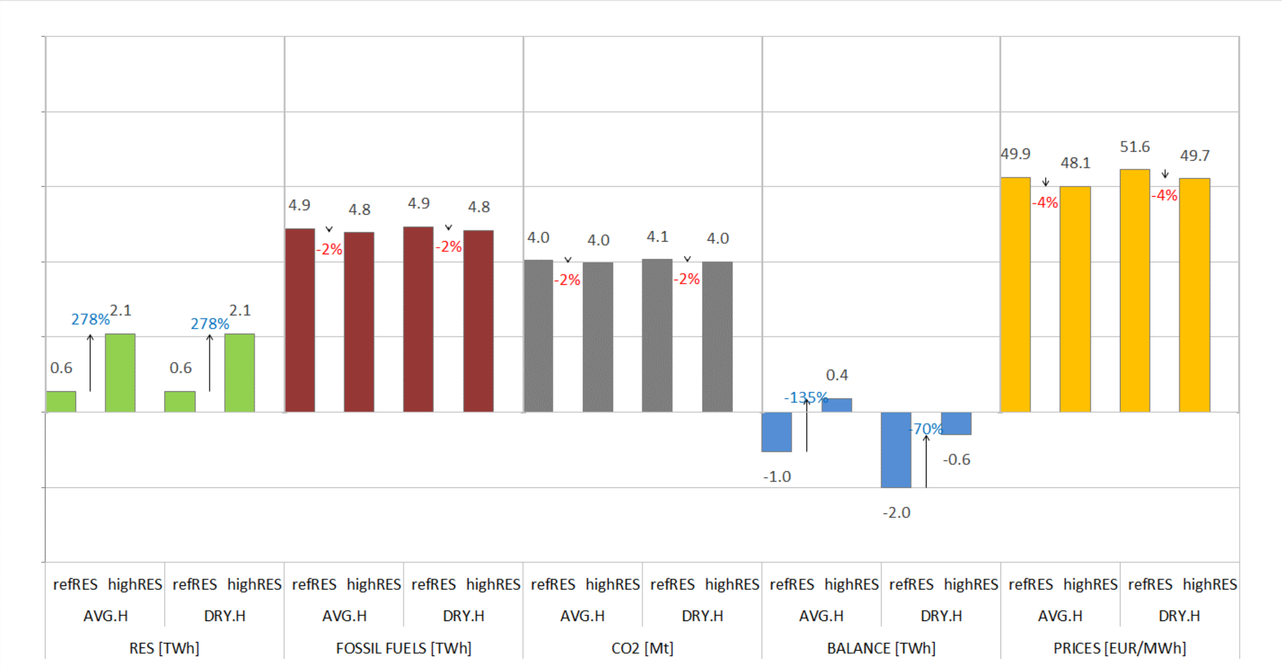


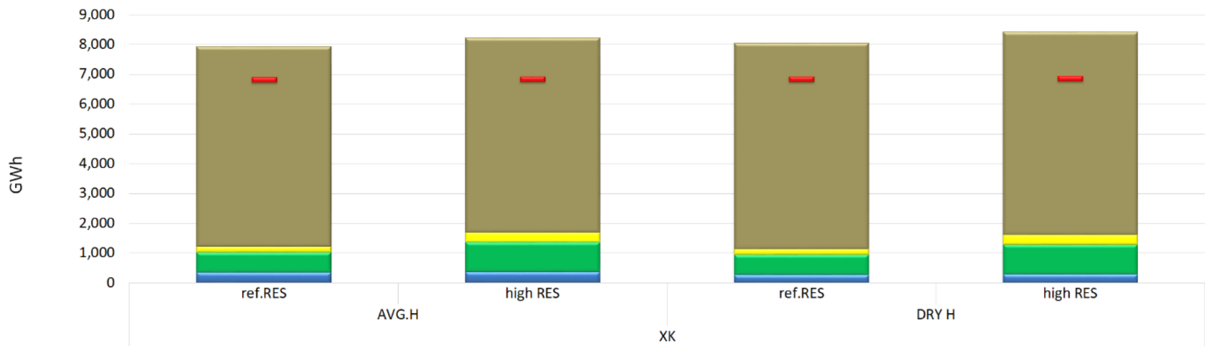
Figure 47: Main system operating indicators in in ELES market area in 2030 - ref. RES vs high RES, dry and average hydrology

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

- 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 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 0.1 TWh (2%) 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 hydrological conditions, but with reduced HPPs generation, ELES market area remains as net importer in both scenarios: referent and high RES.
- Higher RES generation leads to decrease of CO_2 emissions by 2% for both, average and dry hydrological conditions.
- As a result, greater RES generation in both hydrological conditions leads to a decrease in prices for 4%. Namely, with increase in RES generation cheaper power plants become marginal.
- Simulations shows that engagement of PS HPP is very small pointing to the fact that existing hydropower plants and strong regional connections enables enough flexibility for the given level of RES generation.

5.1.11. KOSTT market area

Generation mix and selected set of indicators, as the main results of market analysis for the KOSTT market area, are presented in Figure 48 and Figure 49 , 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 48: Generation mix in KOSTT market area in 2030 - ref. RES vs high RES, dry and average hydrology

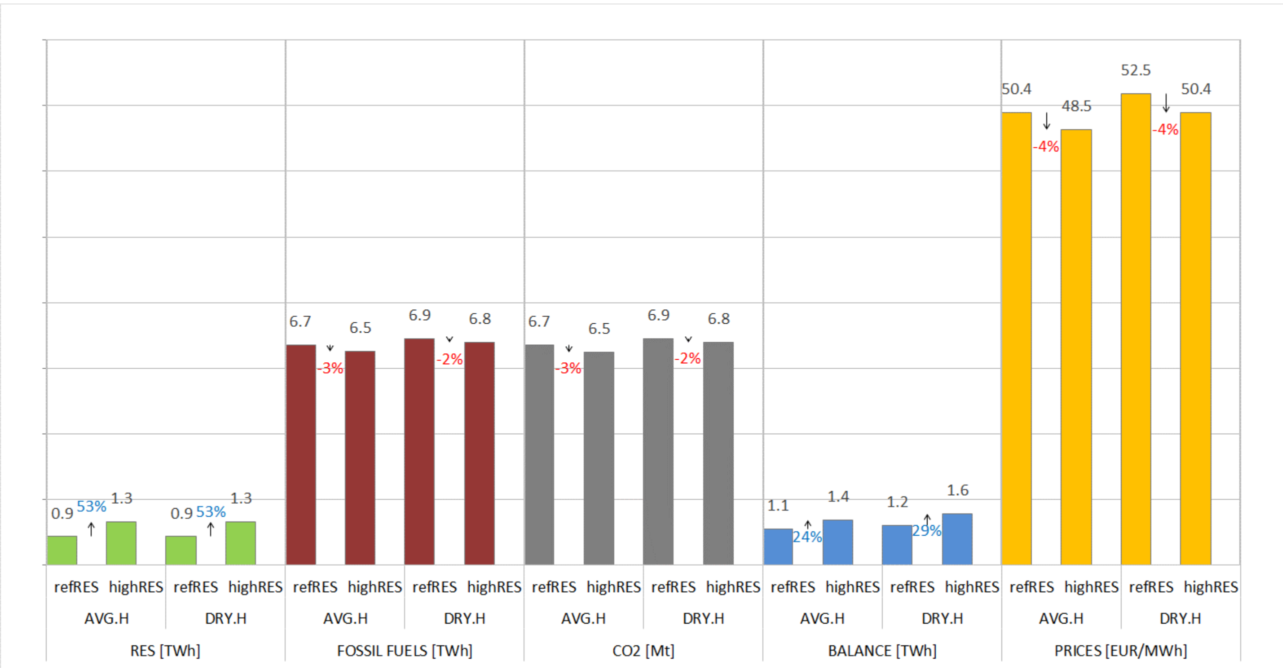


Figure 49: Main system operating indicators in KOSTT market area in 2030 - ref. RES vs high RES, dry and average hydrology

Considering the generation mix presented in Figure 48, in conjunction with the main system indicators depicted in Figure 49, 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 hydrological conditions:

- RES generation (wind+solar) rise 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 0.1-0.2 TWh (2-3%) and decrease in CO2 emission is proportional.
- KOSTT market area is expected to be net exporter, as it can be seen from the Figure 49. with export 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 dry hydrological conditions. Similar as in other market areas, reduction in TPPs generation is lower than increase in RES generation and area exports more in high RES scenario.
- In dry hydrological conditions, thermal power plants in KOSTT market area produce more partially compensating decrease in HPPs and increasing the export.
- As a result, greater RES generation for both hydrological conditions leads to a decrease in prices for 4%. 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 pointing to the fact that existing hydropower plants and strong regional connections enables enough flexibility for the given level of RES generation.

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

Similar to the first set of results given in the Chapter 6.1 in the second group of scenarios, referent demand development and alternative (high) CO_2 emission tax have been set and kept constant in 4 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

Generation mix for the whole EMI region is given on Figure 50, while main indicators are presented in Figure 51.

SEE	AVG.H ref.RES	AVG.H high RES	DRY H ref.RES	DRY H high RES
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 50: Generation mix in EMI region in 2030 - ref. RES vs high RES, dry and average hydrology – Alternative CO_2 emission tax

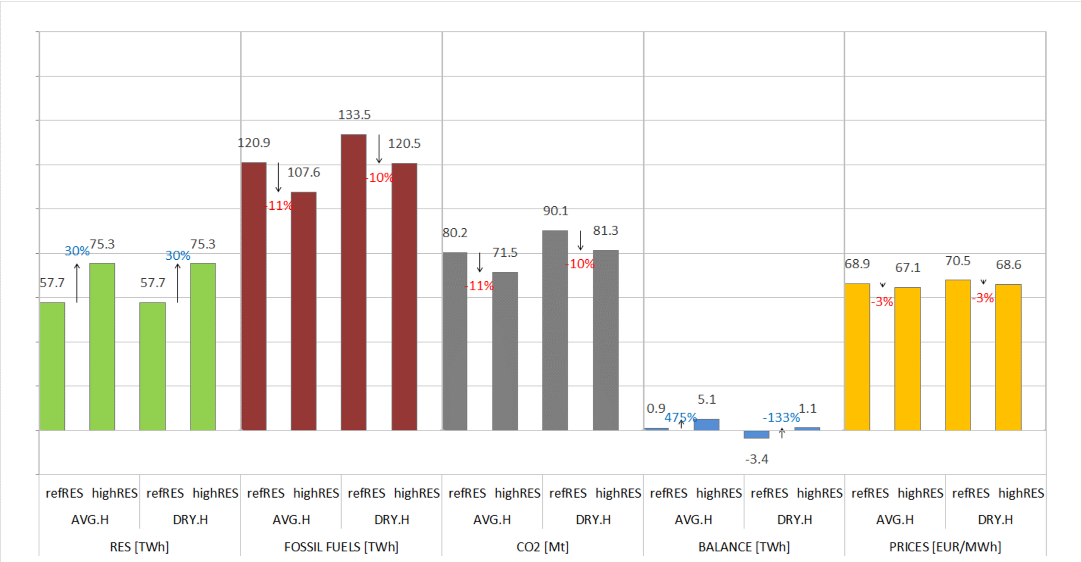


Figure 51: Main system operating indicators in EMI region in 2030 - ref. RES vs high RES, dry and average hydrology – Alternative CO_2 emission tax

From the above mentioned results we can draw the following conclusions:

- **Main technology in 2030 is hydro in the case of average hydrological conditions and it supplies approx. 24% of the load, while in the case of dry hydrological conditions lignite and gas supplies almost the same share of the load: between 18% and 23%.** Higher level of CO_2 emission tax (in comparison with referent level) changes the position of the lignite and gas fired plants in the merit order curve and decreases competitiveness of the lignite fired plants which leads to decrease of their generation for ~30TWh (or 50%). At the same time generation in gas fired plants is increased.
- Hydro power plants supply between 18% and 24%, depending on the hydrology, while RES generation (depending on the scenario) supplies between 21% and 27% of total demand. It can be asserted that hydro and RES technologies, which can be considered as "green"

technologies, become main technologies in EMI region in 2030 and supply between 39% and 51% of total demand. This is the same as in case of referent CO_2 tax, since change in CO_2 emission tax has an impact only on generation from fossil fuelfired plants.

- Same as in case of referent CO_2 tax, RES generation increases from 57.7 TWh (in ref. RES scenario) to 75.3 TWh in high RES scenario which is the increase of 30% (Figure 51). Increase per market areas (Figure 52) is between 0.2 and 6 TWh (in CGES and IPTO market areas) or between 19% and 278% (in HOPS and ELES market areas respectively).

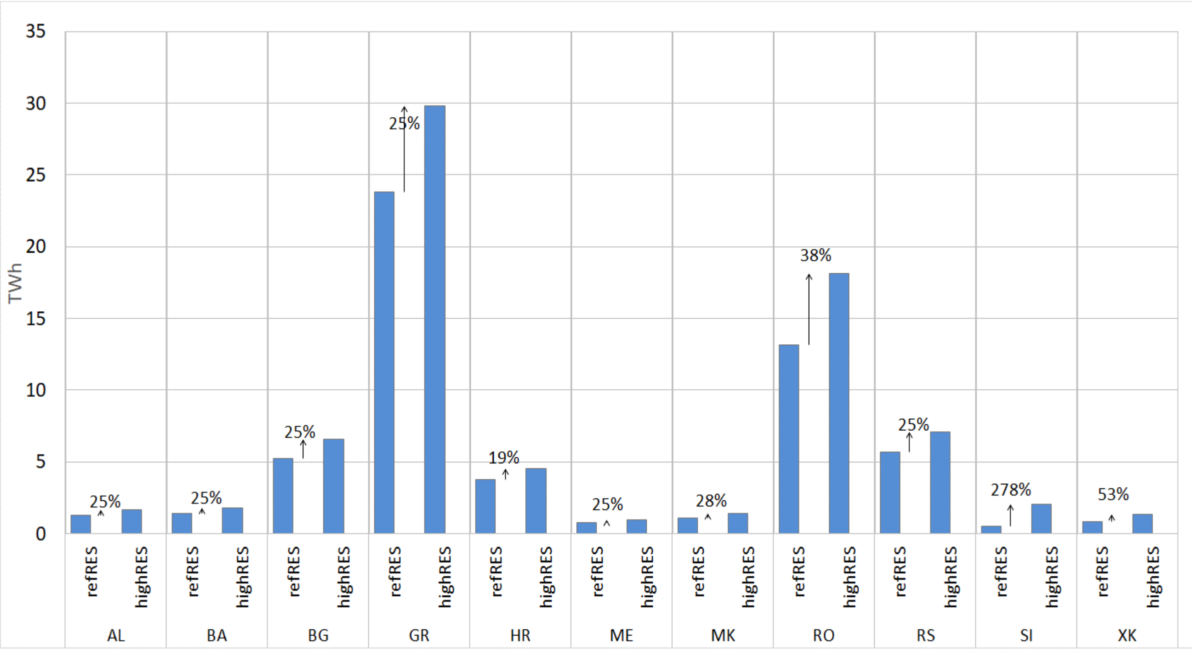


Figure 52: RES generation in 2030 - ref. RES vs high RES

- **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 powered plants generation is decreased: gas fired plants generation is decreased for 8 TWh, lignite fired plants for 5 TWh, and, export from the region is increased for 4 TWh.**
  Since the share of gas and lignite fired plants is similar, increase in RES generation has similar impact on both. However, somewhat higher decrease in generation from gas fired plants lies in the fact that in one of the biggest market areas in the region (IPTO) in 2030 only gas fired units exist. In all other market areas, decrease of fossil fuel fired plants generation, due to increased generation from RES, is almost equally divided between lignite and gas technologies (Figure 53).

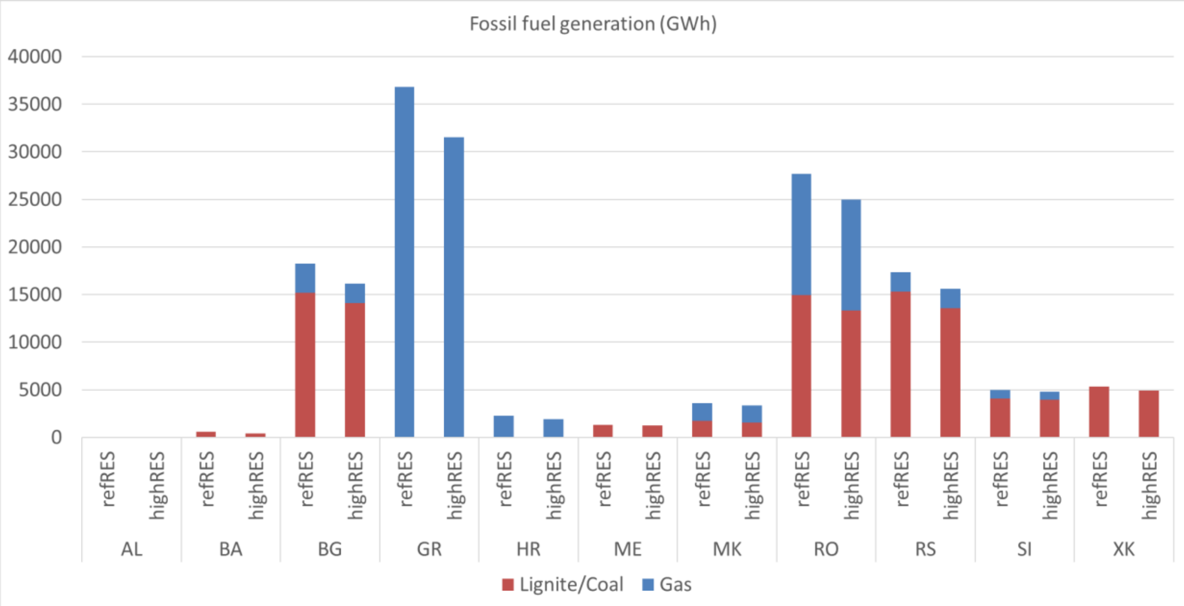


Figure 53: Fossil fuel powered plants generation in 2030 - ref. RES vs high RES, average hydrology – Alternative CO_2 emission tax

- **Following decrease in fossil fuels fired plants generation, CO_2 emission is decreased with high RES integration and this decrease is around 11% or 9 Mt of CO_2 for the whole EMI region.**
- **EMI region is almost balanced with net export 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 hydrological conditions and the referent IRES integration. In the case of that scenario EMI region is a net importer with import of 3 TWh or approx. 1% of total demand.**
- Higher RES generation provokes decrease of TPPs generation but at the smaller level, and this leads to increase of the net export. Increase of export at regional level is around 4.2 TWh and is similar in both hydrological conditions. Increase in next export in high RES scenario is lower than in case with referent CO_2 tax since the competitivnes of the fossil fuels fired plants in EMI region is lower and decrease in their generation is bigger.
- Changes in balance positions for all market zones in average hydrological conditions (Figure 54) shows that in almost all countries, due to additional RES generation, export is increased or import is decreased. The only different behavior can be seen in ESO EAD and EMS market areas where fossil fuel (gas+lignite) fired plants become less competitive which leads to decrease of export and increase of import, respectively.

  It should be also noted that in case of higher CO_2 tax, lignite fired plants in KOSTT, NOSBIH and EMS market areas become less competitive and these areas become net importers. At the same time, gas fired plants in ADMIE market area become competitive and this area becomes net exporter. This change leads to completely different energy flows in the region with reduced congestions and equalization of prices.

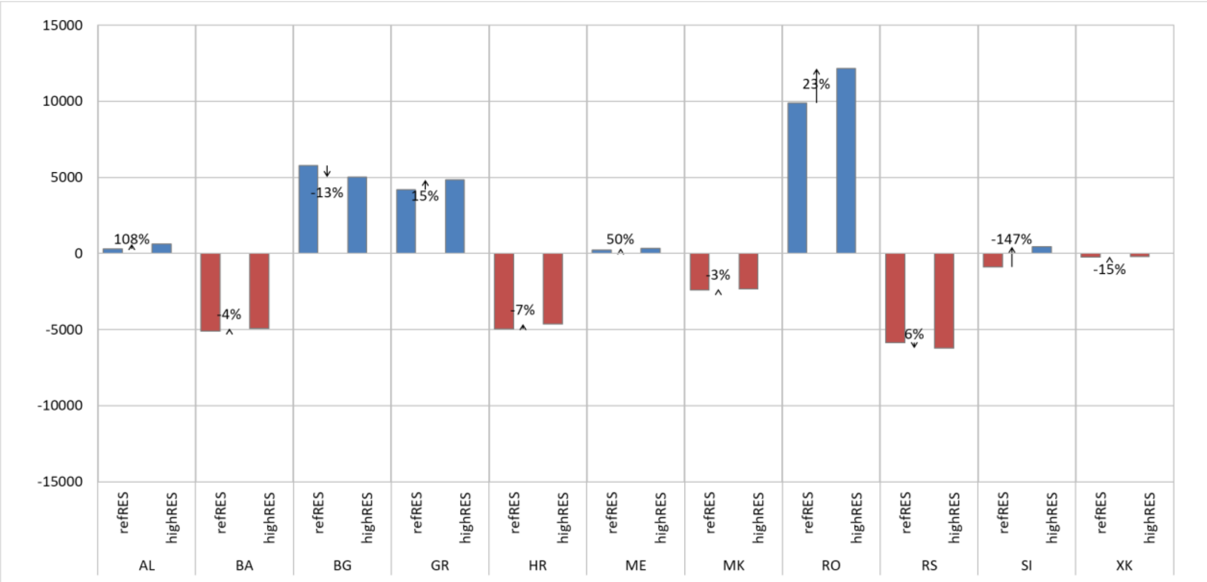


Figure 54: Balance positions per market areas in 2030 - ref. RES vs high RES, average hydrology – Alternative CO_2 emission tax

- **Average regional prices (Figure 51) are between 67.1 and 70.5 EUR/MWh with decrease provoked by high RES integration of around 2 EUR/MWh or 2,7% in both hydrological conditions.** From the same figure it could be seen that prices in dry hydrological conditions would be higher for around 1.5 EUR/MWh or 2.3%.

Figure 55: Prices in EMI region in 2030 - ref. RES, average hydrology – Alternative CO_2 emission tax

From Figure 55 it could be seen that electricity prices are evenly distributed across the EMI region without significant deviations from average price on regional level.

- Decrease of HPPs generation in dry hydrological conditions provokes higher TPPs generation that partially compensates the reduced HPPs generation while the other part of this reduction is compensated by the reduction in the regional export. These changes lead to increased prices, but change is rather small – 1.5 EUR/MWh at the regional level.

- Available energy in the whole EMI region in dry hydrological conditions is smaller, and 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. This move of the merit order curve has different impact on balance positions change in different countries. In majority of market areas balance positions are changed in the same direction (net export is decreased or net import is increased) but in some (like ESO EAD, IPTO, EMS and KOSTT), where TPPs become more competitive, import decrease (in EMS market area), export 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 56.

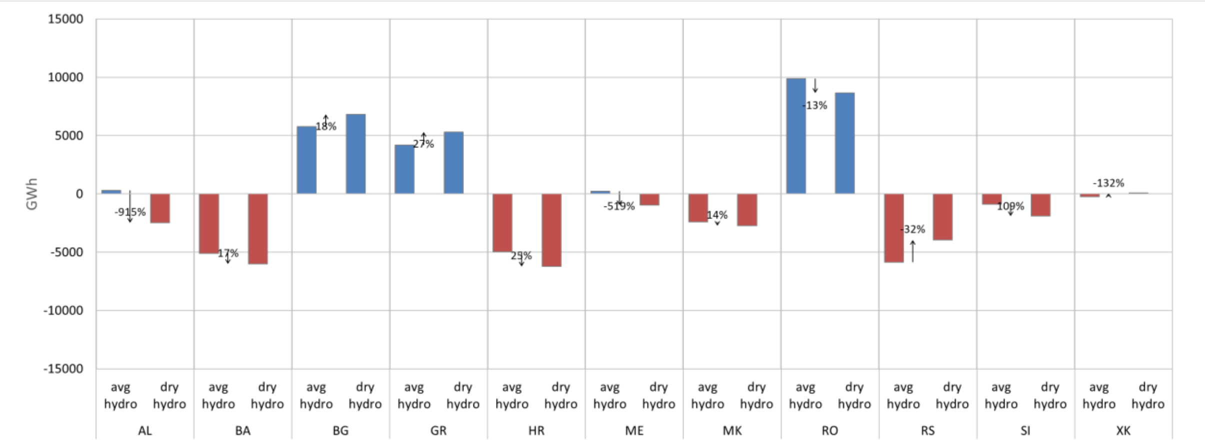
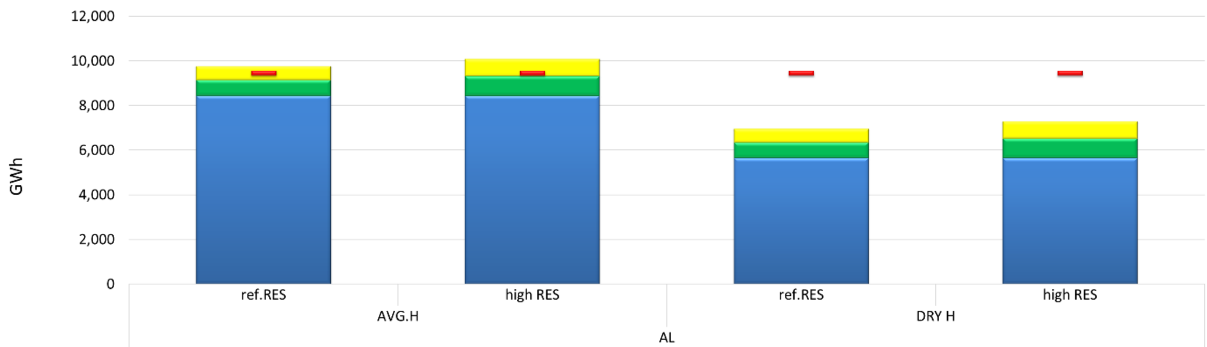


Figure 56: Balance positions per market areas in 2030 – average vs. dry hydrology , ref. RES – Alternative CO2 emission tax

In the following chapters, detailed overview of the results per market areas are presented.

5.2.1. OST market area

Generation mix and selected set of indicators, as the main results of market analysis for OST market area, are presented in Figure 57 and Figure 58, respectively.



	AL AVG.H ref.RES	AL AVG.H high RES	AL DRY H ref.RES	AL DRY H high RES
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 57: Generation mix in OST market area in 2030 - ref. RES vs high RES, dry and average hydrology – Alternative CO_2 emission tax

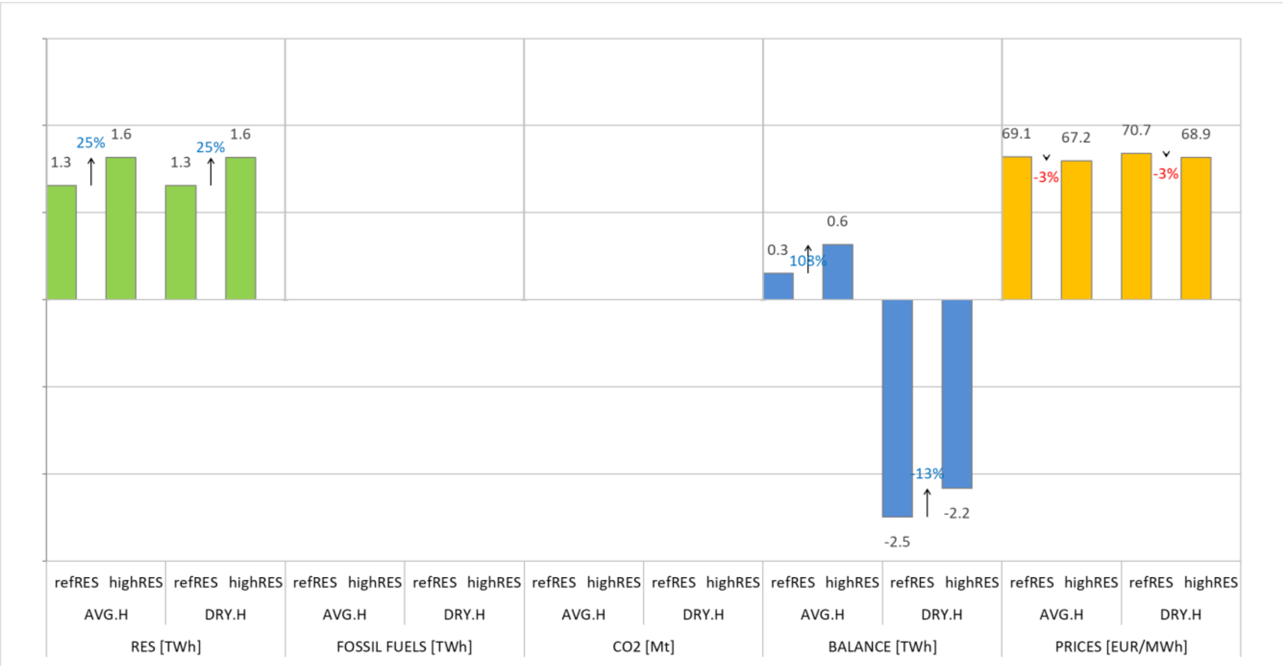


Figure 58: Main system operating indicators in OST market area in 2030 - ref. RES vs high RES, dry and average hydrology – Alternative CO_2 emission tax

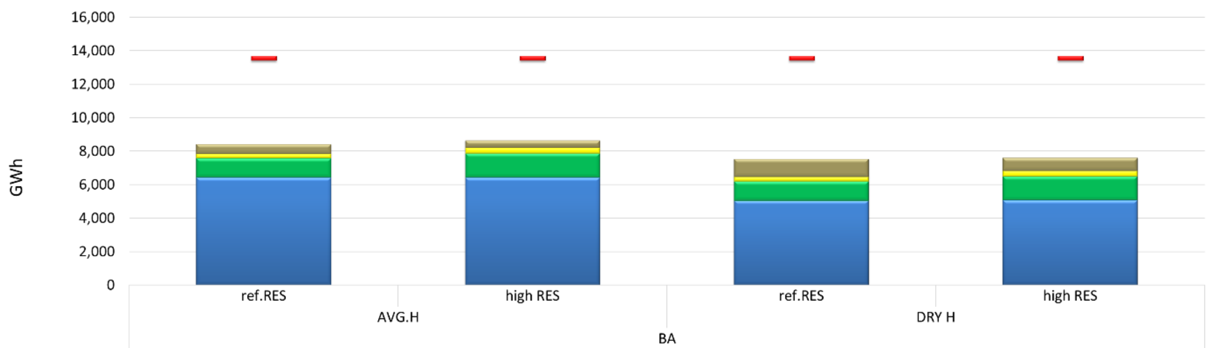
Considering the generation mix presented in Figure 57, in conjunction with the main system indicators depicted in Figure 58, the following conclusions could be drawn about the operation of this market area in the high RES scenario, in comparison with ref. RES in dry and average hydrological conditions:

- 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 14% and 17% of the area demand.

- Having in mind that OST market area is characterized with high hydro generation, its operation strongly depends on hydrological conditions. In average hydrological conditions OST market area is balanced (with small net export), but in dry hydrological conditions, with hydro generation reduced for 2.8 TWh (33%), import is high (2.5 TWh), reaching 26% of total area demand.
- Impact of RES integration on prices is the same as on the regional level (-2 EUR/MWh). Impact of hydrological conditions on prices is on the similar level but in the opposite direction (around 2 EUR/MWh increase in dry hydrological conditions).

5.2.2. NOSBIH market area

Generation mix and selected set of indicators, as the main results of market analysis for NOSBIH market area, are presented in Figure 59 and Figure 60, respectively.



	BA AVG.H ref.RES	BA AVG.H high RES	BA DRY H ref.RES	BA 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 59: Generation mix in NOSBIH market area in 2030 - ref. RES vs high RES, dry and average hydrology – Alternative CO_2 emission tax

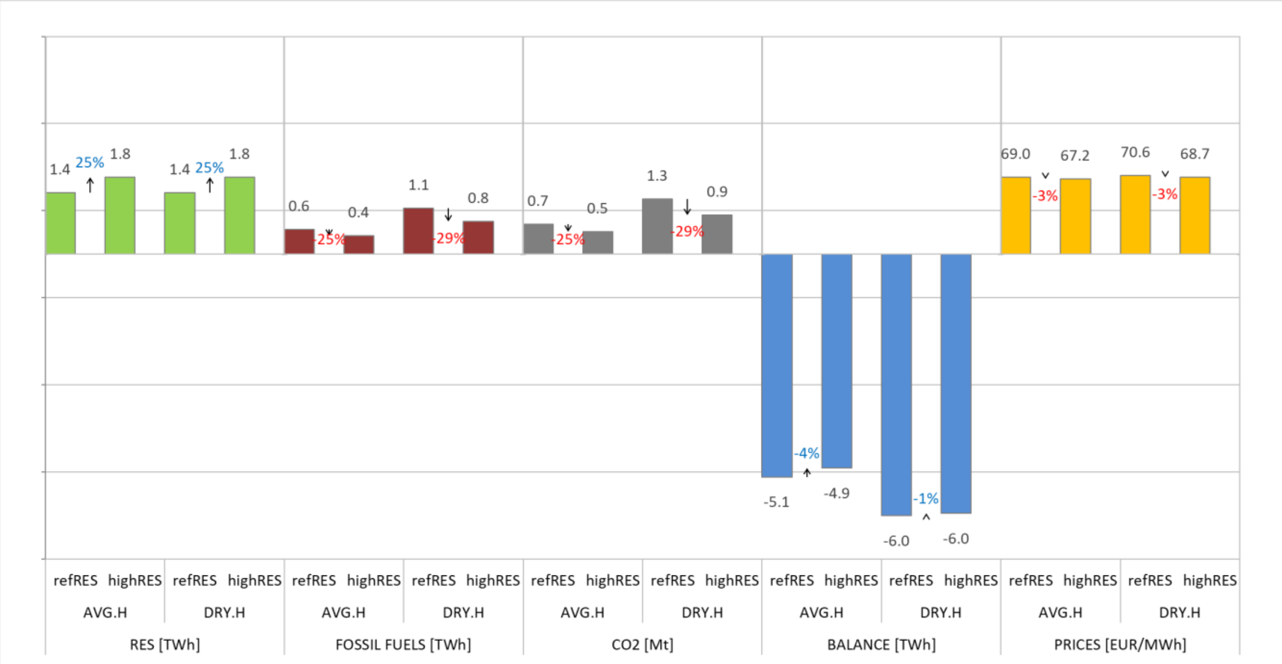


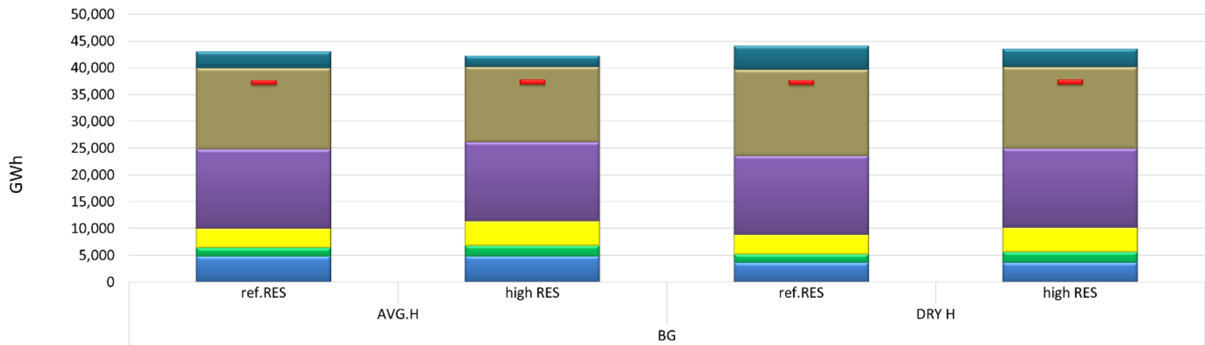
Figure 60: Main system operating indicators in NOSBIH market area in 2030 - ref. RES vs high RES, dry and average hydrology – Alternative CO_2 emission tax

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

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

5.2.3. ESO EAD market area

Generation mix and selected set of indicators, as the main results of market analysis for ESO EAD market area, are presented in Figure 61 and Figure 62, 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 61: Generation mix in ESO EAD market area in 2030 - ref. RES vs high RES, dry and average hydrology – Alternative CO_2 emission tax

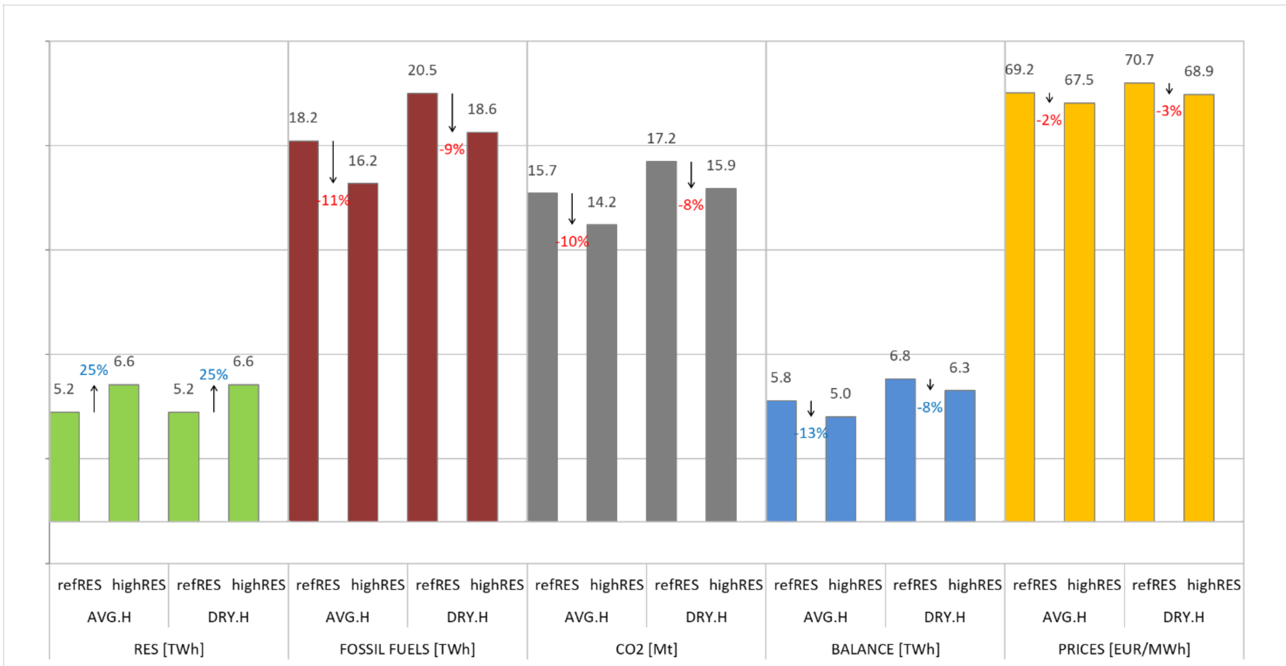


Figure 62: Main system operating indicators in ESO EAD market area in 2030 - ref. RES vs high RES, dry and average hydrology – Alternative CO_2 emission tax

Considering the generation mix presented in Figure 61, in conjunction with the main system indicators depicted in Figure 62, 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 hydrological conditions:

- RES generation (wind+solar) rise 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 for 9-11% (-1.9 TWh and -2.1 TWh), depending on hydrological conditions. This decrease leads to a decrease of CO2 emission for 8-10%.
- At the same time, higher RES generation decreases the export of ESO EAD market area from 5.8 TWh to 5.0 TWh (-13%) in average hydrological conditions. Export is also decreased in dry hydrological conditions, for slightly less amount -0.56 TWh (8%). It should be noted that dry hydrological 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 hydrological conditions leads to a decrease in prices for 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*.

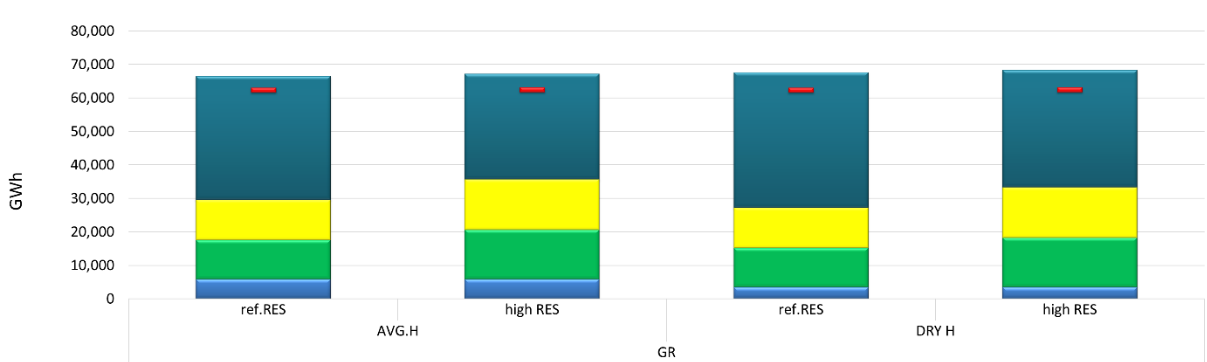
Table 27: PS HPPs generation in ESO EAD market area – Alternative CO_2 emission tax

Generation from PS HPPs (GWh)	Average hydrological conditions	Dry hydrological 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 hydrological conditions) increases the engagement of this kind of power plants.

5.2.4. IPTO market area

Generation mix and selected set of indicators, as the main results of market analysis for IPTO market area, are presented in Figure 63 and Figure 64, 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 63: Generation mix in IPTO market area in 2030 - ref. RES vs high RES, dry and average hydrology – Alternative CO_2 emission tax

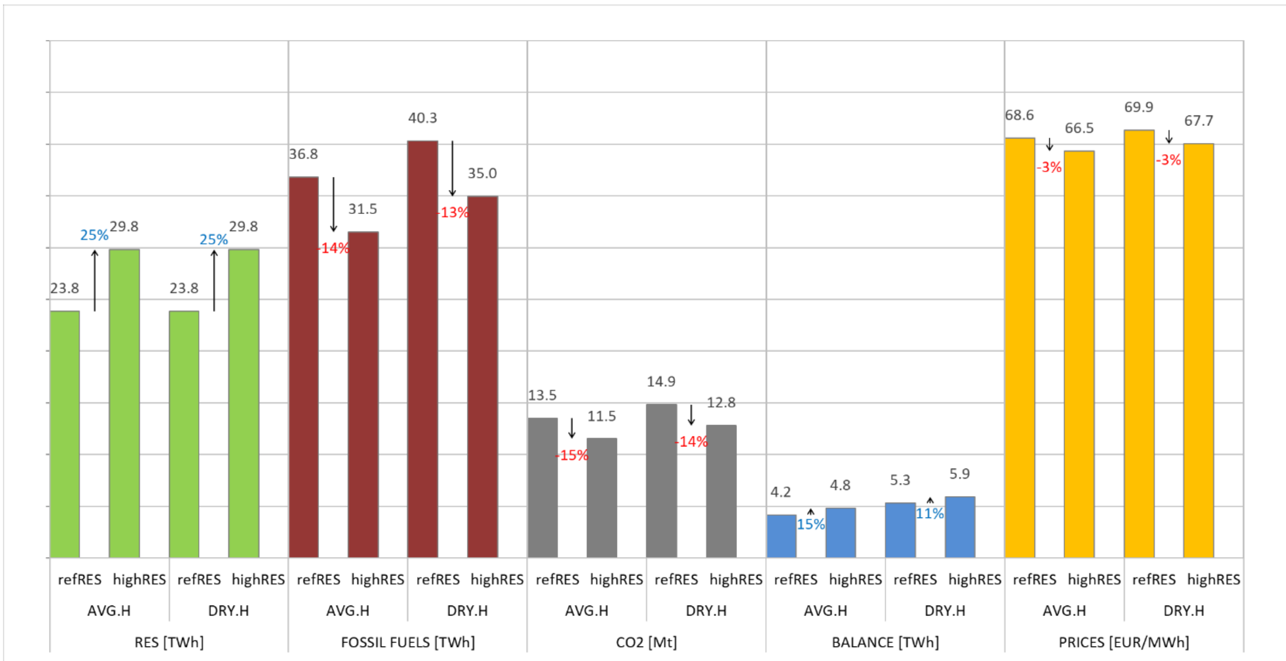


Figure 64: Main system operating indicators in IPTO market area in 2030 - ref. RES vs high RES, dry and average hydrology – Alternative CO_2 emission tax

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

- Beside Transelectrica market area, 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) 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 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 hydrological conditions. Decrease is noted only in gas fired units and this leads to a decrease of CO_2 emission 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 hydrological conditions).
- Participation of HPPs in supplying the demand in IPTO market area is rather low (<10%) and, although in dry hydrological conditions HPPs generation is decreased for around 40%, the impact of this is limited. Available energy in the whole EMI region in dry hydrological conditions is smaller, and regional merit order curve is moved to the left, so that gas-fired units in IPTO market area become more competitive. This increases the gas fired plants generation in dry hydrological conditions, increases the prices but also increases the net export.
- Greater RES generation in both hydrological conditions leads to a decrease in prices for 3%. Impact of hydrological conditions is smaller and in the opposite direction – prices increase for around 1 EUR/MWh in dry hydrological conditions.
- Similar as in other market areas, engagement of PS HPPs is not so big (*Table 28*).

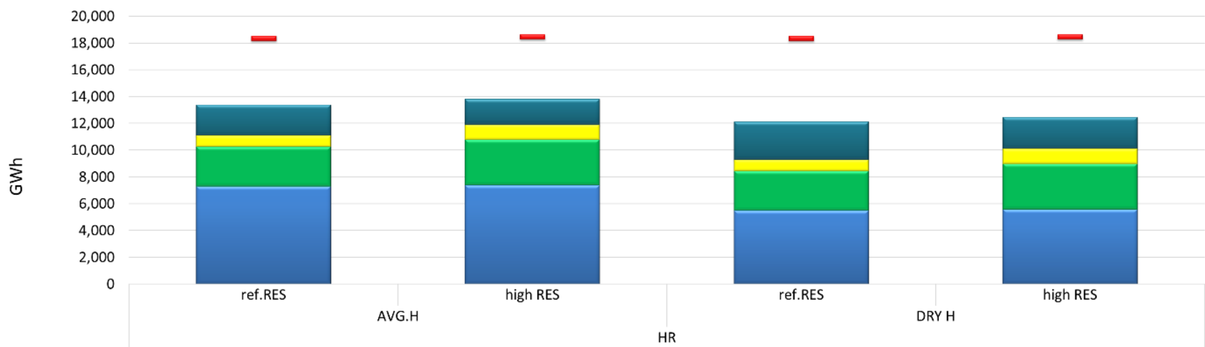
Table 28: PS HPPs generation in IPTO market area – Alternative CO_2 emission tax

Generation from PS HPPs (GWh)	Average hydrological conditions	Dry hydrological 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 hydrological conditions points again to small impact of hydro generation in IPTO market area.

5.2.5. HOPS market area

Generation mix and selected set of indicators, as the main results of market analysis for HOPS market area, are presented in Figure 65 and Figure 66, respectively.



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

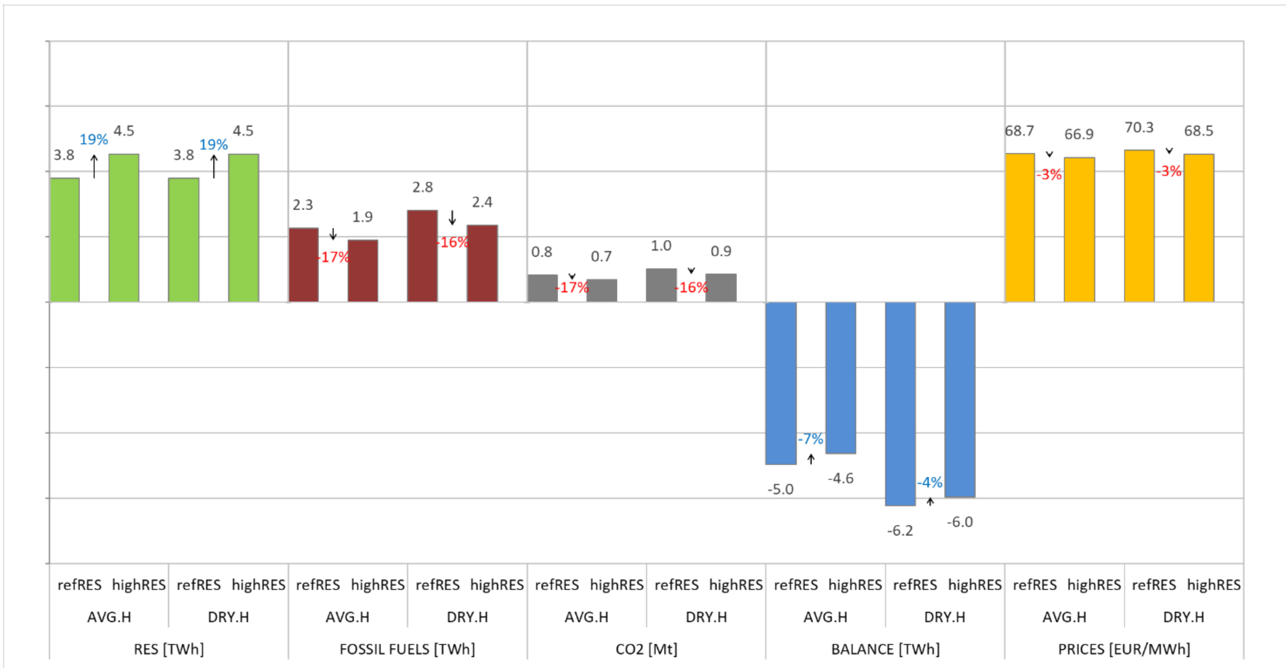


Figure 66: Main system operating indicators in HOPS market area in 2030 - ref. RES vs high RES, dry and average hydrology – Alternative CO_2 emission tax

Considering the generation mix presented in Figure 65, in conjunction with the main system indicators depicted in Figure 66, 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 hydrological conditions:

- RES generation (wind+solar) rise 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.

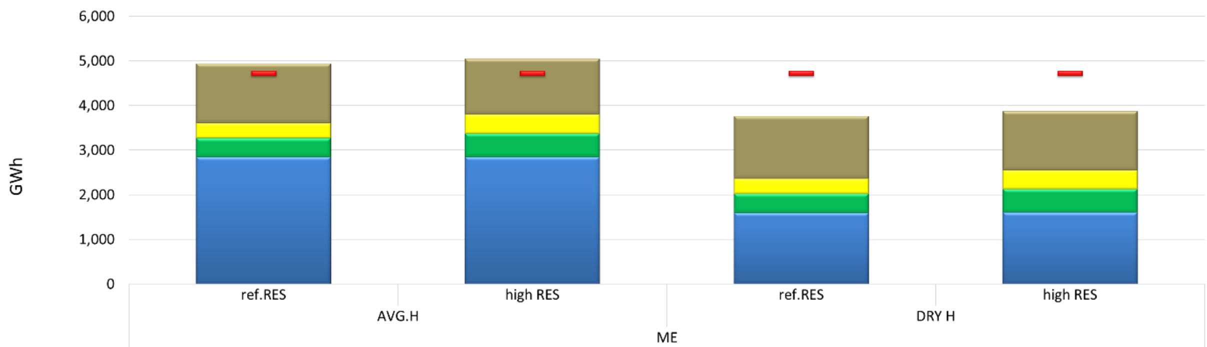
- In HOPS market area total demand in 2030 in average hydrological conditions is mainly supplied by hydro and RES generation (60-64% depending on the level of RES integration). Generation from fossil fuel fired plants is on the level of 2.3 TWh and 1.9 TWh in the case of ref RES and high RES integration, respectively. Dry hydrological 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 hydrological conditions higher level of RES integration lead to a decrease of TPPs generation for about 17%. In correlation to that, emissions of CO_2 have the same trend regarding hydrological conditions and level of RES integration.
- Net import in HOPS market area is between 4.6 and 5.0 TWh (25% and 27% of the area demand) in average hydrological conditions and increases with decrease in generation from HPPs in dry hydrological condition, reaching 33% of total demand.
- Higher RES integration decreases the net import in all hydrological conditions for 4%-7%.
- As a result, greater RES generation in both hydrological conditions leads to a decrease in prices for 3%.
- In comparison to other market areas, engagement of PS HPPs in 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 hydrological conditions	Dry hydrological conditions
Ref. RES	110.3	108.7
High RES	185.2	184.5
Difference	**74.9**	**75.8**

5.2.6. CGES market area

Generation mix and selected set of indicators, as the main results of market analysis for CGES market area, are presented Figure 67 in and Figure 68, 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 67: Generation mix in CGES market area in 2030 - ref. RES vs high RES, dry and average hydrology – Alternative CO_2 emission tax

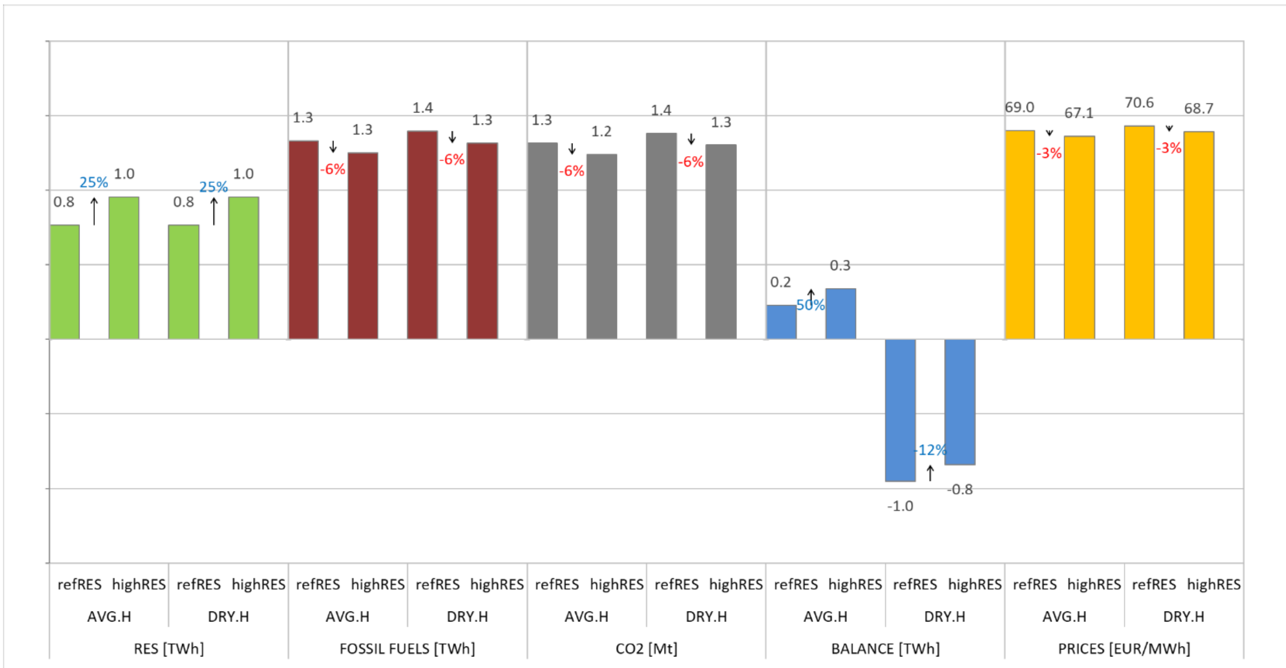


Figure 68: Main system operating indicators in CGES market area in 2030 - ref. RES vs high RES, dry and average hydrology – Alternative CO_2 emission tax

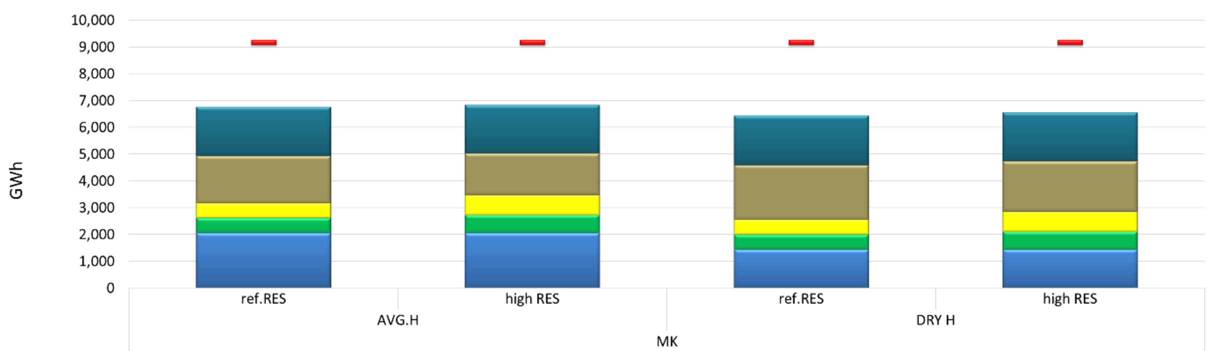
Considering the generation mix and main system indicators presented in the figures above the following conclusions could be drawn:

- CGES market area is the smallest, almost balanced market area in the EMI region.
- RES generation (wind+solar) rise 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 hydrological conditions and small changes in CO_2 emission.

- With higher RES generation, CGES market area increases its net export or decreases its net import, depending on the hydrological conditions.
- In dry hydrological conditions, generation from HPPs is decreased for 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

Generation mix and selected set of indicators, as the main results of market analysis for MEPSO market area, are presented in Figure 69 and Figure 70, respectively.



	ref.RES (AVG.H)	high RES (AVG.H)	ref.RES (DRY H)	high RES (DRY H)
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 69: Generation mix in MEPSO market area in 2030 - ref. RES vs high RES, dry and average hydrology – Alternative CO_2 emission tax

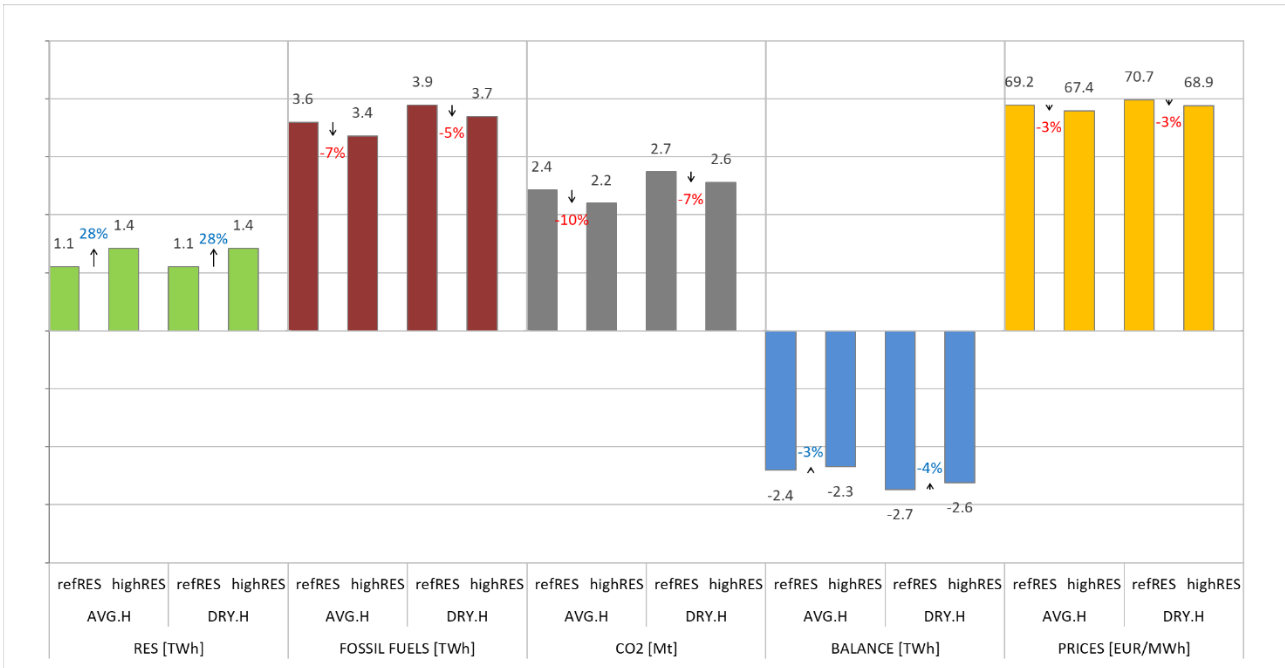


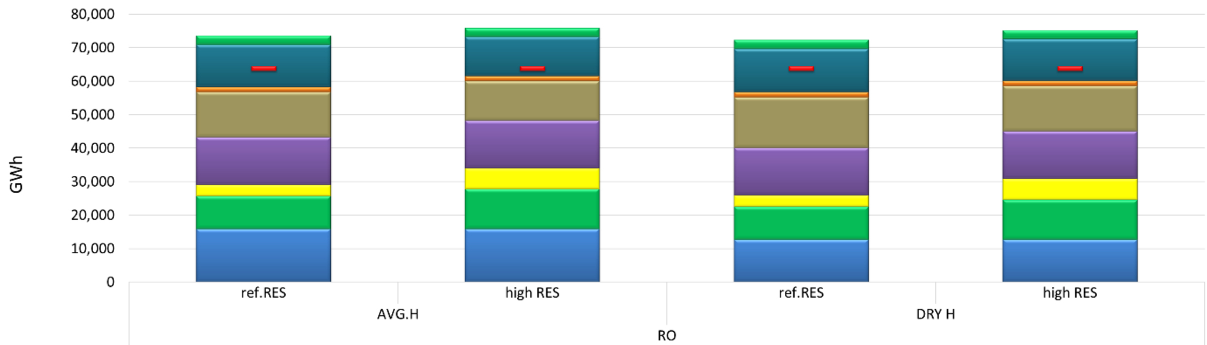
Figure 70: Main system operating indicators in MEPSO market area in 2030 - ref. RES vs high RES, dry and average hydrology – Alternative CO_2 emission tax

Considering the generation mix presented in Figure 69, in conjunction with the main system indicators depicted in Figure 70, 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 hydrological conditions:

- RES generation (wind+solar) rise 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 for 0.24 TWh (-7%) in average hydrological conditions and 0.19 TWh (-5%) in dry hydrological conditions. It can be noted that higher level of RES generation provokes decrease of import (-0.1 TWh), in both hydrological conditions.
- Decrease in fossil fuel fired plants generation decreases the CO_2 emission for 10% and 7 % in average and dry hydrological conditions, respectively.
- Net import slightly decrease with higher RES generation, but in all scenarios MEPSO market area is a net importer.
- As a result, greater RES generation in both hydrological conditions leads to a decrease in prices for 3%.
- In dry hydrological conditions, hydro generation is reduced for 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 hydrological 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

Generation mix and selected set of indicators, as the main results of market analysis for Transelectrica market area, are presented in Figure 71 and Figure 72, 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 71: Generation mix in Transelectrica market area in 2030 - ref. RES vs high RES, dry and average hydrology – Alternative CO_2 emission tax

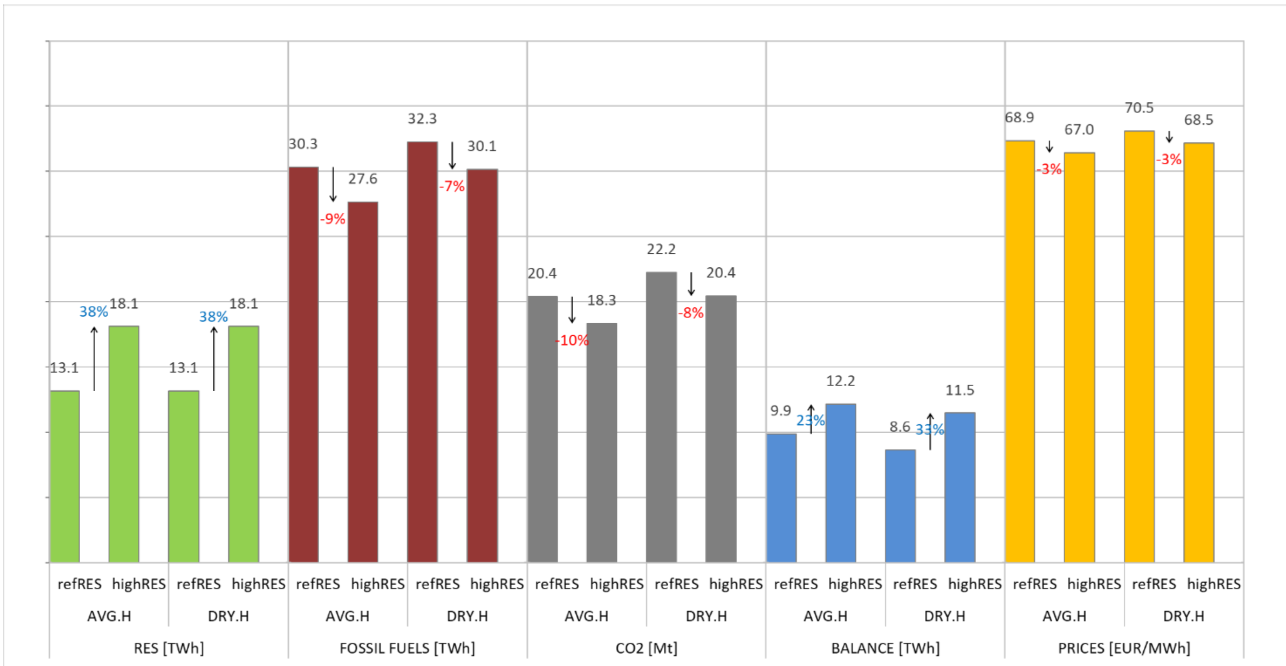


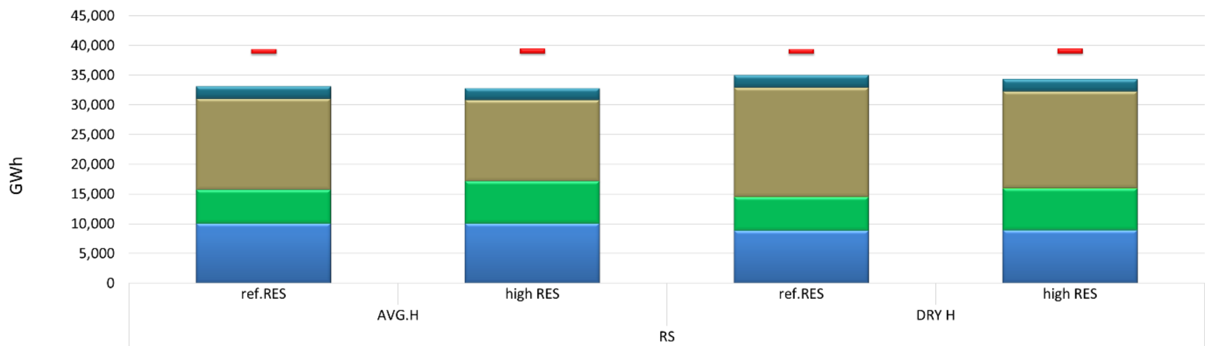
Figure 72: Main system operating indicators in Transelectrica market area in 2030 - ref. RES vs high RES, dry and average hydrology – Alternative CO_2 emission tax

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 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 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 emission for 10% and 8%.
- In dry hydrological conditions, TPPs generation is increased to compensate reduction in HPPs generation. In dry hydrological 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 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 Transelectrica market area rises for 2.3 TWh (23%) in average hydrological conditions. In dry hydrological conditions, this increase is even higher and export increases for 2.8 TWh or 33%.
- Greater RES generation in both hydrological conditions leads to a decrease in prices for 3%. With increased RES generation cheaper power plants become marginal and prices decrease.
- In dry hydrological conditions, hydro generation is reduced for 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 hydrological conditions are higher for 1.6 EUR/MWh

5.2.9. EMS market area

Generation mix and selected set of indicators, as the main results of market analysis for EMS market area, are presented in Figure 73 and Figure 74, respectively.



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

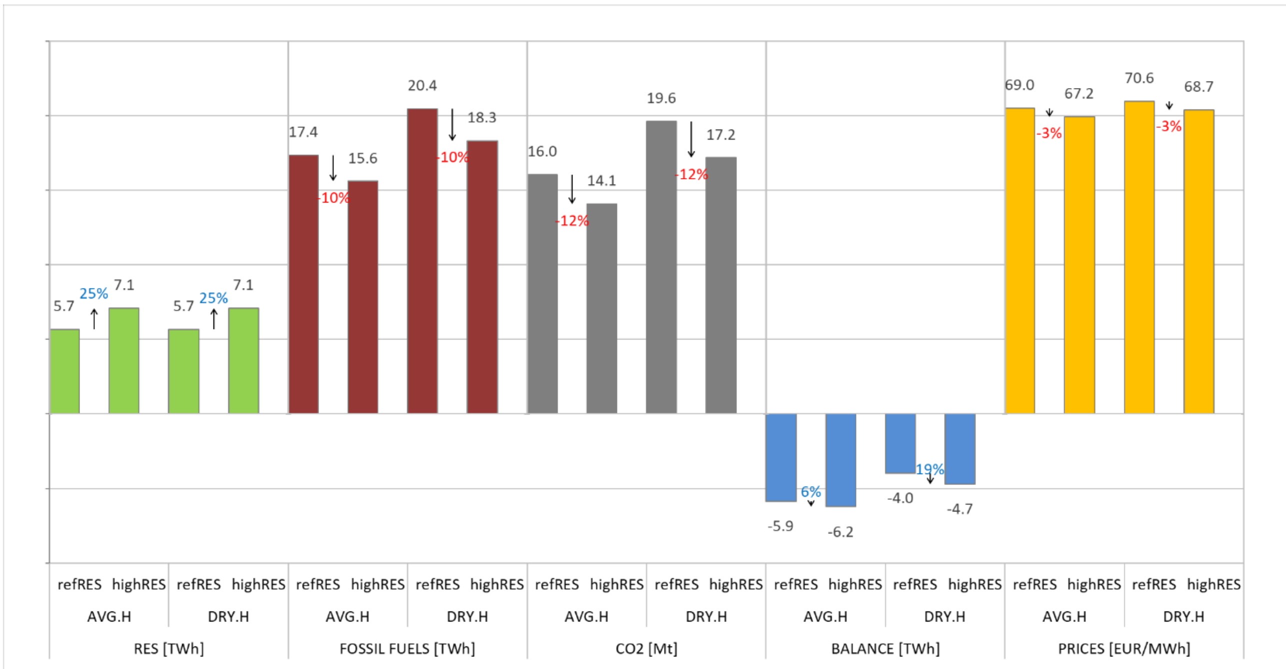


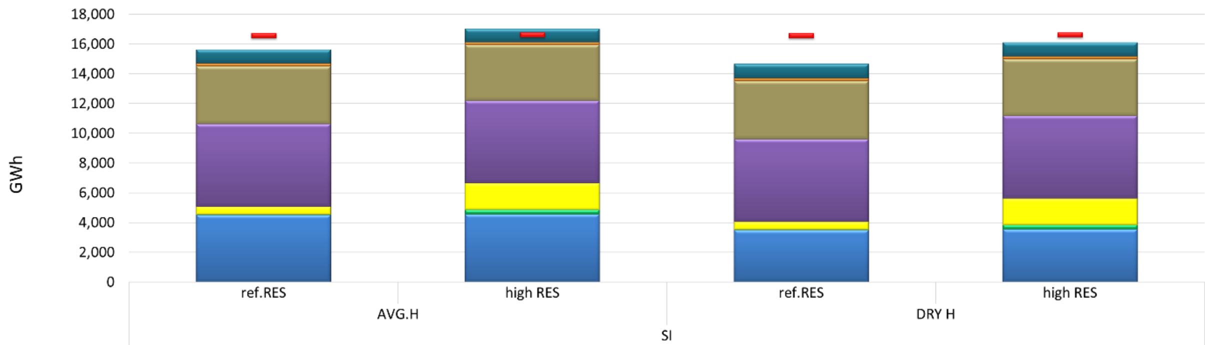
Figure 74: Main system operating indicators in EMS market area in 2030 - ref. RES vs high RES, dry and average hydrology – Alternative CO_2 emission tax

Considering the generation mix presented in Figure 73, in conjunction with the main system indicators depicted in Figure 74, 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 hydrological conditions:

- RES generation (wind+solar) rise 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 emission decreases for 12%.
- At the same time, increased generation from RES implicates an increase in the import of EMS market area for 0.3 TWh (6%) and 0.7 TWh (19%) in the case of average and dry hydrological conditions, respectively.
- As a result, greater RES generation in both hydrological conditions leads to a decrease in prices for 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 pointing to the fact that existing hydropower plants and strong regional connections enables enough flexibility for the given level of RES generation.

5.2.10. ELES market area

Generation mix and selected set of indicators, as the main results of market analysis for ELES market area, are presented in Figure 75 and Figure 76, 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 75: Generation mix in ELES market area in 2030 - ref. RES vs high RES, dry and average hydrology – Alternative CO_2 emission tax

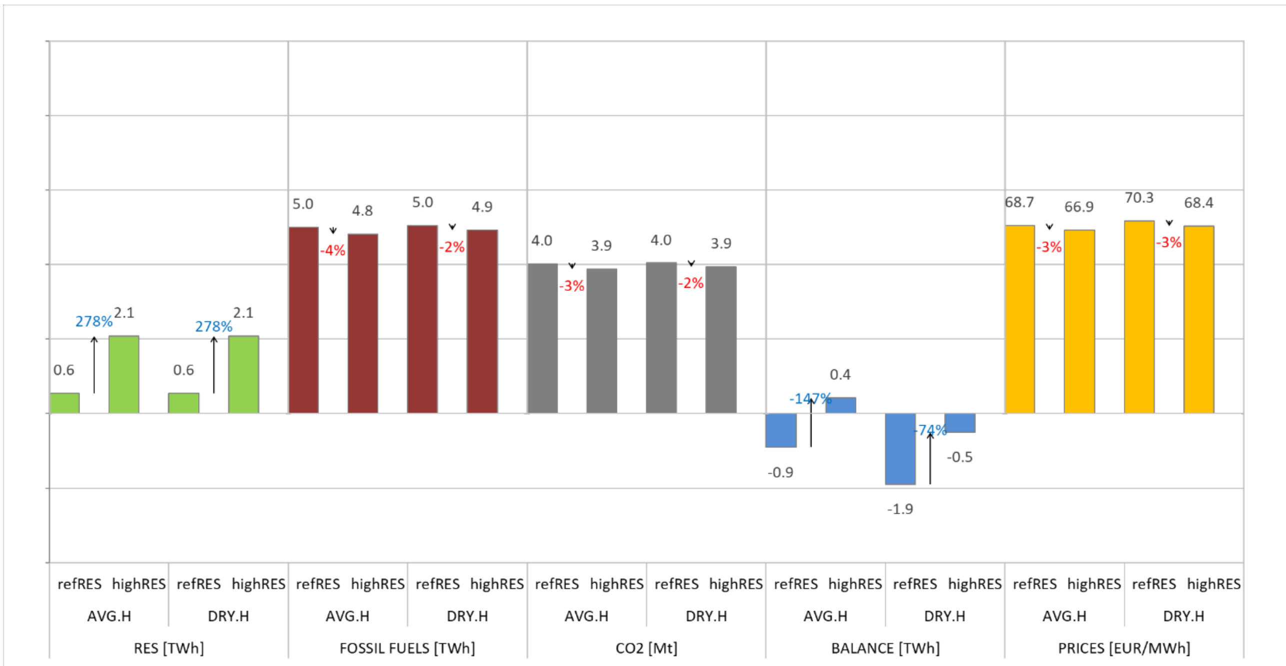


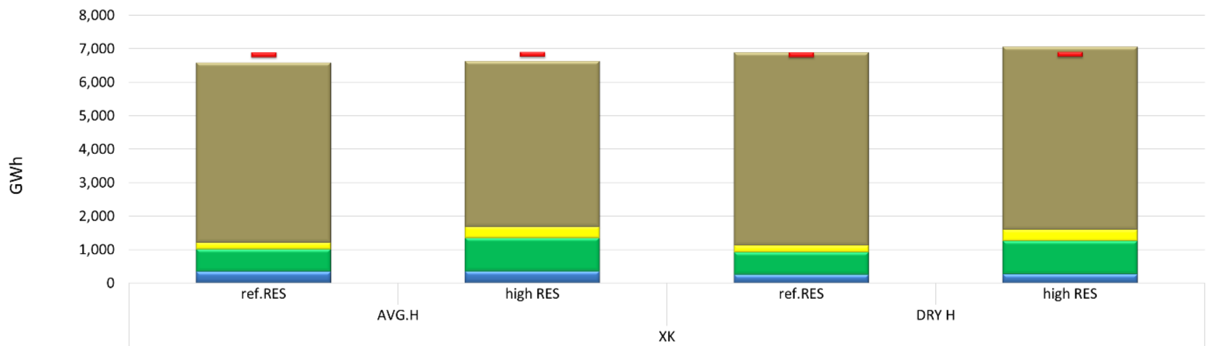
Figure 76: Main system operating indicators in in ELES market area in 2030 - ref. RES vs high RES, dry and average hydrology – Alternative CO_2 emission tax

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

- RES generation (wind+solar) 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 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 hydrological conditions, but with reduced HPPs generation, 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 hydrological conditions, respectively.
- As a result, greater RES generation in both hydrological conditions leads to a decrease in prices for 3%. Namely, with increase in RES generation cheaper power plants become marginal.
- Simulations shows that engagement of PS HPP is very small pointing to the fact that existing hydropower plants and strong regional connections enables enough flexibility for the given level of RES generation.

5.2.11. KOSTT market area

Generation mix and selected set of indicators, as the main results of market analysis for the KOSTT market area, are presented in Figure 77 and Figure 78, 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	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 77: Generation mix in KOSTT market area in 2030 - ref. RES vs high RES, dry and average hydrology – Alternative CO_2 emission tax

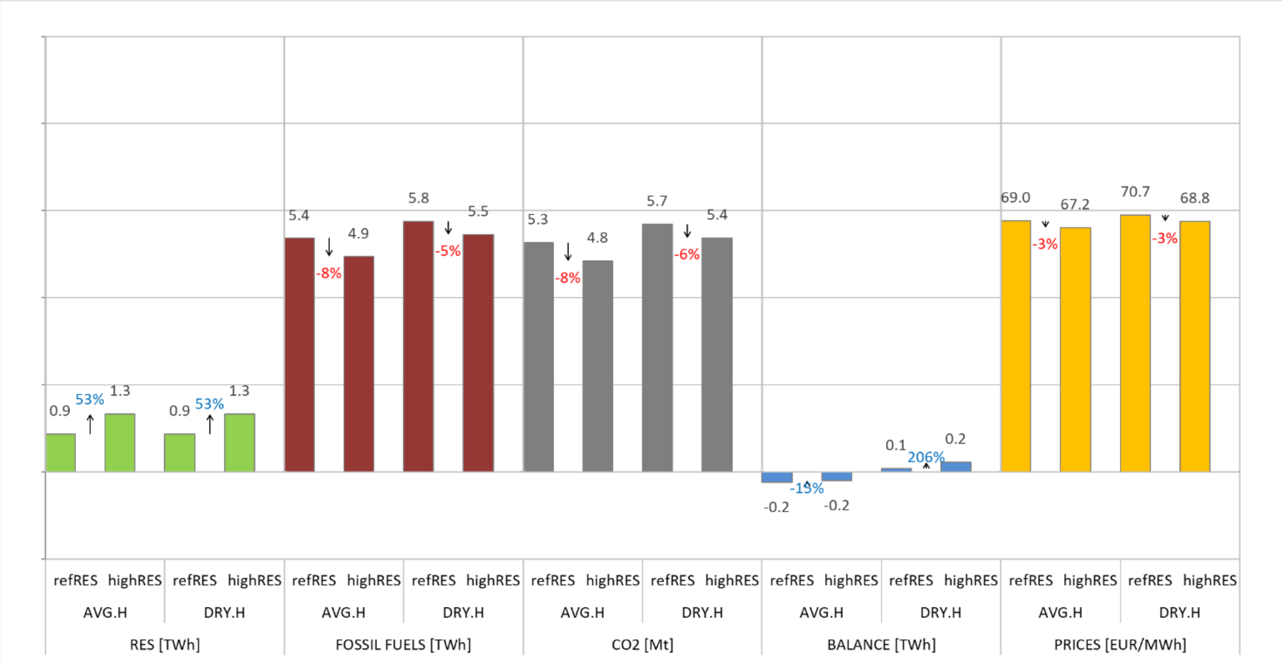


Figure 78: Main system operating indicators in KOSTT market area in 2030 - ref. RES vs high RES, dry and average hydrology – Alternative CO_2 emission tax

Considering the generation mix presented in Figure 77, in conjunction with the main system indicators depicted in Figure 78, 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 hydrological conditions:

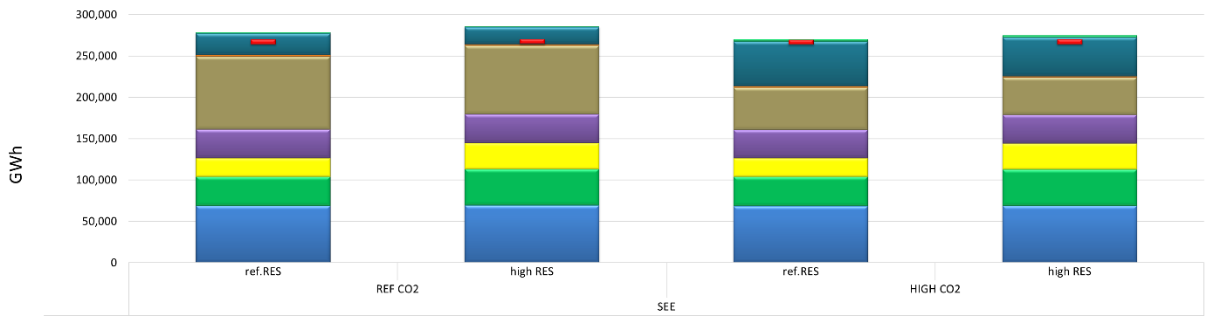
- RES generation (wind+solar) rise from 0.9 TWh to 1.3 TWh (+53%) supplying between 13% and 20% of area demand.
- Higher RES generation leads to fossil fuels fired TPPs generation reduction of about 0.3-0.5 TWh (5-8%), depending on hydrological conditions, and decrease in CO_2 emission is proportional.
- KOSTT market area is almost balanced in this group of scenarios. In the case of the average hydrological conditions this market area imports about 0.2 TWh and 0.23 TWh in increased and referent level of RES generation, respectively. In dry hydrological conditions TPPs are competitive enough to compensate reduction from hydro generation and to convert 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 hydrological conditions leads to a decrease in prices for 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 pointing to the fact that existing hydropower plants and strong regional connections enables 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 hydrological conditions have been set and kept constant in the following 4 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 CO_2 emission tax and referent level of RES integration
4. Alternative CO_2 emission tax and high level of RES integration

It can be noted that this group of scenarios combines to some extend conditions from previous two groups of scenarios. In this group of scenarios impact of different levels of CO_2 emission tax, together with levels of RES integration is in focus. Generation mix for the whole EMI region is presented in Figure 79 while main indicators are given in Figure 80.



SEE	REF CO2 ref.RES	REF CO2 high RES	HIGH CO2 ref.RES	HIGH CO2 high RES
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 79: Generation mix in EMI region in 2030 - ref. RES vs high RES, ref. and high CO_2 emission tax

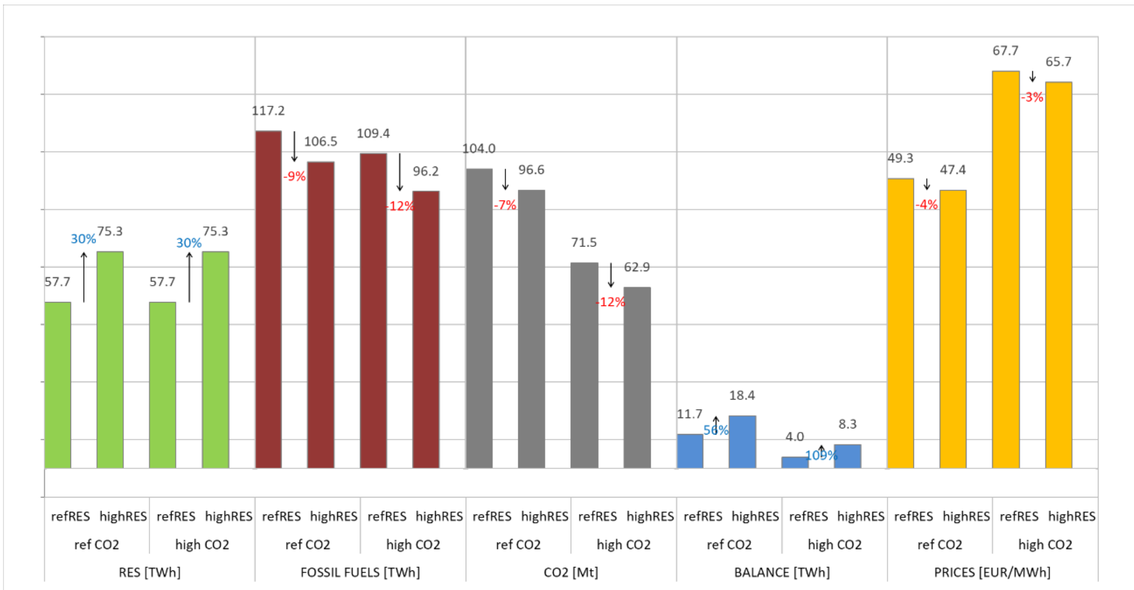


Figure 80: Main system operating indicators in EMI region in 2030 - ref. RES vs high RES, ref. and high CO_2 emission tax

The above given figures come out with the following conclusions:

- **In the case of slower demand growth, main technology in 2030 in case of ref. CO_2 emission tax is lignite and it supplies about 33% of the load, followed by HPPs which supply 26% of the load.** 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 dominant source of power supply (26%), followed by the wind and solar energy (22%-28%, depending on the level of RES integration). The share of lignite is decreased to a level of 17-19%, while the share of gas based TPPs is increased to a level of 18-20% of the load, depending on the level of RES integration.

  This change in main technology that supplies the load in EMI region in 2030 is fully in line with changes previously described for referent load cases.

- Hydro and RES technologies, which can be considered as "green" technologies, become main technologies in EMI region in 2030 and supply between 47% and 54% of total demand.

- As in the case of previous groups od scenarios, RES generation increases from 57.7 TWh (in ref. RES scenario) to 75.3 TWh in high RES scenario which is the increase of 30% (Figure 80). Increase per market areas (Figure 81) is between 0.2 and 6 TWh (in CGES and IPTO market areas) or between 19% and 278% (in HOPS and ELES market areas respectively).

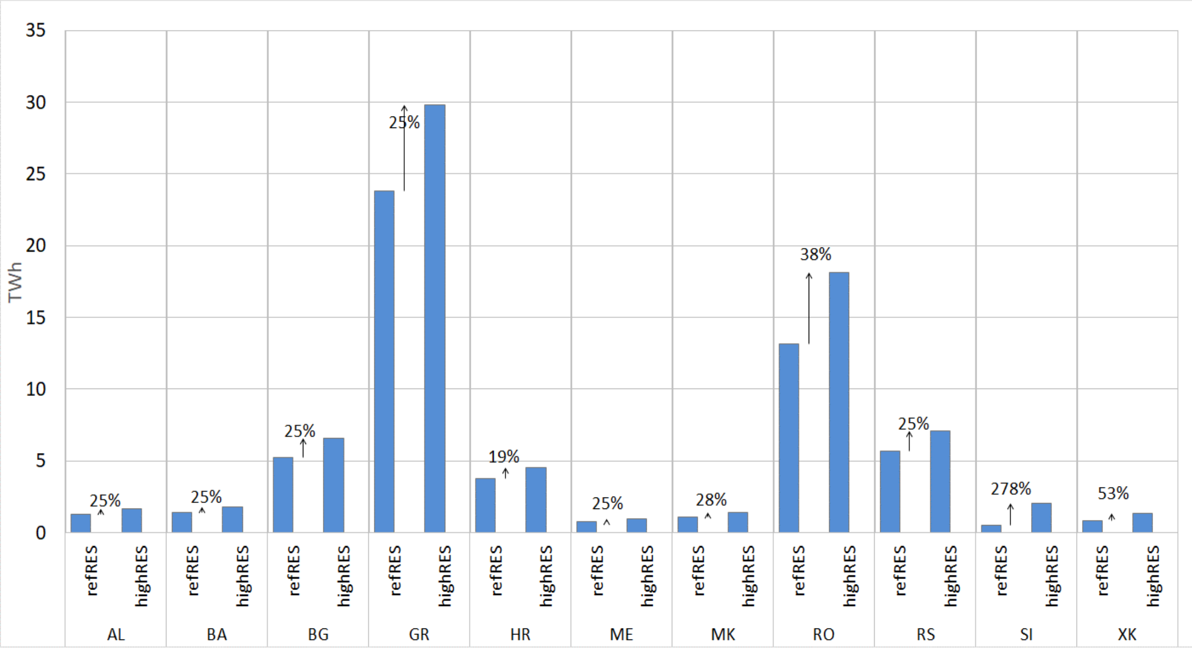


Figure 81: RES generation in 2030 - ref. RES vs high RES

- **Higher level of CO_2 emission tax implicates reduction in total TPPs generation. However, the main source of that reduction is decrease in generation from lignite fired plants which have greater CO_2 emission factors. Compared to Ref. CO_2 scenarios, the lignite fired plants reduced generation in High CO_2 price scenarios by 37-38 TWh (-42% – -46%), depending on the level of RES integration.** Taking into account that hydro and RES generation are stable, gas TPPs generation, which remain competitive since electricity prices on neighboring markets are also higher in the scenarios with high CO_2 price, is increased in order to compensate reduction of generation from lignite fired plants. In general, gas TPPs have lower CO_2 emission factor and their marginal price is lower than lignite TPPs in case with high CO2 tax. This fact enables increase in generation from gas TPPs for 28 TWh (+106%) and 26 TWh (+126%) in ref. RES and high RES generation, respectively. Bottom line, high CO2 price provokes decrease of generation in fossil fuel powered plants for 8 TWh (-6.7%) to 10 TWh (-9.6%), depending on the level of RES generation. **At the same time CO_2 emissions decreases for 33 Mt (-31 %) and 34 Mt (-35%) in ref. RES and high RES generation, respectively.**
- Increase in CO_2 emission tax implicates decrease in fossil fuel powered plants generation. However, significant change can be noted in generation mix between lignite and gas fired plants. 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 caused by significant increase in gas TPPs generation in two biggest market areas - IPTO and Transelectrica market areas. In IPTO market area only gas fired plants exist in 2030 which increase generation for 16 TWh or 96%. In Transelectrica market area relative increase in gas TPPs generation is even higher and amount 121%, while in absolute terms this increase is around 7 TWh. However, in Transelectrica market area total generation from fossil fuel powered plants is decreased for 1.3 TWh which is the consequence of reduction in lignite generation for 40%. **The sharpest decrease in TPPs generation is in case of NOSBiH market area, where lignite TPPs generation is reduced for 8.2 TWh or over 96%.**

In all other areas, decrease in lignite and increase in gas TPPs can be seen (Figure 82).

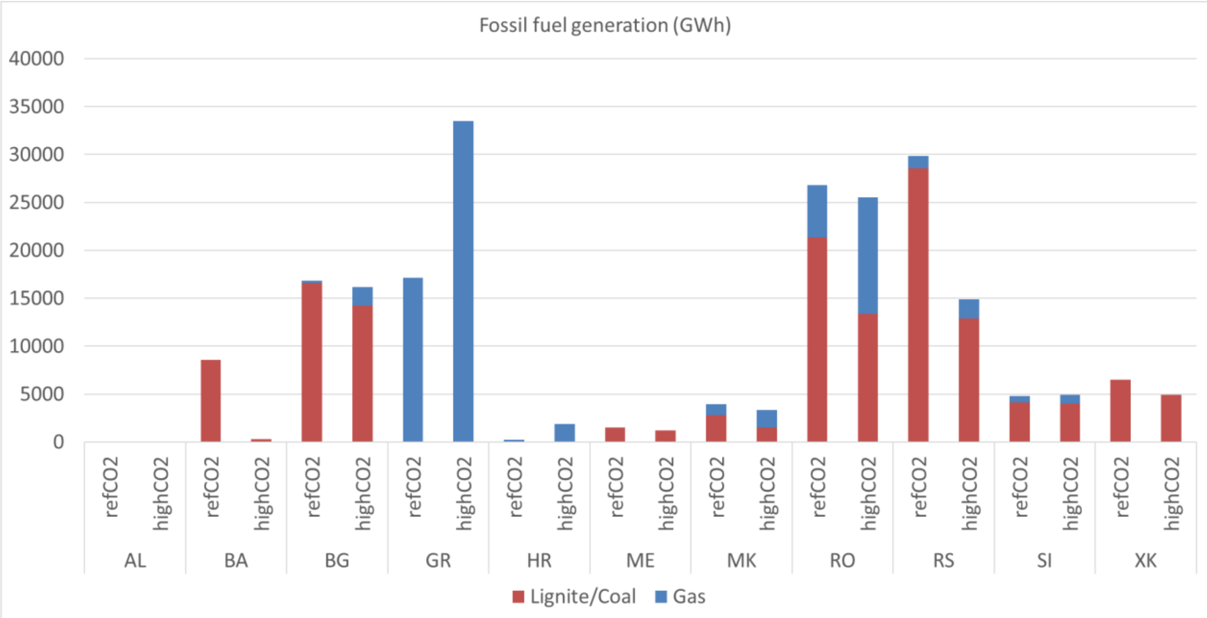


Figure 82: Fossil fuel powered plants generation in 2030 - ref. CO2 vs high CO2, referent RES integration

- **EMI region is a net exporter in 2030 with export between 4 TWh and 18.4 TWh or between 1.5% and 6.9% of total demand in all scenarios.** High CO_2 emission tax provokes decrease in the net export of EMI region for 8-10 TWh, but still, due to slower demand growth, EMI region even in the cases of high CO_2 prices remain net exporter in 2030.
- **Changes in balance positions for all market zones in referent RES scenario (Figure 83) shows that in almost all countries where lignite powered plants have significant share in generation mix, export is reduced, or zone even become net importer (KOSTT, NOSBiH and EMS markets areas), due to increased CO_2 emission tax. Market areas where gas powered plants have bigger impact on generation mix, export increases (Transelectrica market area) or import decreases (HOPS market area). IPTO market area, due to significant generation capacities in gas technology becomes net exporter.**

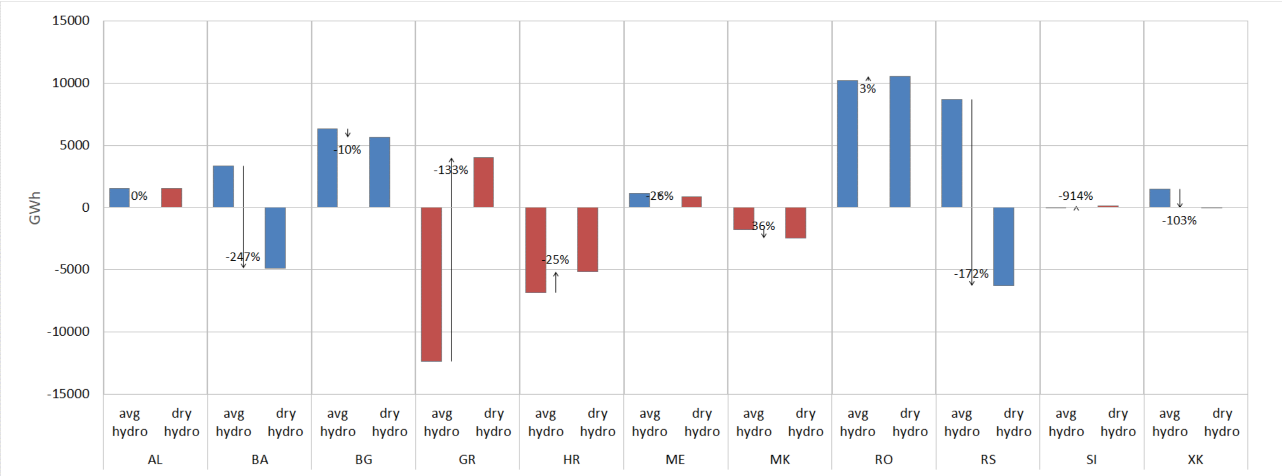


Figure 83: Balance positions per market areas in 2030 - ref. CO2 vs high CO2, referent RES integration

- **Average regional wholesale market prices (Figure 80) are between 47.4 and 67.7 EUR/MWh with decrease provoked by high RES integration of around 2 EUR/MWh or 3-4% in both levels of CO_2 emission tax. From the same figure it could be seen that WM prices in case of high CO_2 emission tax would be higher for around 18 EUR/MWh or 38%.**

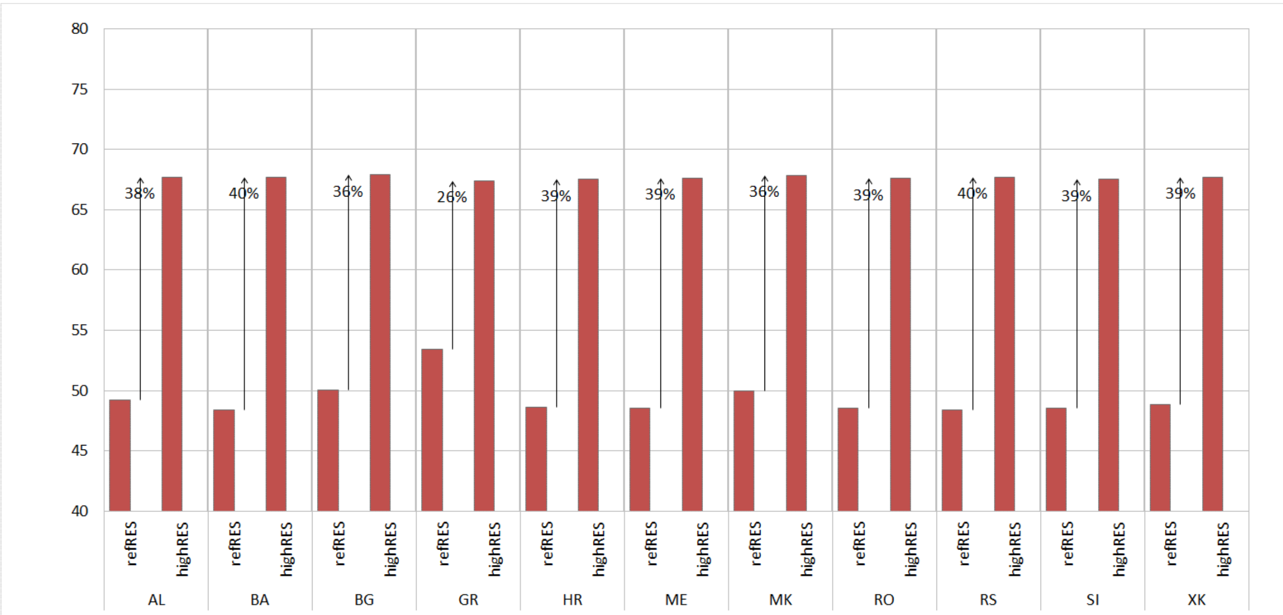
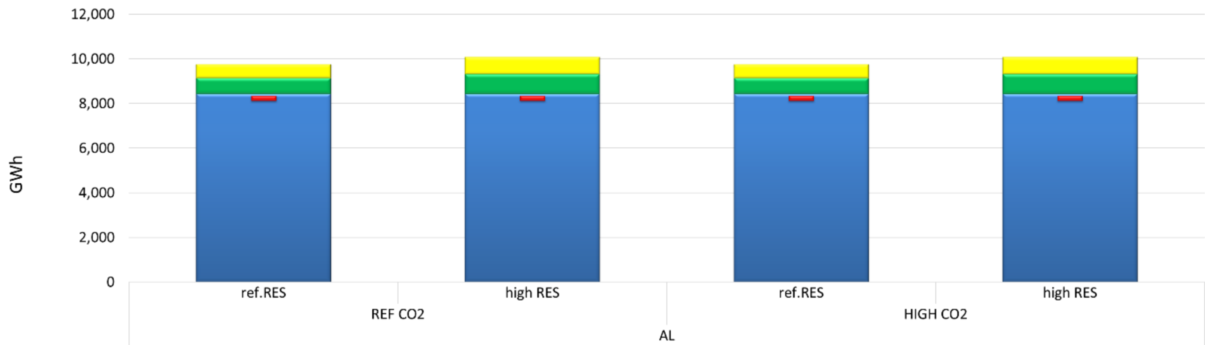


Figure 84: Prices in EMI region in 2030 - ref. CO2 vs high CO2, referent RES integration

From Figure 84 it could be seen that electricity prices are evenly distributed across the EMI region without significant deviations from average price on regional level, especially in the case of high CO_2 emission tax. Some deviations can be noted in ref. CO_2 tax level, where the highest wholesale market price is in IPTO market area, as a big importing area. In all other market areas high level of CO_2 emission tax provokes increase in wholesale market prices for about 36-40%, compared to ref. CO_2 price level.

5.3.1. OST market area

Generation mix and selected set of indicators, as the main results of market analysis for OST market area, are presented in Figure 85 and Figure 86, 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	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 85: Generation mix in OST market area in 2030 - ref. RES vs high RES, ref. CO2 and high CO2 emission tax

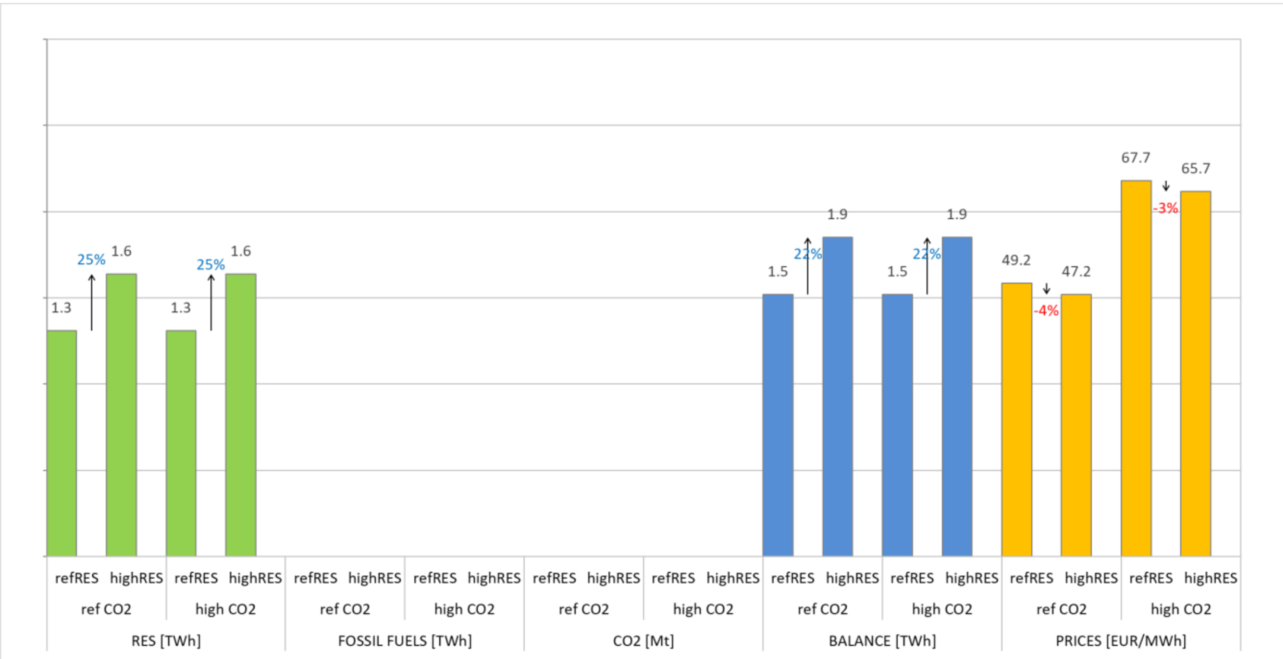


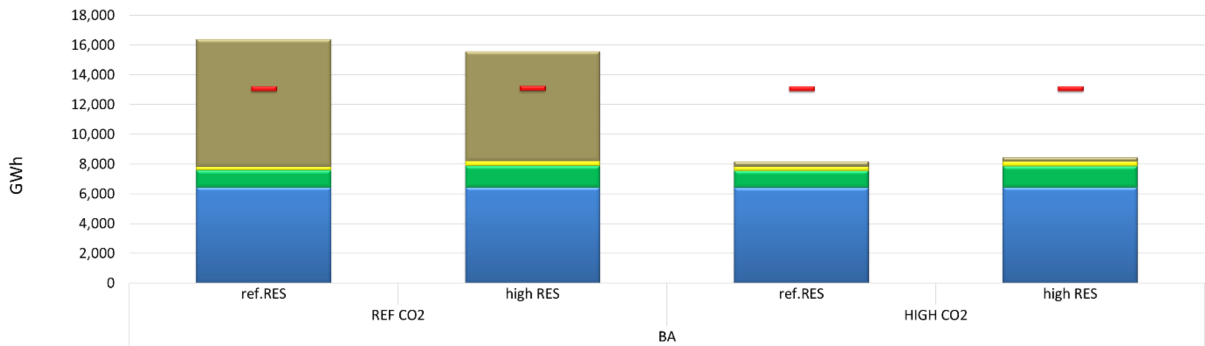
Figure 86: Main system operating indicators in OST market area in 2030 - ref. RES vs high RES, ref. CO2 and high CO2 emission tax

Considering the generation mix presented in Figure 85, in conjunction with the main system indicators depicted in Figure 86, 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 OST market area is characterized with high hydro generation, its operation strongly depends on hydrological 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 for 18 EUR/MWh.

5.3.2. NOSBIH market area

Generation mix and selected set of indicators, as the main results of market analysis for NOSBIH market area, are presented in Figure 87 and Figure 88, 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 87: Generation mix in NOSBIH market area in 2030 - ref. RES vs high RES, ref. CO2 and high CO2 emission tax

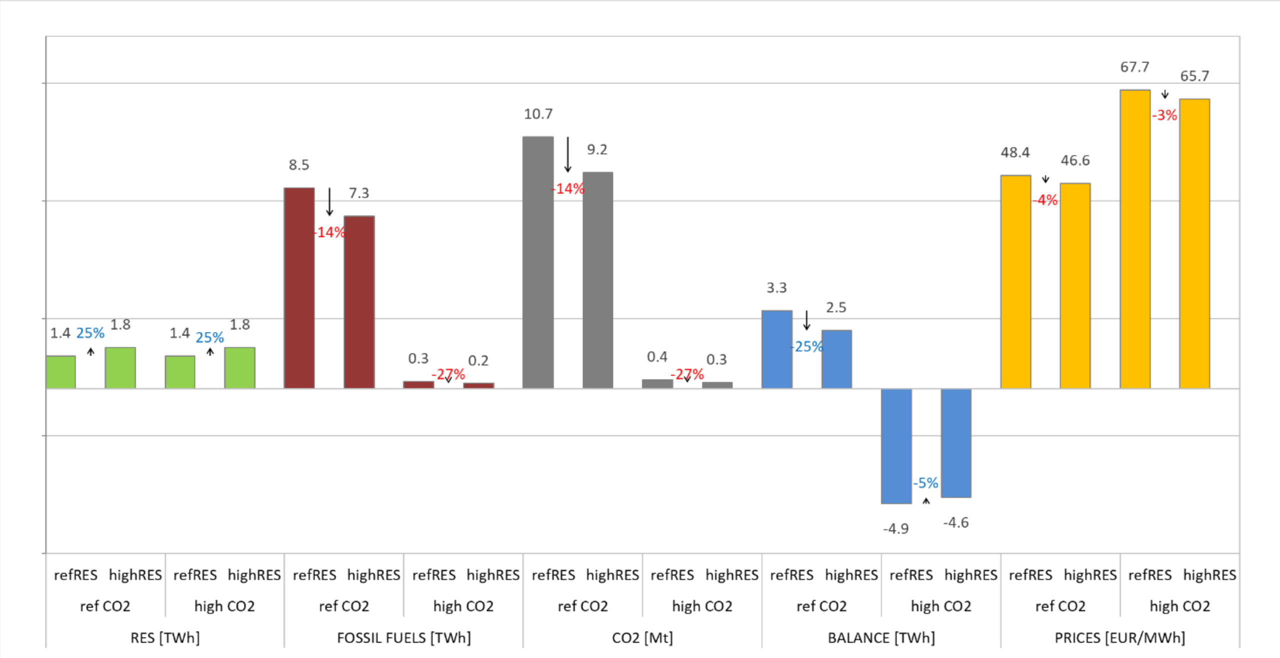


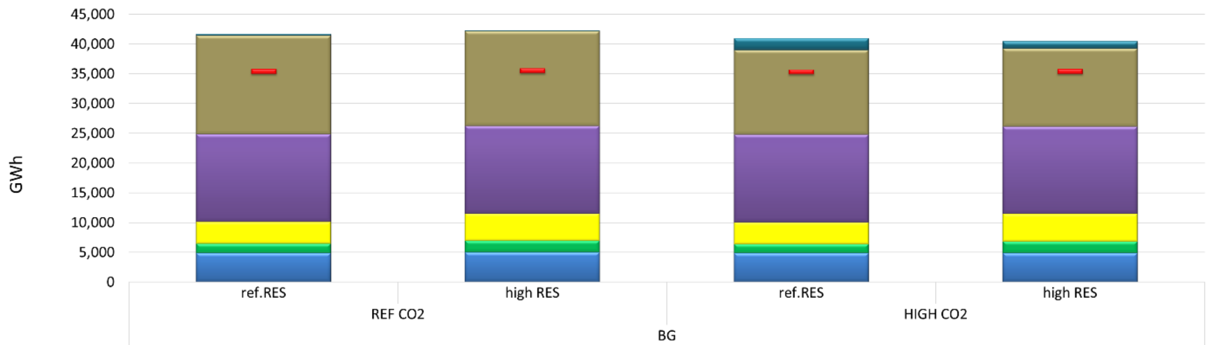
Figure 88: Main system operating indicators in NOSBIH market area in 2030 - ref. RES vs high RES, ref. CO2 and high CO2 emission tax

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

- RES generation (wind+solar) rise from 1.4 TWh to 1.8 TWh (+25%) supplying 11%-14% of the area demand.
- Higher CO_2 emission tax leads to reduction of generation from lignite fired power plants for about 96%, i.e. 7-8 TWh, depending on the level of RES generation. This decrease in TPPs generation leads to a decrease of CO_2 emission for the same levels.
- Higher RES generation also leads to reduction of generation from lignite fired plants between 14% (-1.2 TWh) and 27% (-0.1 TWh) in ref. CO_2 and high CO_2 price levels, respectively. This decrease in TPPs generation leads to a decrease of CO2 emission for the same levels.
- With small increase in RES generation (0.3 TWh) and reduction in TPPs generation (-1.2 TWh), NOSBIH market area decreases net export for around 0.8 TWh or 25% in case of Ref. CO_2 price level. However, with high CO_2 price level, NOSBIH market area becomes net importer with a net import of 4.9 and 4.6 TWh in Ref. RES and High RES generation, respectively. The reason for this lies in the fact that, with high CO_2 price level lignite fired plants from NOSBIH area become less competitive.
- Higher level of CO2 emission tax leads to an increase of wholesale market price by 40% in this market area. In addition, greater generation from RES provokes decrease in market price for about 2 EUR/MWh or 3-4%.
- Simulations shows that engagement of PS HPP is very small pointing to the fact that existing hydropower plants and strong regional connections enables enough flexibility for the given level of RES generation.

5.3.3. ESO EAD market area

Generation mix and selected set of indicators, as the main results of market analysis for ESO EAD market area, are presented in Figure 89 and Figure 90, respectively.



BG	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 89: Generation mix in ESO EAD market area in 2030 - ref. RES vs high RES, ref. CO2 and high CO2 emission tax

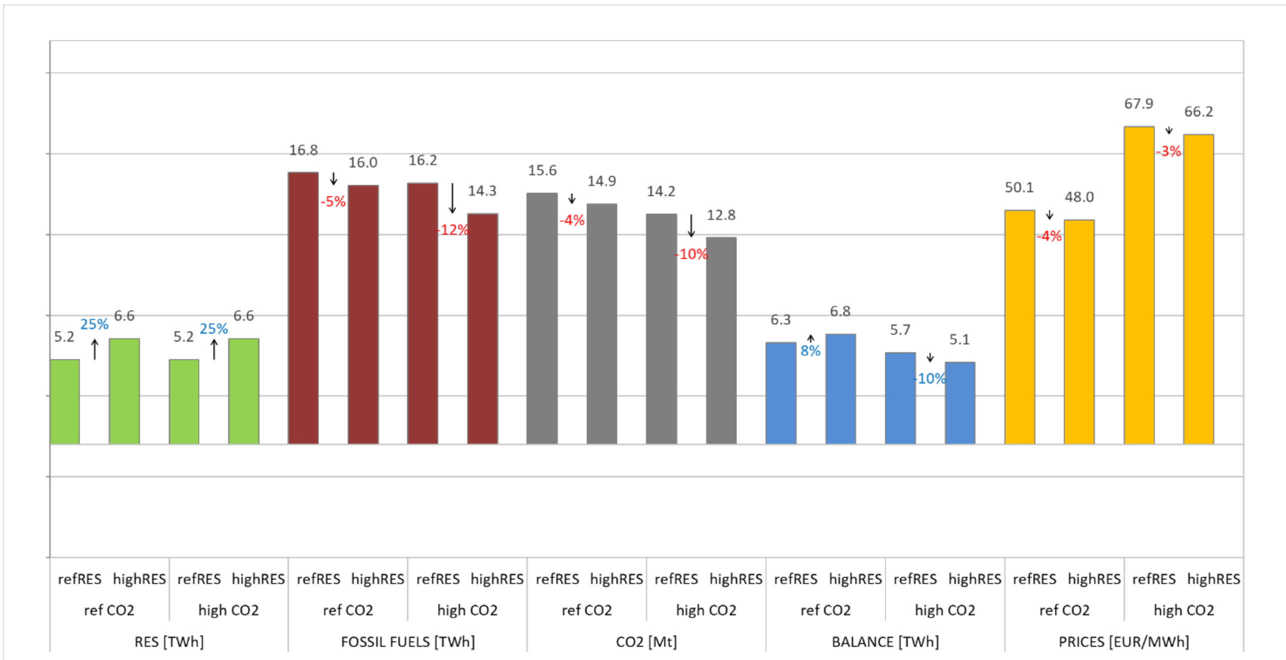


Figure 90: Main system operating indicators in ESO EAD market area in 2030 - ref. RES vs high RES, ref. CO2 and high CO2 emission tax

Considering the generation mix presented in Figure 89, in conjunction with the main system indicators depicted in Figure 90, the following conclusions could be drawn about the operation of this market area:

- RES generation (wind+solar) rise 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 for 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 for 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 for 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 for 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 for 0.5 TWh (8%), while in the case of high CO_2 price level, increase in RES generation leads to a reduction of export for 0.6 TWh (10%).
- As a result, higher level of CO_2 prices provokes increase in wholesale market price for about 36%, while RES generation in both levels of CO_2 prices leads to a decrease in prices for 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.

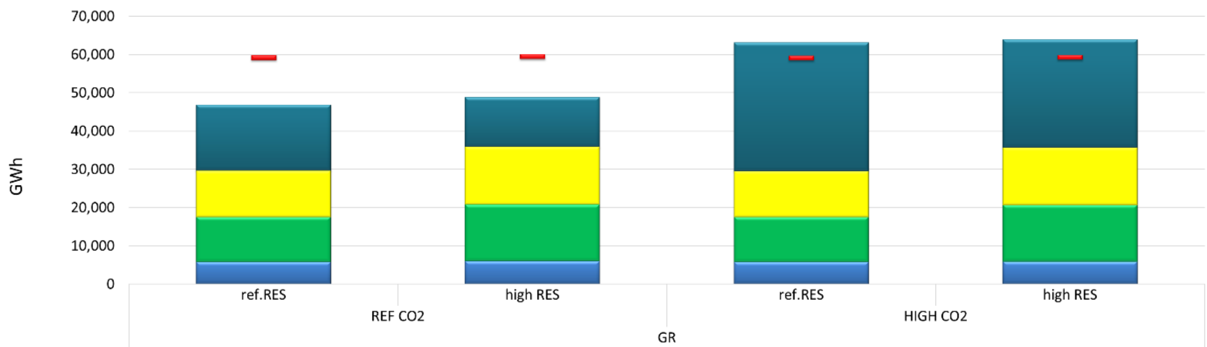
Table 30: PS HPPs generation in ESO EAD market area – Low demand growth

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

Generation mix and selected set of indicators, as the main results of market analysis for IPTO market area, are presented in Figure 91 and Figure 92, respectively.



	REF CO2 ref.RES	REF CO2 high RES	HIGH CO2 ref.RES	HIGH CO2 high RES
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 91: Generation mix in IPTO market area in 2030 - ref. RES vs high RES, ref. CO2 and high CO2 emission tax

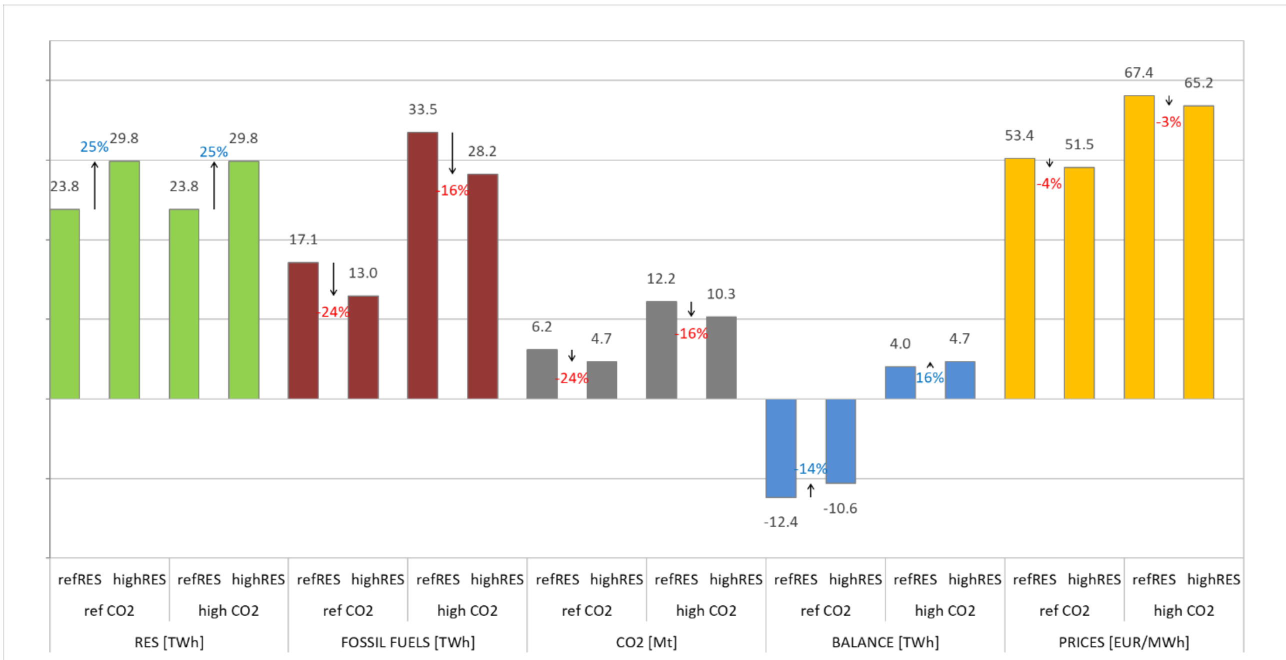


Figure 92: Main system operating indicators in IPTO market area in 2030 - ref. RES vs high RES, ref. CO2 and high CO2 emission tax

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

- Beside Transelectrica market area, 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 emission as well as in export and import in 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 for 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 emission 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, IPTO market area becomes net exporter of 4 to 4.7 TWh.
- Higher RES generation decreases net import for 1.8 TWh and increases net export for 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 for 26%, which is the lowest increase in market price in the EMI region.
- Greater RES generation leads to a decrease in prices for 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).

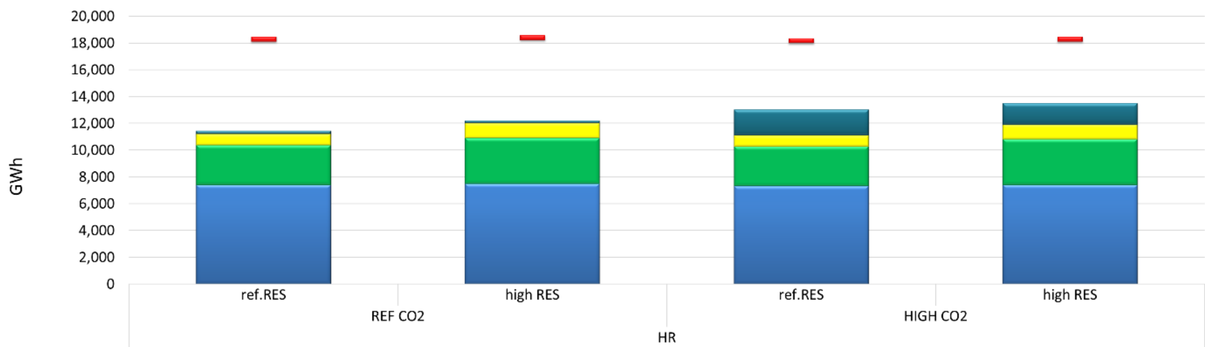
Table 31: PS HPPs generation in IPTO market area – Low demand growth

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

Generation mix and selected set of indicators, as the main results of market analysis for HOPS market area, are presented in Figure 93 and Figure 94, respectively.



	ref.RES (REF CO2)	high RES (REF CO2)	ref.RES (HIGH CO2)	high RES (HIGH CO2)
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 93: Generation mix in HOPS market area in 2030 - ref. RES vs high RES, ref. CO2 and high CO2 emission tax

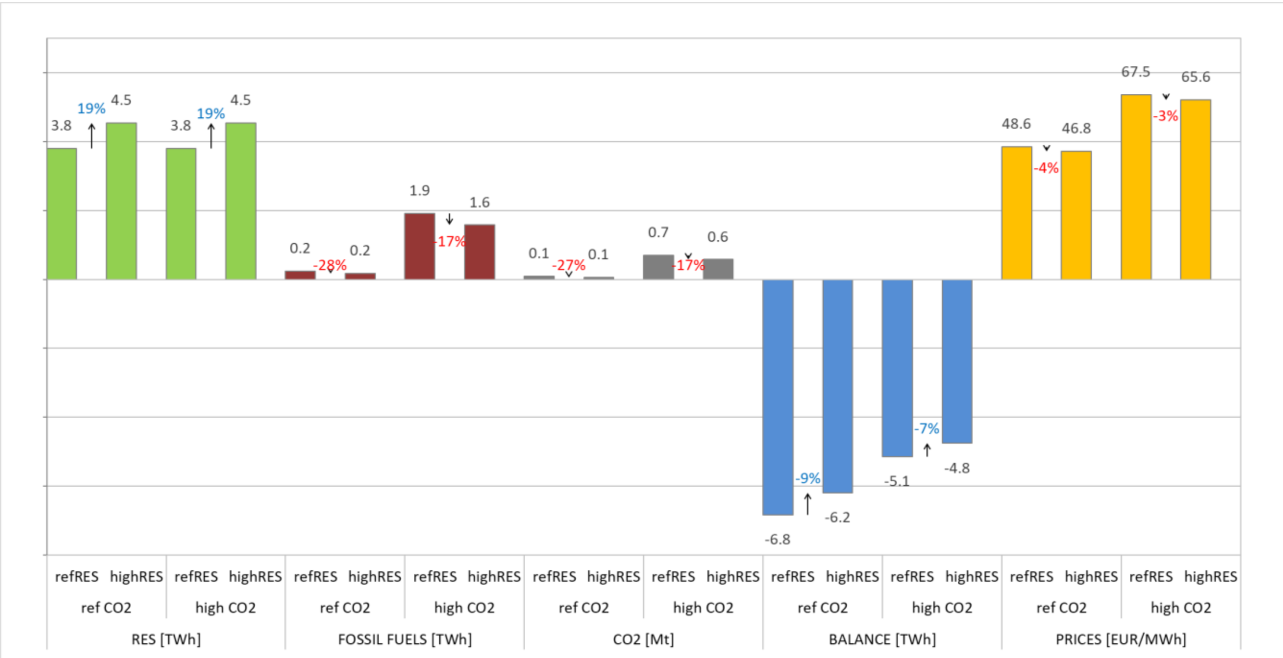


Figure 94: Main system operating indicators in HOPS market area in 2030 - ref. RES vs high RES, ref. CO2 and high CO2 emission tax

Considering the generation mix presented in Figure 93, in conjunction with the main system indicators depicted in Figure 94, 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 for 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.

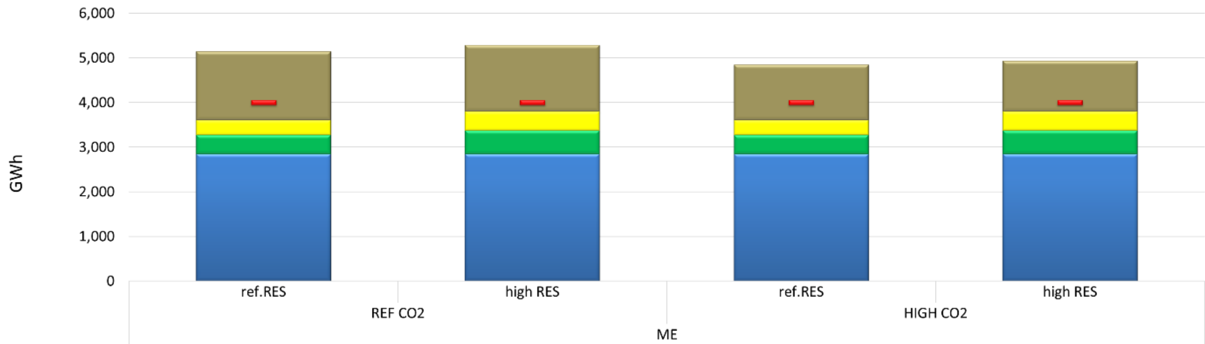
- RES generation (wind+solar) rise from 3.8 TWh to 4.5 TWh (+19%), which is the lowest increase in percentages in the region. This level of RES generation supplies between 21% and 25% of area demand, which is close to regional average.
- In HOPS market area total demand in 2030 is mainly supplied by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

Generation mix and selected set of indicators, as the main results of market analysis for CGES market area, are presented Figure 67 in and Figure 68, 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	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 95: Generation mix in CGES market area in 2030 - ref. RES vs high RES, ref. CO_2 and high CO_2 emission tax

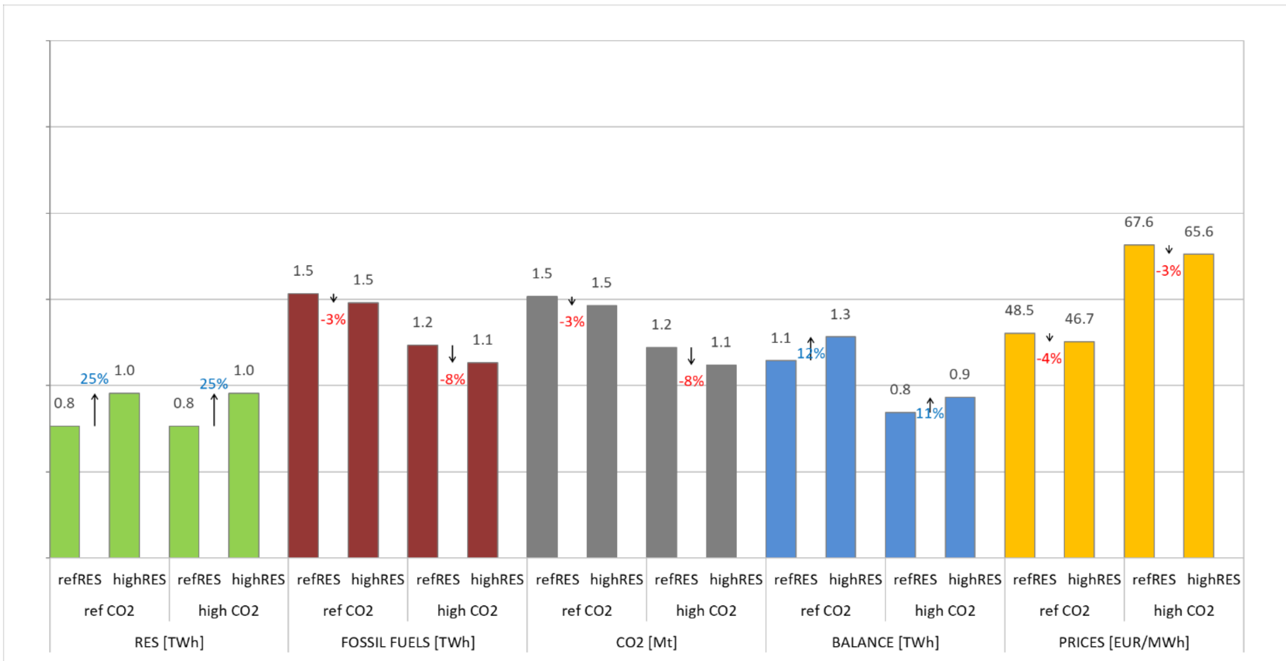


Figure 96: Main system operating indicators in CGES market area in 2030 - ref. RES vs high RES, ref. CO_2 and high CO_2 emission tax

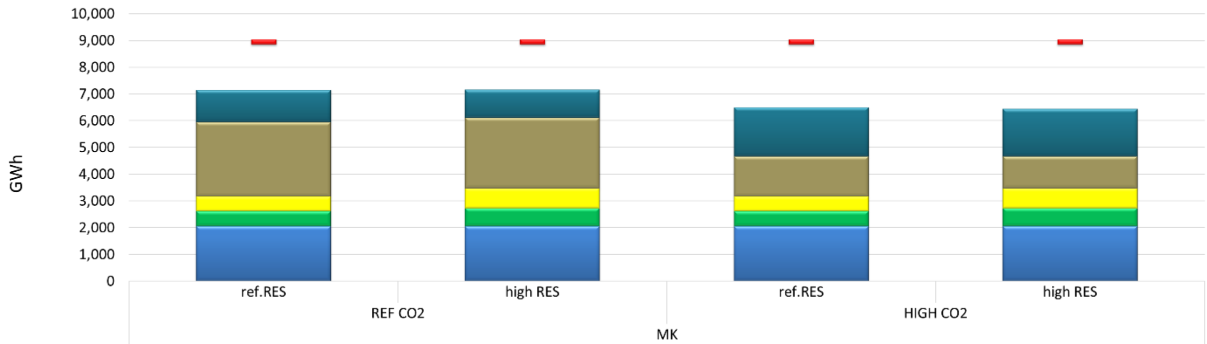
Considering the generation mix and main system indicators presented in the figures above the following conclusions could be drawn:

- 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 for -0.3 to -0.35 TWh, depending on RES generation.
- In general, with higher RES generation, CGES market area increases its net export.
- Wholesale market prices rises with higher level of CO_2 emission tax for about 39%. In addition, increase in RES generation provokes decrease of prices for 3-4%.

5.3.7. MEPSO market area

Generation mix and selected set of indicators, as the main results of market analysis for MEPSO market area, are presented in Figure 97 and Figure 98, 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 97: Generation mix in MEPSO market area in 2030 - ref. RES vs high RES, ref. CO_2 and high CO_2 emission tax

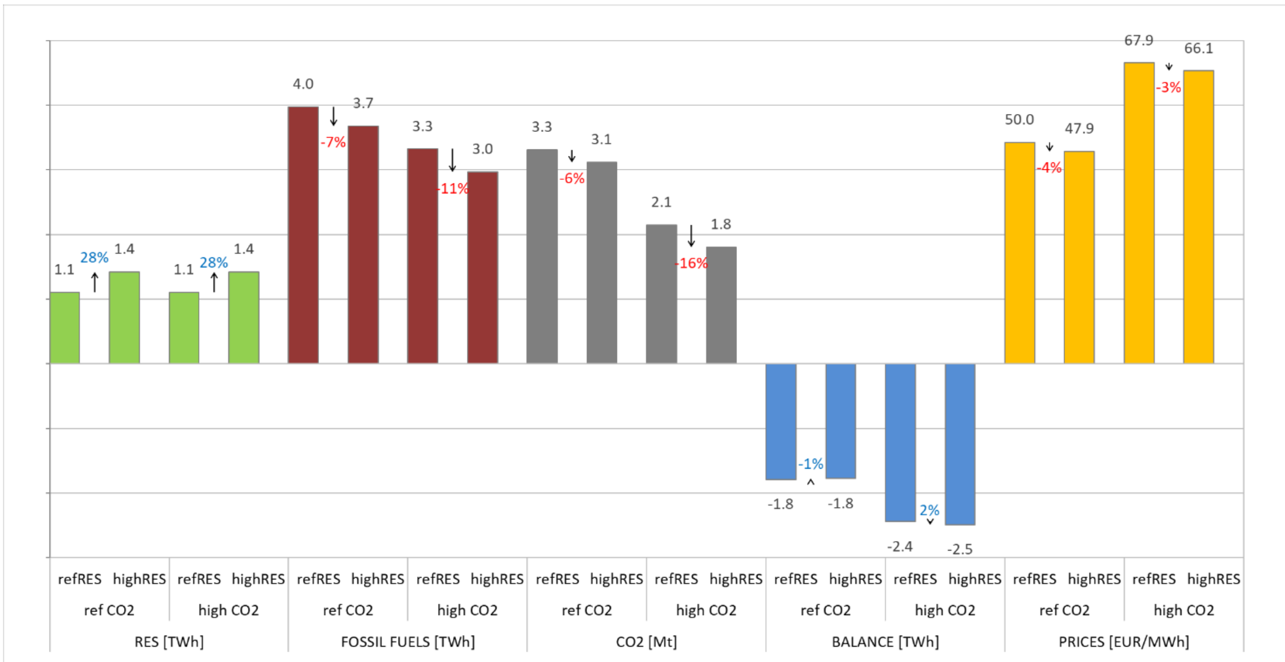


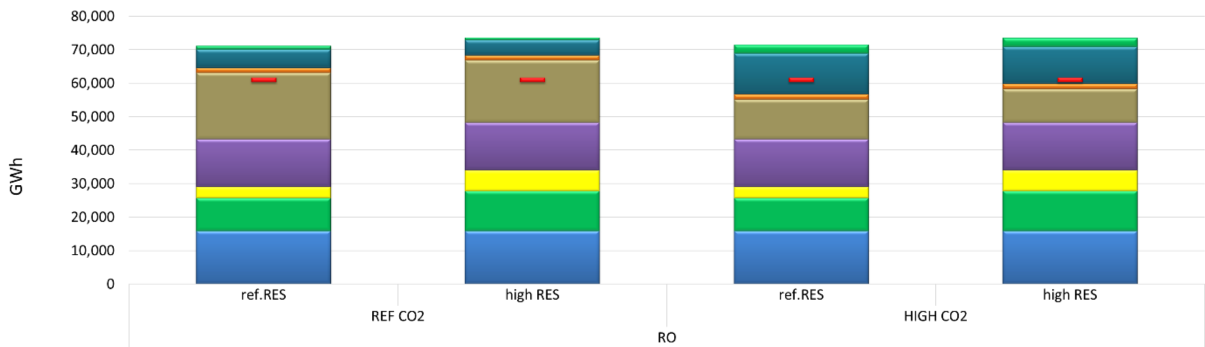
Figure 98: Main system operating indicators in MEPSO market area in 2030 - ref. RES vs high RES, ref. CO_2 and high CO_2 emission tax

Considering the generation mix presented in Figure 97, in conjunction with the main system indicators depicted in Figure 98, 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 for 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 for 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 for about 0.7 TWh.
- Regarding wholesale market price, high CO_2 emission tax implicates increase in price for 36% to a level of 66.1 – 67.9 EUR/MWh. In addition, greater RES generation leads to a decrease in prices for 3-4%.

5.3.8. Transelectrica market area

Generation mix and selected set of indicators, as the main results of market analysis for Transelectrica market area, are presented in Figure 99 and Figure 100, 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 99: Generation mix in Transelectrica market area in 2030 - ref. RES vs high RES, ref. CO_2 and high CO_2 emission tax

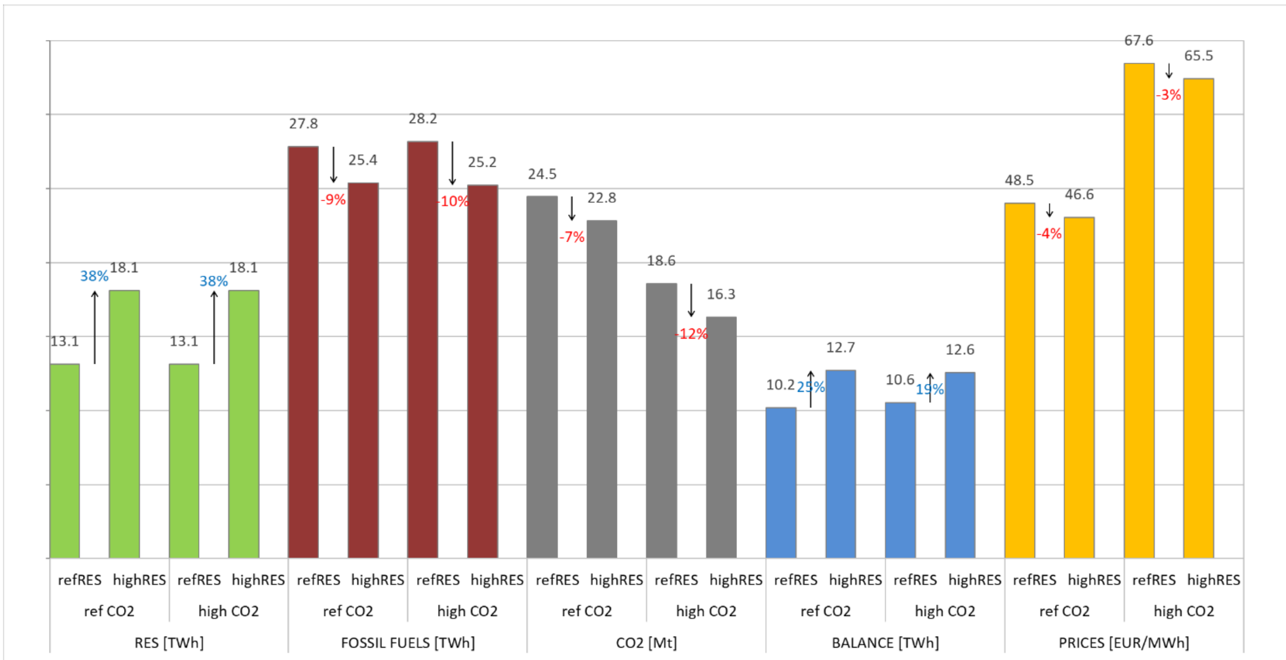


Figure 100: Main system operating indicators in Transelectrica market area in 2030 - ref. RES vs high RES, ref. CO_2 and high CO_2 emission tax

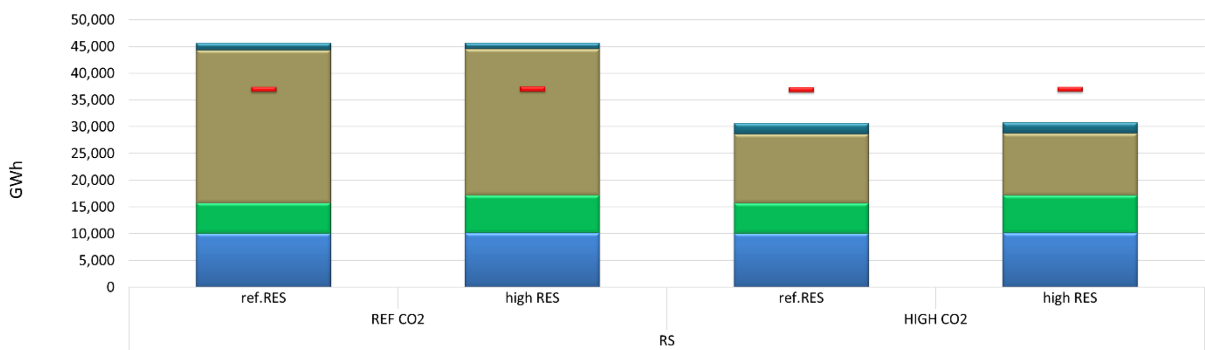
By jointly analyzing these results, the following can be concluded:

- Increase in CO_2 emission tax in 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 for 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 Transelectrica market area in the group of zones with the highest RES increase.
- RES participation in supplying the area demand in Transelectrica market area is at the regional average, between 22% and 30%.
- Increase in RES generation provokes decrease in CO_2 emissions for 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 Transelectrica market area rises for 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 for 39% (19 EUR/MWh) reaching the level of 65.5 – 67.6 EUR/MWh.
- Higher RES generation leads to a decrease in prices for 3 to 4%, depending on the level of CO_2 emission tax.

5.3.9. EMS market area

Generation mix and selected set of indicators, as the main results of market analysis for EMS market area, are presented in Figure 101 and Figure 102, 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 101: Generation mix in EMS market area in 2030 - ref. RES vs high RES, ref. CO_2 and high CO_2 emission tax

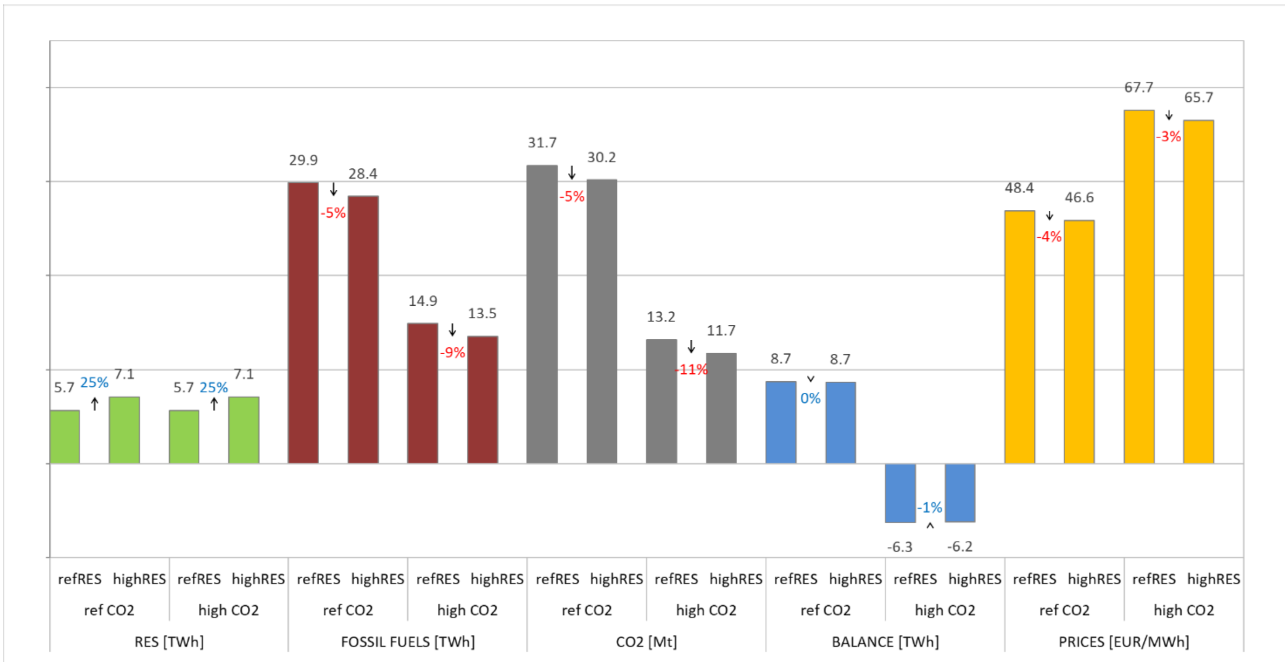


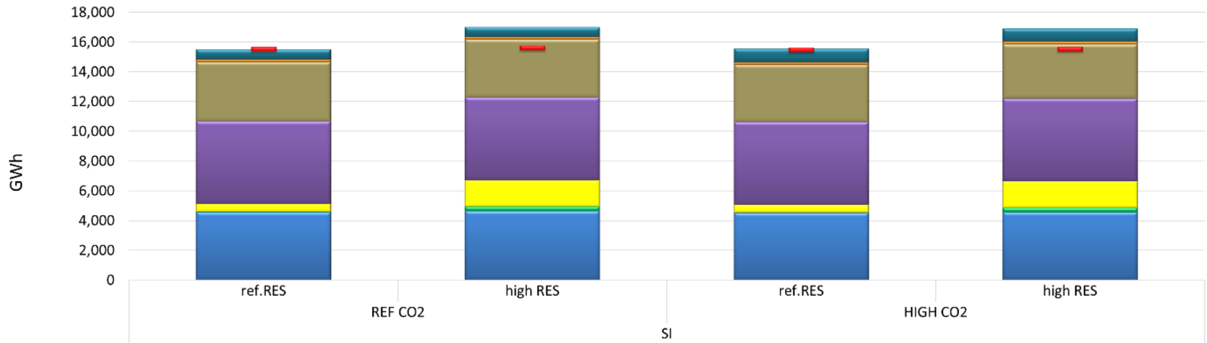
Figure 102: Main system operating indicators in EMS market area in 2030 - ref. RES vs high RES, ref. CO_2 and high CO_2 emission tax

Considering the generation mix presented in Figure 101, in conjunction with the main system indicators depicted in Figure 102, 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 for -15.7 TWh (-55%) for Ref. RES generation or -58% for High RES generation. At the same time generation from gas TPPs increased for 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 for around 19 EUR/MWh (+40%). On the other hand, increase in RES generation implicates a decrease in market price for 3-4%.
- Simulations shows that engagement of PS HPP is very small pointing to the fact that existing hydropower plants and strong regional connections enables enough flexibility for the given level of RES generation.

5.3.10. ELES market area

Generation mix and selected set of indicators, as the main results of market analysis for ELES market area, are presented in Figure 103 and Figure 104, 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 103: Generation mix in ELES market area in 2030 - ref. RES vs high RES, ref. CO_2 and high CO_2 emission tax

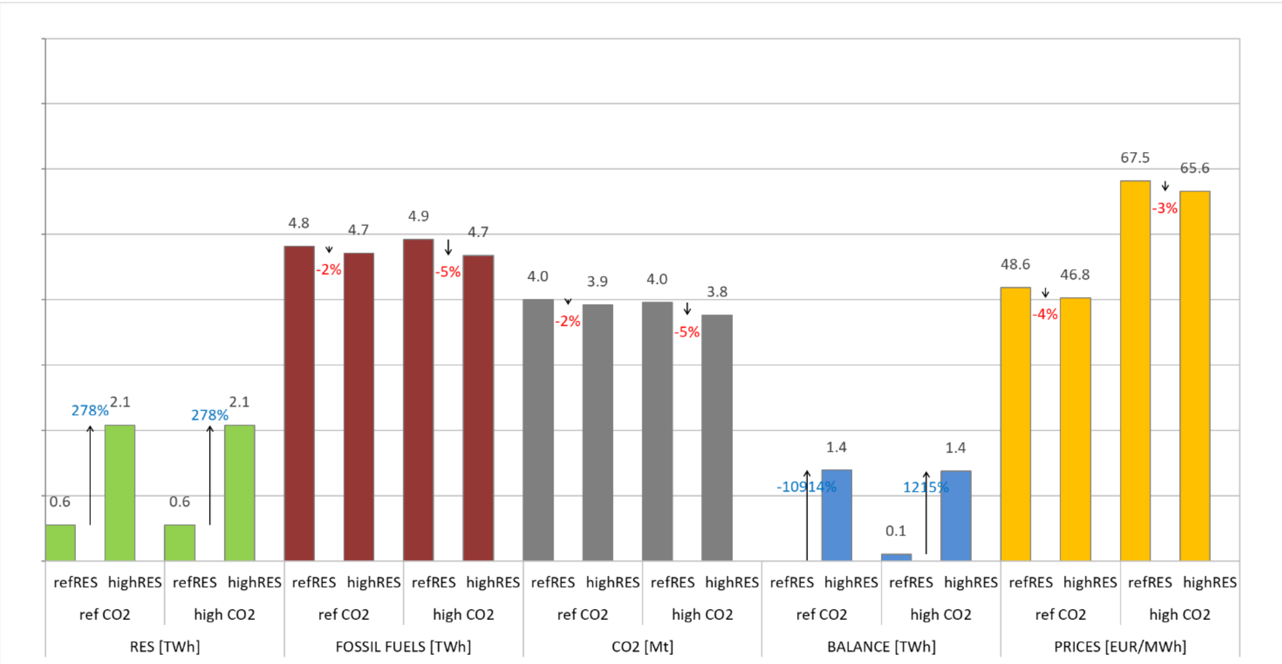


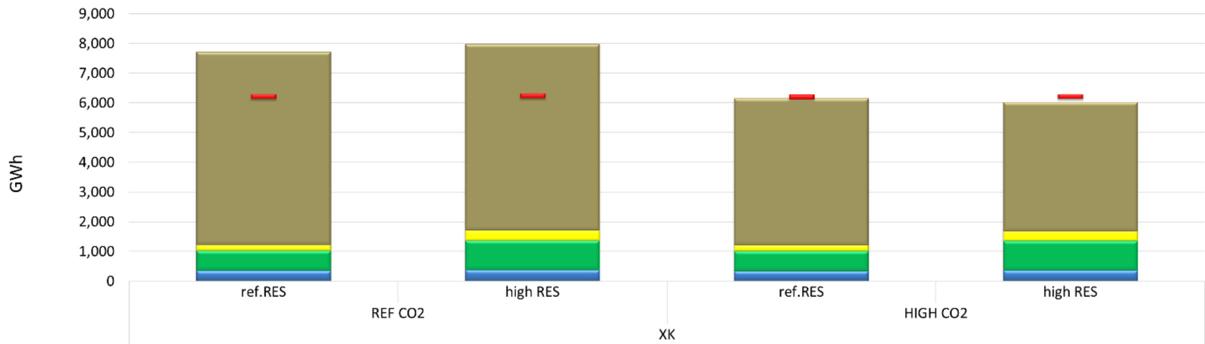
Figure 104: Main system operating indicators in in ELES market area in 2030 - ref. RES vs high RES, ref. CO_2 and high CO_2 emission tax

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 for 0.1 to 0.3 TWh (-4 – -7%), depending on the RES generation, while gas powered plants increase generation for 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 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 for 19 EUR/MWh. On the other hand, increase in RES generation implicates a decrease in market price for 3-4%.
- Simulations shows that engagement of PS HPP is very small pointing to the fact that existing hydropower plants and strong regional connections enables enough flexibility for the given level of RES generation.

5.3.11. KOSTT market area

Generation mix and selected set of indicators, as the main results of market analysis for the KOSTT market area, are presented in Figure 105 and Figure 106, 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 105: Generation mix in KOSTT market area in 2030 - ref. RES vs high RES, ref. CO_2 and high CO_2 emission tax

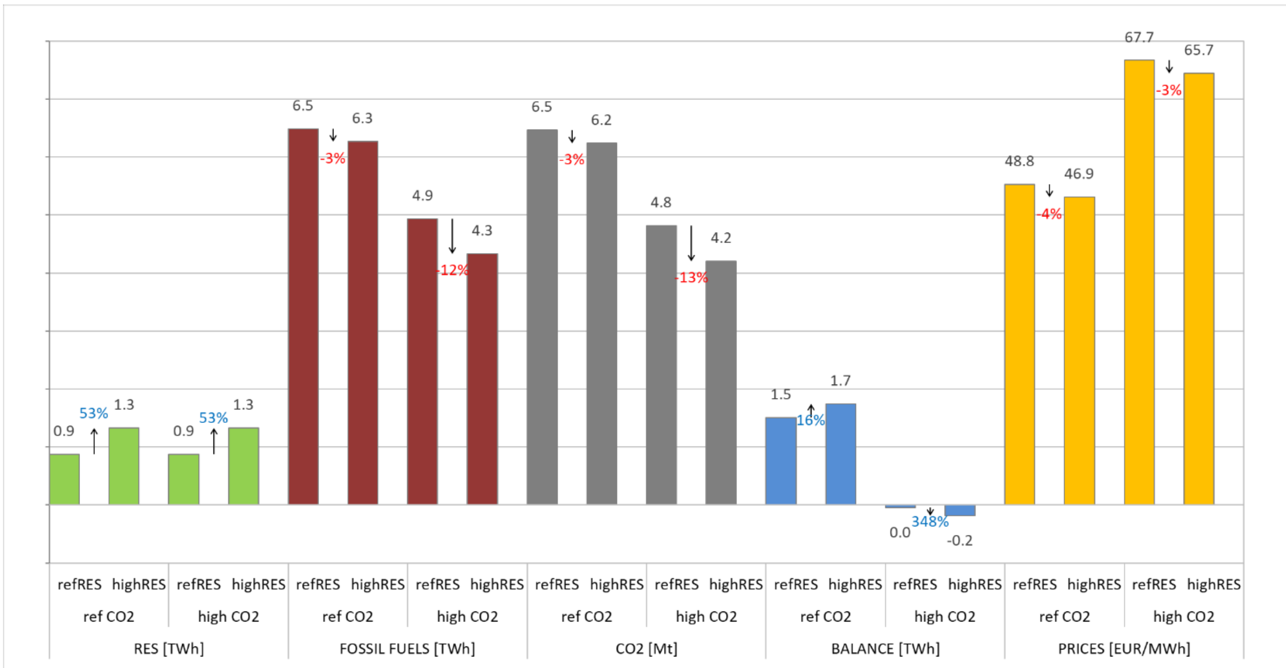


Figure 106: Main system operating indicators in KOSTT market area in 2030 - ref. RES vs high RES, ref. CO_2 and high CO_2 emission tax

Considering the generation mix presented in Figure 105, in conjunction with the main system indicators depicted in Figure 106, the following conclusions could be drawn about the operation of this market zone:

- In 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 is reduced for 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 are reduced for 1.6 Mt (-26%) and 2 Mt (-33%), depending on the level of RES generation.
- RES generation (wind+solar) rise from 0.9 TWh to 1.3 TWh (+53%) supplying between 14% and 21% of area demand.
- 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 for about 39%, in relative terms, or 18 EUR/MWh in absolute terms.
- High level of RES generation decreases price for approx. 2 EUR/MWh.
- Simulations shows that engagement of PS HPP is very small pointing to the fact that existing hydropower plants and strong regional connections enables 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

Systematized results for 3 groups of scenarios present the basis for overall assessment of different levels of RES on market operation in SEE. In general the following conclusions can be derived:

- **In 2030 in EMI region, RES generation increases from 57.7 TWh (in ref. RES scenario) to 75.3 TWh in high RES scenario which is the increase of 30%. Increase per market areas (Figure 107) is between 0.2 and 6 TWh (in CGES and IPTO market areas) or between 19% and 278% (in HOPS and ELES market areas respectively).**

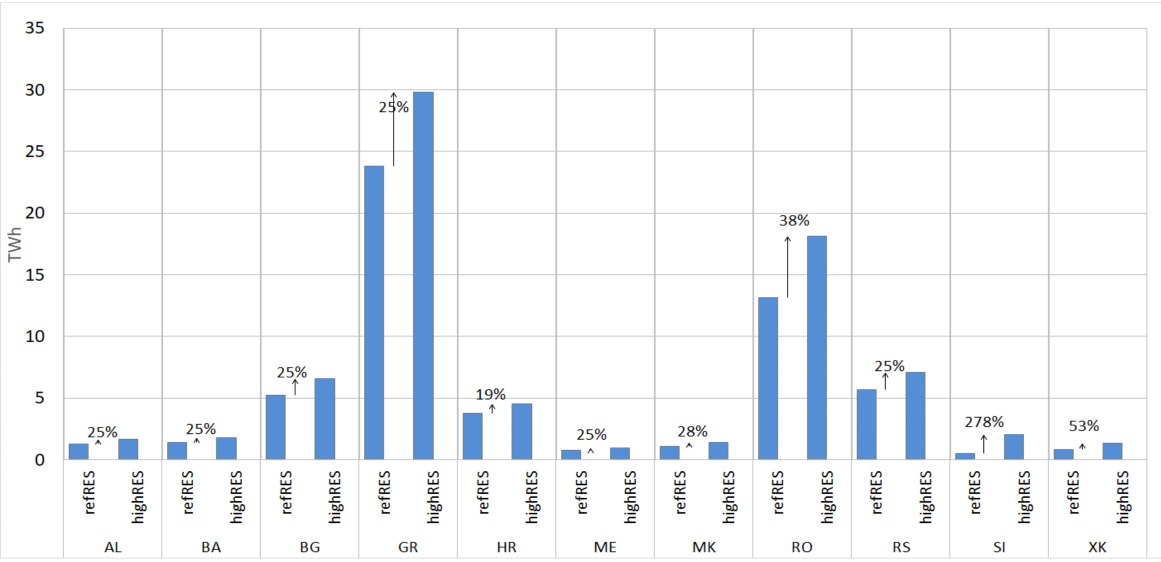


Figure 107: RES generation in 2030 - ref. RES vs high RES

- **This change in RES generation provokes decrease of TPPs generation, lignite and gas fired plants generation at the level of 10%. In all scenarios, this decrease is smaller than increase in RES generation and, with higher RES generation, region increases its export.**
- In 2030, one relevant driver in determination of the main generation technology is the expected level of CO_2 emission tax. Increase in CO_2 emission tax will change the generation costs for fossil fuels fired plants with bigger impact on lignite and coal fired plants. With higher CO_2 tax, generation from lignite fired plants (in some cases) become more expensive than generation from gas fired plants, lignite fired plants become less competitive and these two technologies change their position in the regional merit order curve. This is why participation of these technologies in supplying the load and their share in generation mix is significantly different in scenarios with referent and high CO_2 tax (Figure 108).

  In case of referent level of CO_2 tax (27EUR/tCO2), lignite is the main technology, while in case of higher CO_2 emisison tax (almost doubled, 53 EUR/t CO_2), shares of lignite and gas fired plants become almost the same. When generation from lignite fired plants are decreased, then hydro generation becomes dominant, at

least in average hydrological conditions. In dry hydrological conditions, lignite remain main technology even in case of high CO_2 tax.

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

Capacity factors of lignite and gas fired plants generation changes more with changes in CO_2 tax. At lignite fired plants capacity factor decrease from the level of 60-70% in case of referent CO_2 tax to 35-50% in case of high tax. At gas fired plants change has opposite direction and capacity factor increase from 16-30% in referent CO_2 tax case to 36-50% in high tax case.

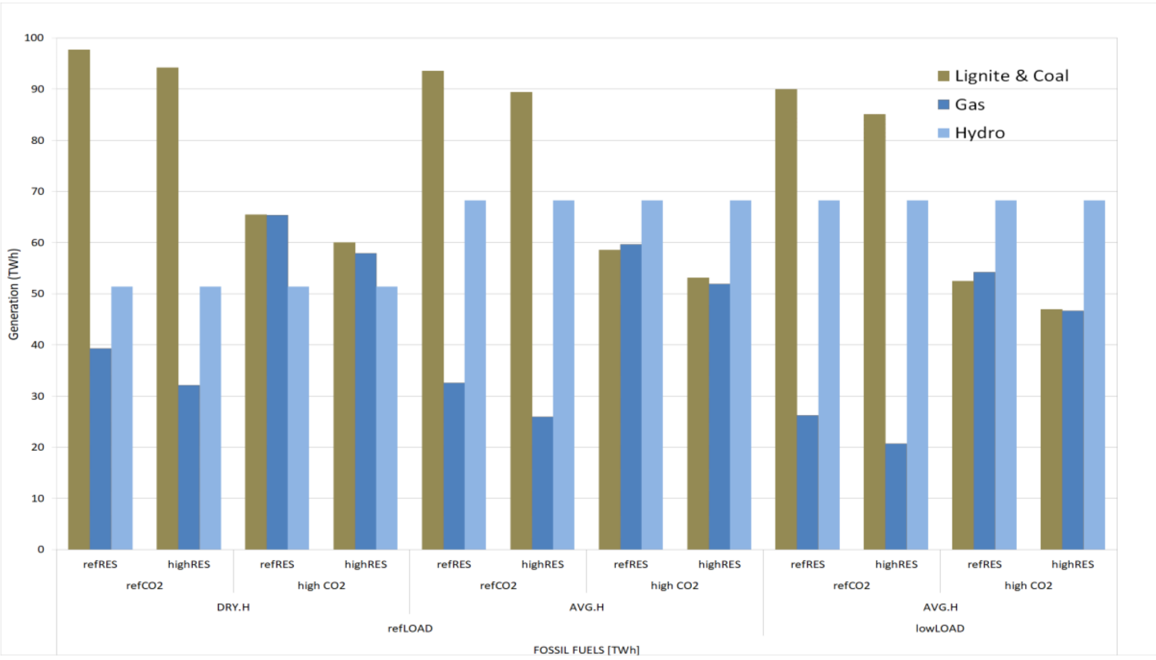


Figure 108: Fossil fuels and hydro generation in all scenarios in 2030

- 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 EMI region in 2030, but **considered together as "green" technologies, hydro and RES generation become the main sources and supplies between 39% and 51% of total demand, or in case of slower demand growth even 54% of total demand.**
- As presented in the Figure 109, the highest fossil fuels fired plants generation is expected in the case of referent demand, referent CO_2 emission tax and dry hydrology, and it is decreased in cases of higher CO_2 tax, more hydro generation (in average hydrology) and reduced regional demand.

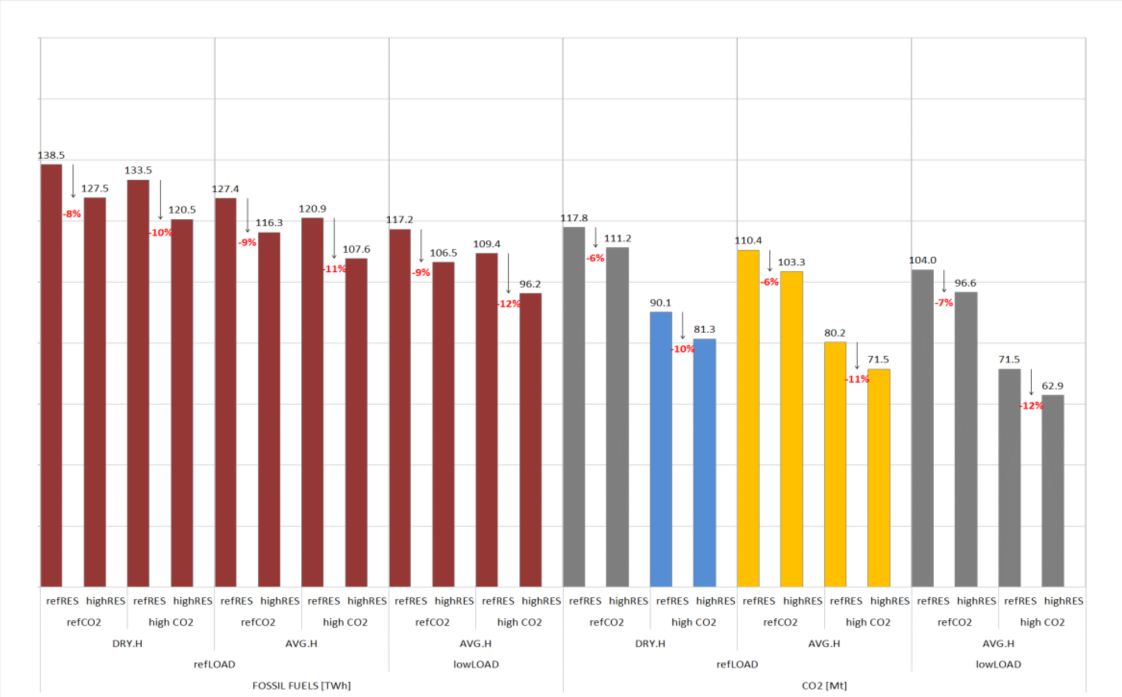


Figure 109: Fossil fuel powered plants generation in 2030 – all scenarios

- 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). Due to this increase in RES generation, fossil fuel powered plants generation is decreased and consequently also CO_2 emisison (Figure 109). **Higher RES generation provokes decrease of both: lignite and gas fired plants generation in almost same volume (Figure 108). The reason for this lies in the fact that in one of the biggest market areas in the region (IPTO) in 2030 only gas fired units exist while in all other market areas, decrease of fossil fuel fired plants generation, due to increased generation from RES, is almost equally divided between lignite and gas technologies.**

- EMI region has different net positions in different scenarios, as presented in Figure 110. **In case of high CO_2 emission, dry hydrology and referent level of RES generation, 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 EMI region can reach 18.4 TWh or 6.9% of total demand.**

  Higher CO_2 tax reduces 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 smaller impact in comparison to the impact of CO_2 tax.

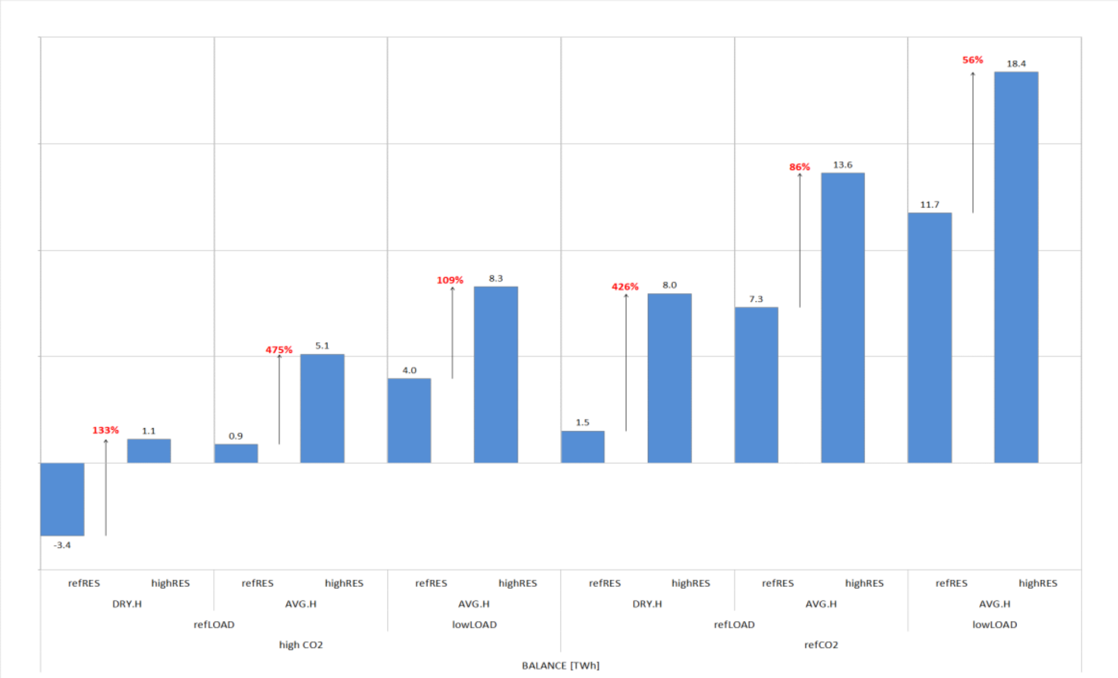


Figure 110: Balance positions of the EMI region in 2030 – all scenarios

Changes in balance positions for all market zones shows that in almost all zones where lignite powered plants have significant share in generation mix, export is reduced or zone even becomes net importer (NOSBiH, EMS, KOSTT markets areas) due to increase in CO_2 emission tax (Figure 111). Market areas where gas powered plants have high impact on generation mix, export increases (Transelectrica market area) or import decreases (HOPS market area). IPTO market area, due to significant generation capacities in gas technology, becomes net exporter in case of high CO_2 tax.

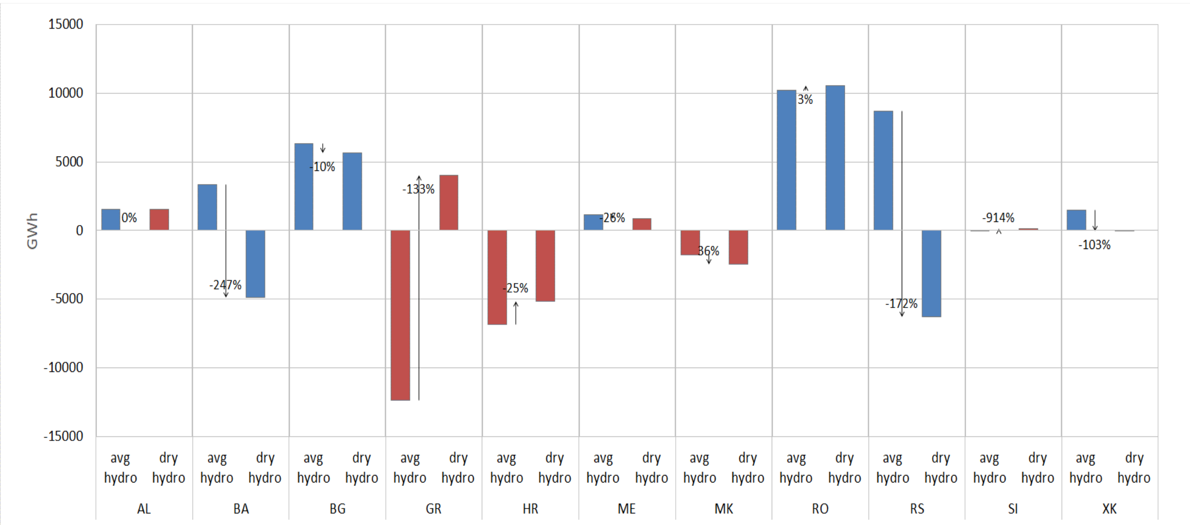


Figure 111: Balance positions per market areas in 2030 - ref. CO2 vs high CO2, referent RES integration

- **Average regional prices (Figure 112) are between 47.4 and 70.5 EUR/MWh** with decrease provoked by high RES integration of around 2 EUR/MWh or 4% in all scenarios. From the same figure it could be seen that main driver for **higher prices is the value of CO_2 tax: increase of CO_2 tax from 27 EUR/tCO2 to 53EUR/tCO_2 would lead to wholesale market prices increase in EMI region in 2030 for around 18 EUR/MWh or to increase for around 35%.**

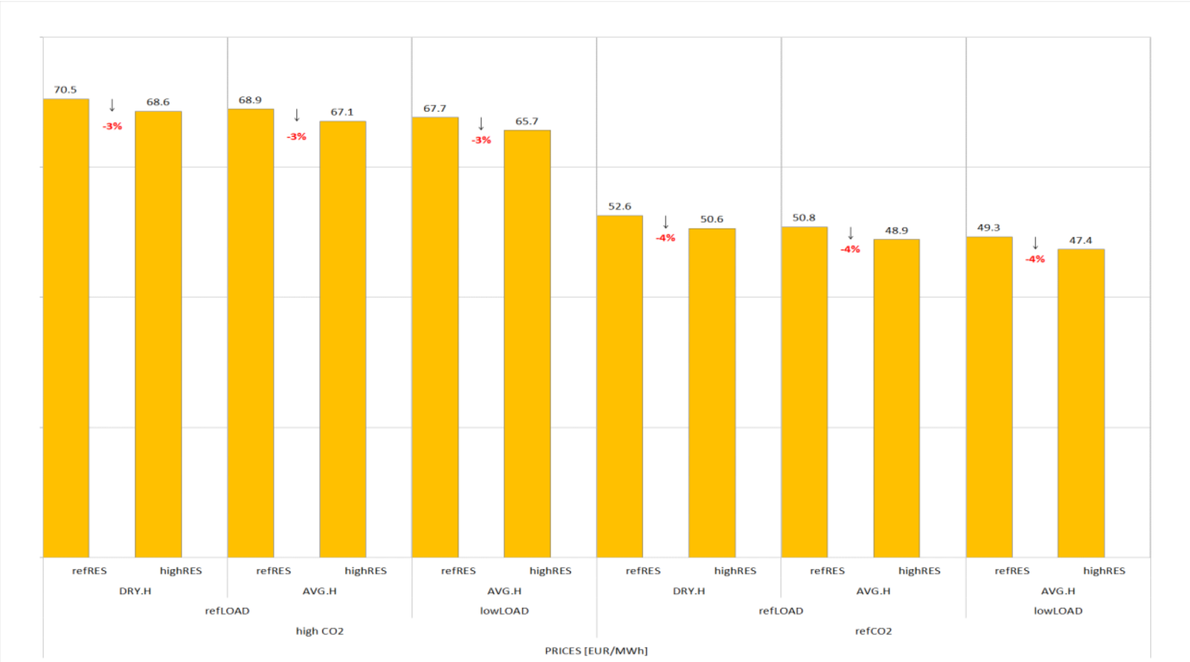


Figure 112: Prices in EMI region in 2030 - ref. RES, average hydrology

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.

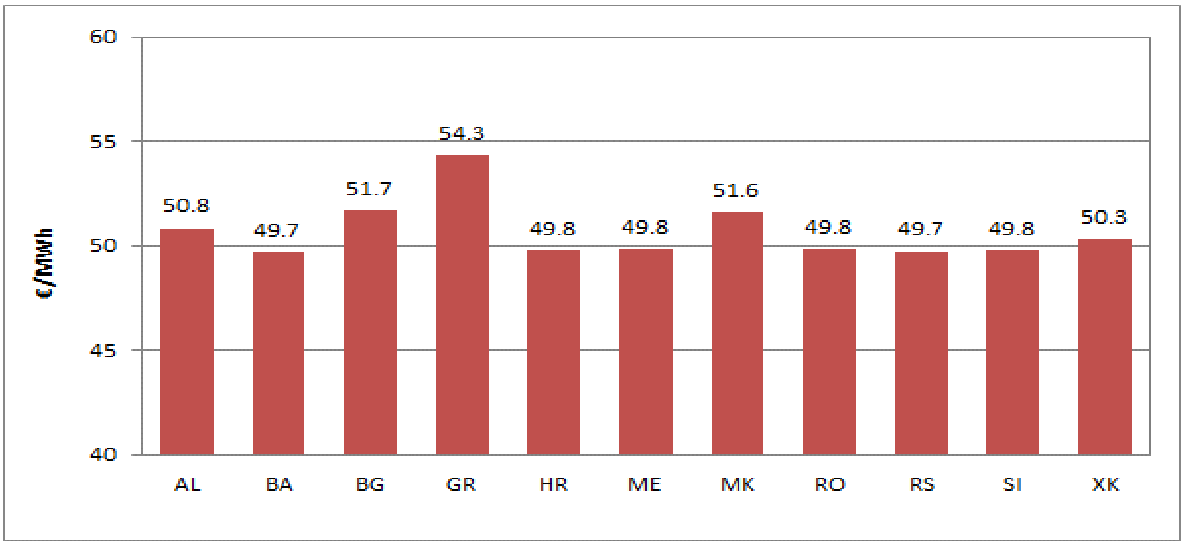


Figure 113: Prices in EMI region in 2030 – ref CO2 & ref. RES, average hydrology

In case of referent CO_2 tax there are 4 price zones in EMI region disregarding hydrology, demand growth or level of RES (Figure 113):

1) IPTO, 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 but between central zones and IPTO
4) All other zones

In case of high CO_2 tax, balance positions of the zones are changed and practically all zones are couple in one price zone without congestion between them (Figure 114).

Figure 114: Prices in EMI region in 2030 - ref. RES, average hydrology – Alternative CO_2 emission tax

It should be also noted that conventional units (mainly hydro and PSPs) as well as good interconnections between EMI market zones in SEE provides enough flexibility to cope with hourly variablility in RES generation. The confirmation of this can be found in the fact that there are no spillages or curtailments in wind, solar or hydro generation in analysed scenarios.

5.5. Additional market assessment of natural gas system development

In addition to the market simulations carried out with the focus on high RES scenarios, we made simulations with the focus on additional gas fired plants.

According to conclusions given by work of USAID/USEA Natural Gas Working Group - Eastern Europe Natural Gas Partnership additional 1155 MW of gas fired power plants is added to the current fleet of natural gas generation units. This additional capacity in

gas TPPs provokes an increase of 3.2% in total installed TPPs capacity in EMI region in 2030. On the other hand, if only gas powered TPPs are analyzed, than additional 1155 MW of gas technology implicates an increase of 7.4% of total gas based TTPs in the EMI region in 2030.

Additional gas-fired generation capacities consist of 5 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:**
    - **TPP TE-TO 2 – 220 MW**
    - **TPP Negotino – 250 MW**

The results of corresponding market analyses are given in sequel.

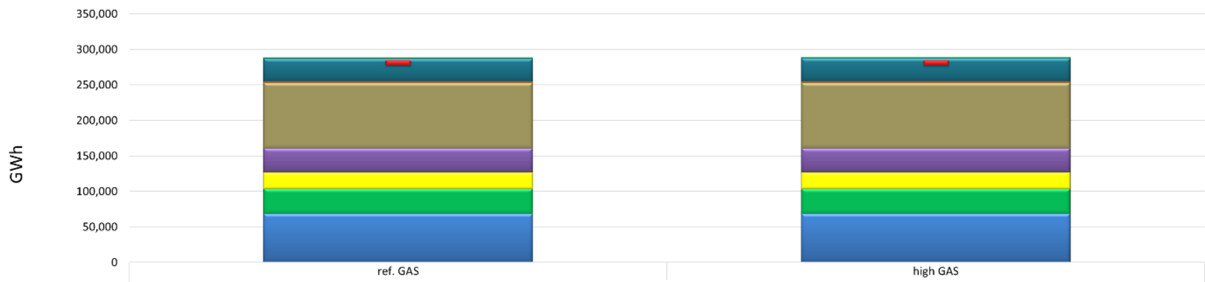
Impact of additional gas generation capacities is analyzed here in comparison to the referent scenario without additional gas TPPs.

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

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

Ref GAS scenario is in fact the same scenario as the first scenario in the first group of scenarios presented in chapter 5.1.

Generation mix for the whole EMI region is given on the Figure 115, while the main indicators are presented in Figure 116.



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

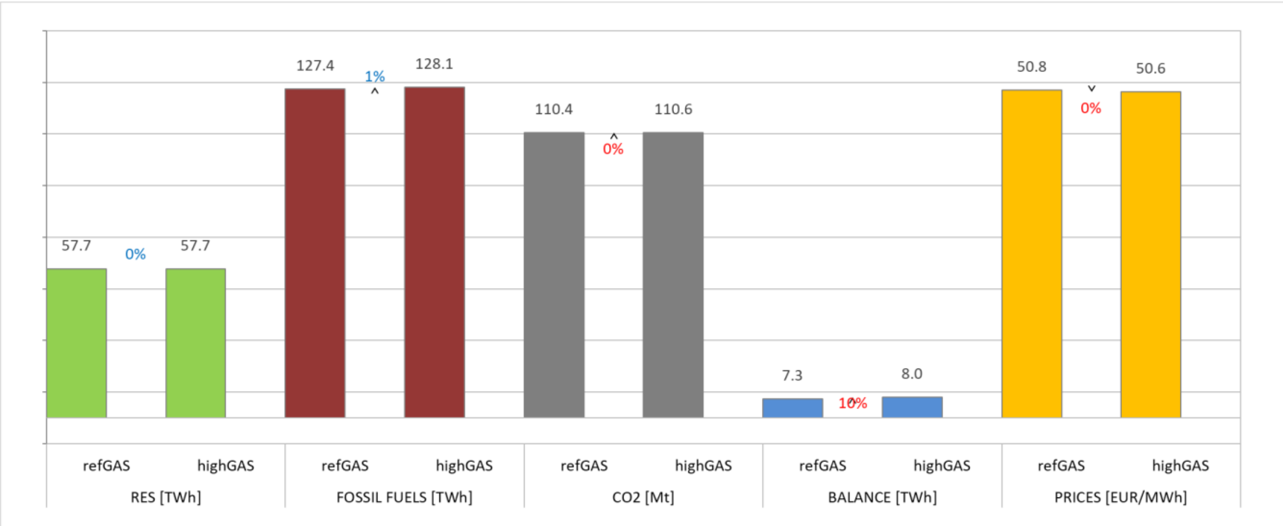


Figure 116: Main system operating indicators in EMI region in 2030 - ref. GAS vs high GAS

The following conclusions can be drawn out of this market analysis:

- **Generation mix in high GAS scenario is not significantly changed compared to ref GAS (baseline) scenario.**
- The main technology in 2030 is still lignite and it supplies more than 33% of the load, followed by HPPs which supply 24% of the load, while RES participates with 21%, for both levels of gas TPPs installed capacities. Gas-fired TPP generation is stable and it is not significantly changed with additional gas-fired TPPs in the region. **In high GAS scenario the generation from gas-fired TPPs on the regional level slightly increases for 0.7 TWh or just 2.5% of total generation from gas-fired TPPs or 0.3% of total regional load. In equivalent, with new 1155 MW in new gas-fired TPPs, total generation increases for 0.7 TWh, atough their total electricity output is 2.2 TWh.**

- These results show that despite of additional gas-fired TPP capacities (1155 MW), total gas-fired generation in the region will not change significantly. However, the reason behind is in the fact that at the same time generation from existing, old gas-fired TPPs in the region will decrease due to its higher marginal generation costs. **In other words, new gas-fired TPPs generation will mainly replace existing gas-fired TPPs generation in the region. It happens mainly in IPTO market area (-1.2 TWh or -6% of existing gas TPPs generation), Transelectrica market area (-0.3 TWh or -4% of existing gas TPPs generation) and ESO EAD market area (-0.2 TWh or -27% of existing gas TPPs generation)**, as given on the following Figure 117.

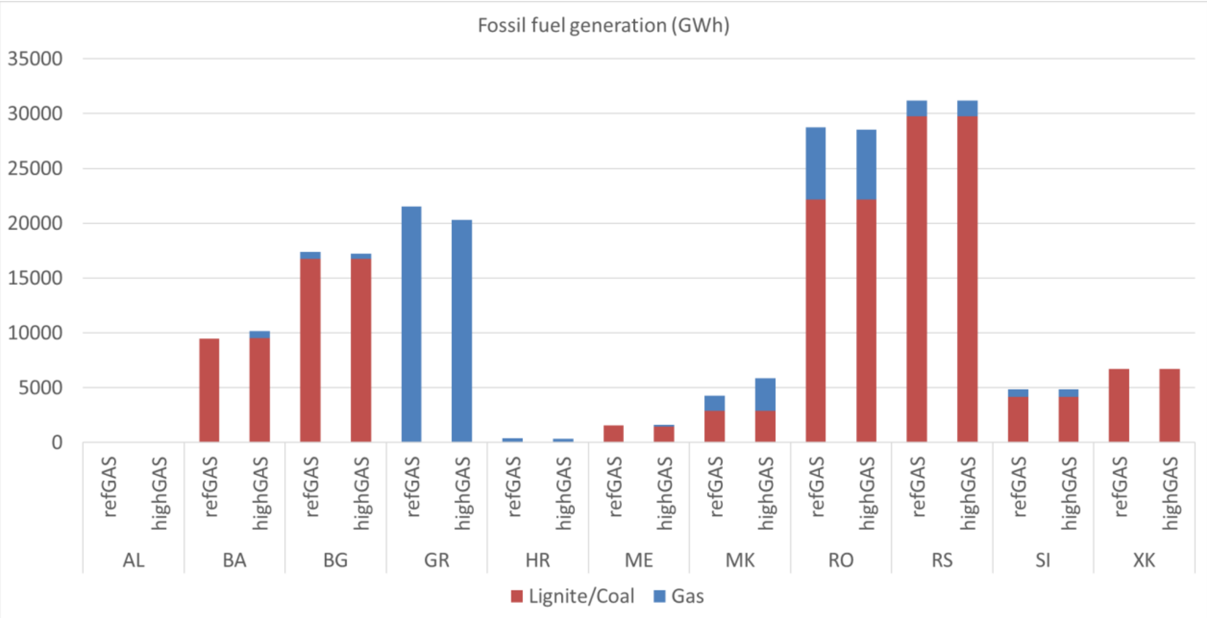


Figure 117: Fossil fuel powered plants generation in 2030 - ref. GAS vs high GAS

- **However, new gas-fired TPPs will increase total gas-fired TPPs generation in their markets areas for 2.9 TWh in total** (NOSBIH market area, MEPSO market area and CGES market area), except in OST market area. In the NOSBIH, MEPSO and CGES market areas generation from gas TPPs increases for 0.6 TWh, 1.6 TWh and 0.7 TWh, respectively. It is interesting that in OST market area, despite of new gas TPP generation capacity, hydro still has dominant role and gas-fired TPPs are not competitive and not active on the market in this scenario.

- **With new gas-fired TPPs in the region the engagement of existing pump storages is decreased.** It effects total regional consumption and consequently total electricity balance (export) of the region.

- EMI region is a net exporter in 2030. Additional gas-fired TPPs will slightly increase EMI export. Compared to referent case it grows from 7.3 TWh to 8 TWh or from 2.6% to 2.8% of total demand. In **High GAS scenario, EMI region increases its net export for approx. 10% (Figure 116).**

- **In any case, hydro and RES technologies, which can be considered as "green" technologies, will become the main power generation technologies in EMI region**

in 2030, no matter of additional gas-fired TPP capacities. These green technologies are expected to supply 45% of total demand.

- Changes in balance positions for all market zones are in correlation with increase or decrease in generation from gas TPPs, as given on the Figure 118.

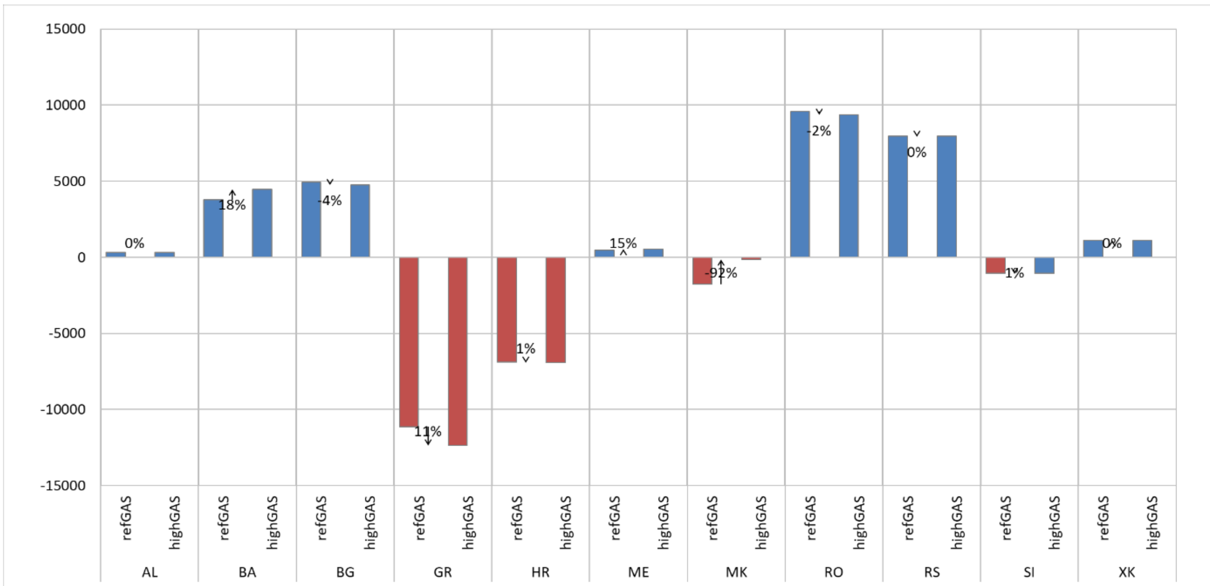


Figure 118: Balance positions per market areas in 2030 - ref. GAS vs high GAS

- Average regional prices (Figure 119) are slightly decreased for 0.2 EUR/MWh, as shown on the following figure. The greatest change in the wholesale market price can be noticed in MEPSO market area where the price declines for 0.5 EUR/MWh.

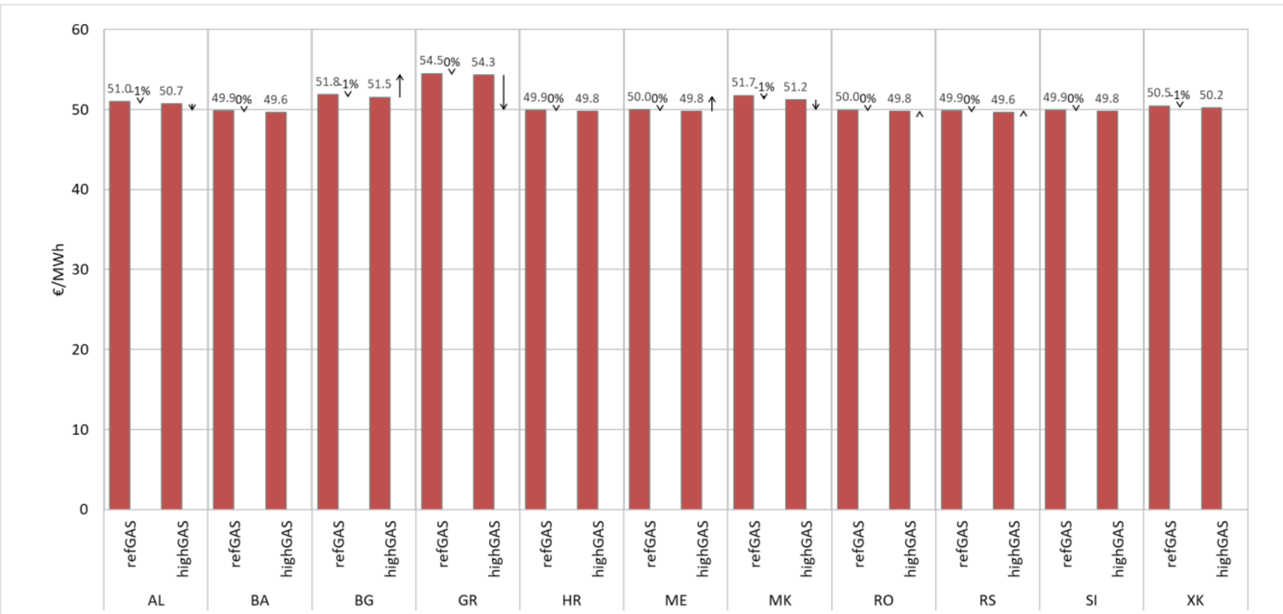


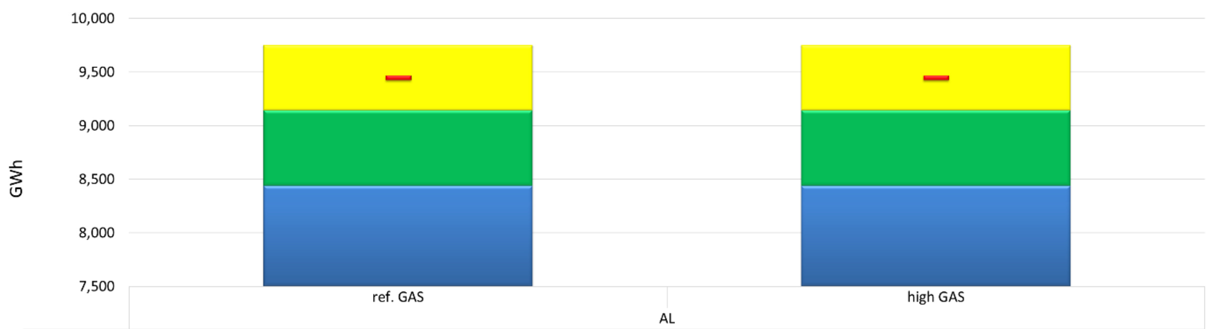
Figure 119: Prices in EMI region in 2030 - ref. GAS vs high GAS

- **From all above-mentioned it can be concluded that additional gas-fired generation capacities do not change regional generation mix significantly.** Total generation from gas-fired TPPs is slightly increased (0.7 TWh) compared to the referent case without new gas fired TPPs. **It leads to the conclusion that additional gas generation capacities compensate generation from older and less competitive TPPs and at the same time provide flexibility to the power system in order to utilize RES and hydro resources in technical and economical more efficient way. Further proof for that is that with new gas capacities EMI net export is increased for 10%.** However, in the case of different CO_2 emission taxes and different levels of wholesale electricity prices on the neighboring electricity markets, different generation mix could be expected. **But, in any case, the most important role of new gas-fired TPPs in the region will be in their flexibility needed to accommodate expected high-scale RES integration in the near future.**

All above mentioned conslusions were given from the regional perspective. Individual EMI market area perspectives and values are given in the following subchapters.

However, similar conclusions can be drawn both from regional and individual perspective. Therefore, no additional repetitive conclusions are written in the following subchapters, but only relevant graphs are given.

5.5.1. OST market area



	ref. GAS	high GAS
	AL	
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 120: Generation mix in OST market area in 2030 - ref. GAS vs high GAS

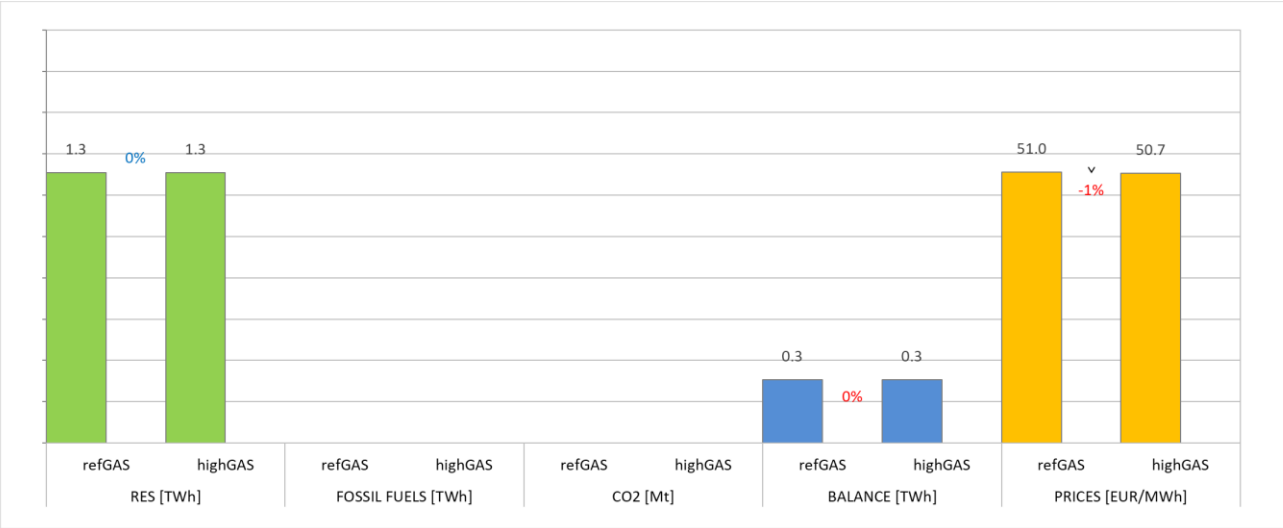
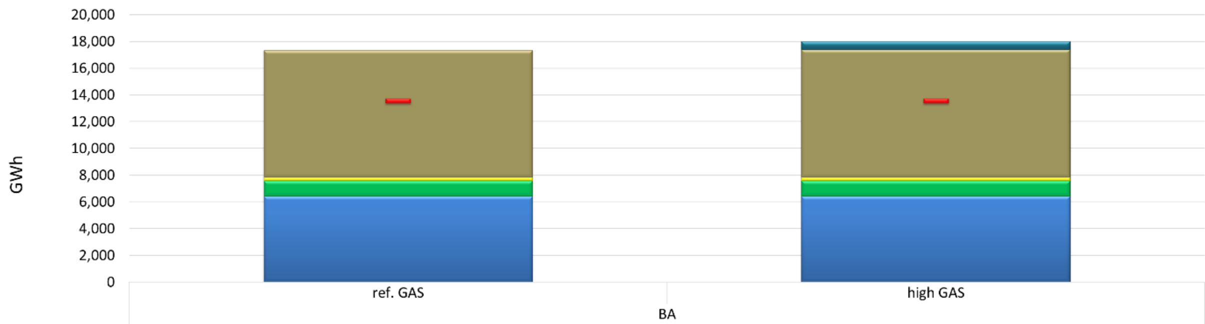


Figure 121: Main system operating indicators in OST market area in 2030 - ref. GAS vs high GAS

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

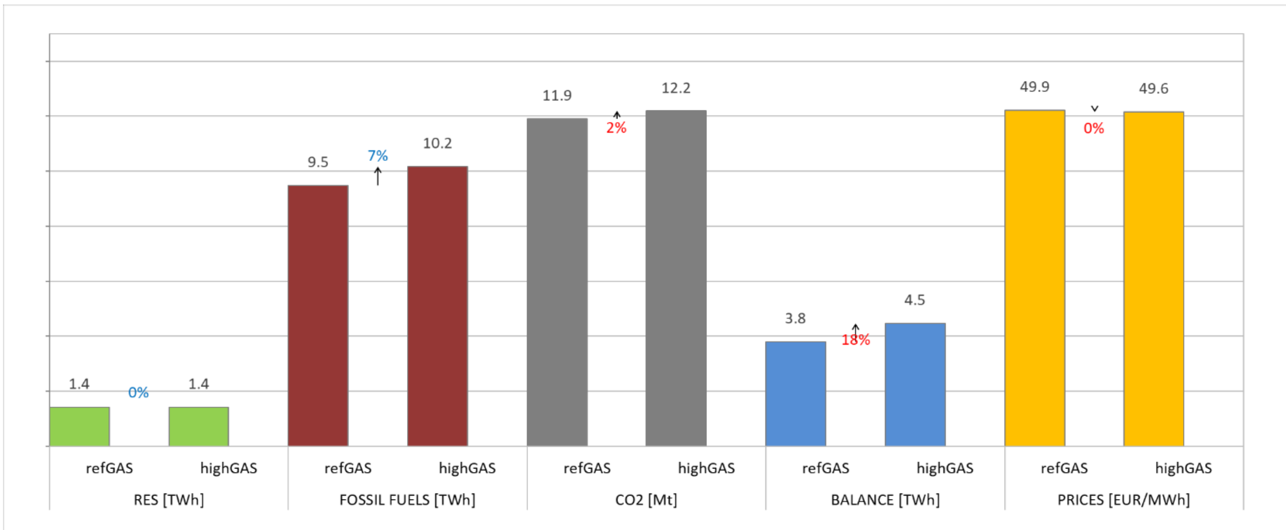
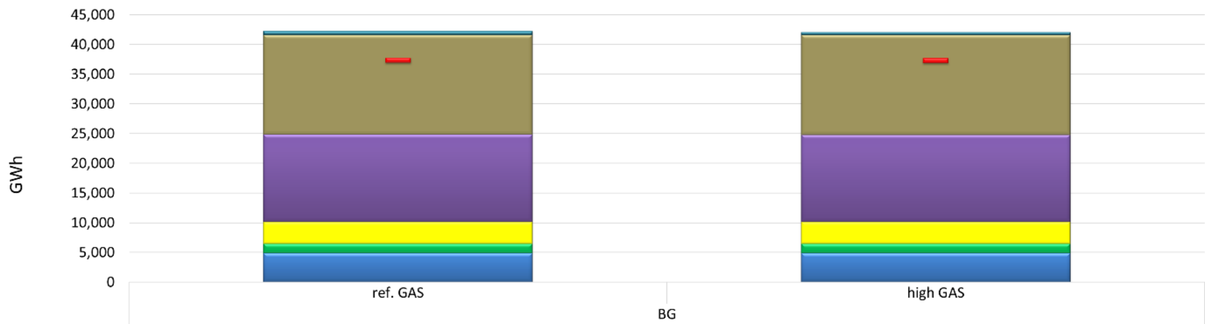


Figure 123: Main system operating indicators in NOSBIH market area in 2030 - ref. GAS vs high GAS

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

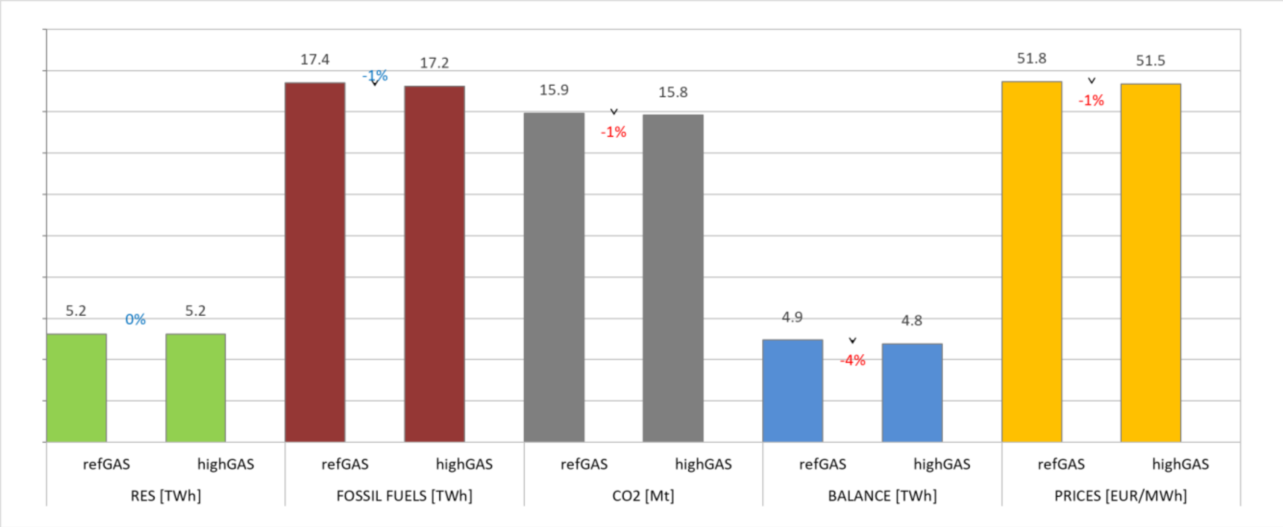
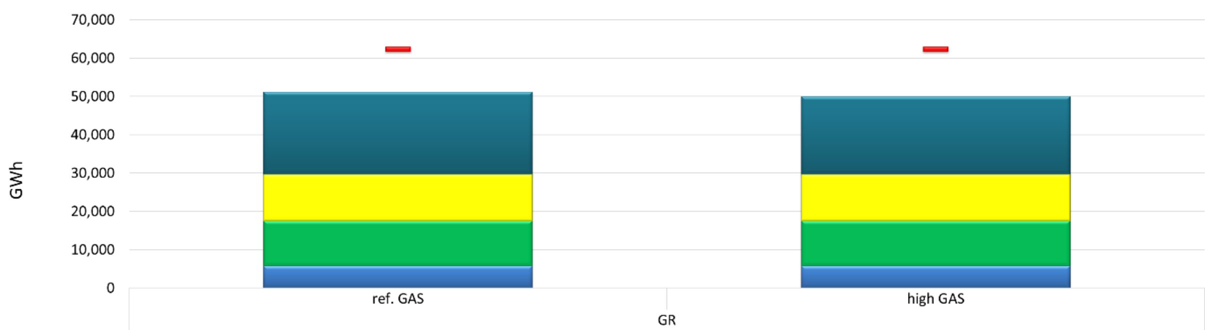


Figure 125: Main system operating indicators in ESO EAD market area in 2030 - ref. GAS vs high GAS

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

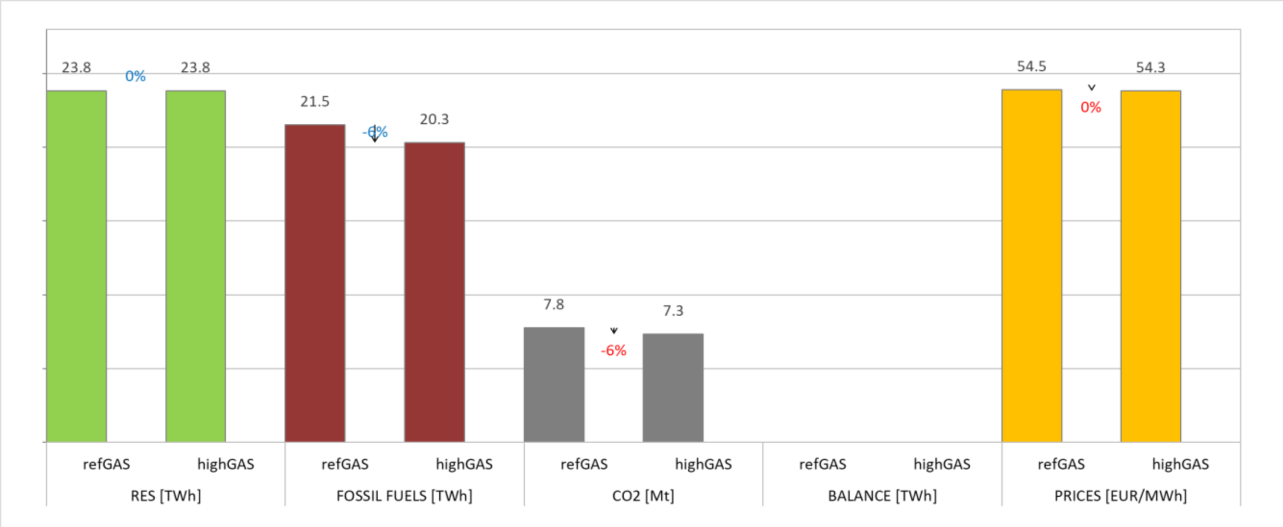
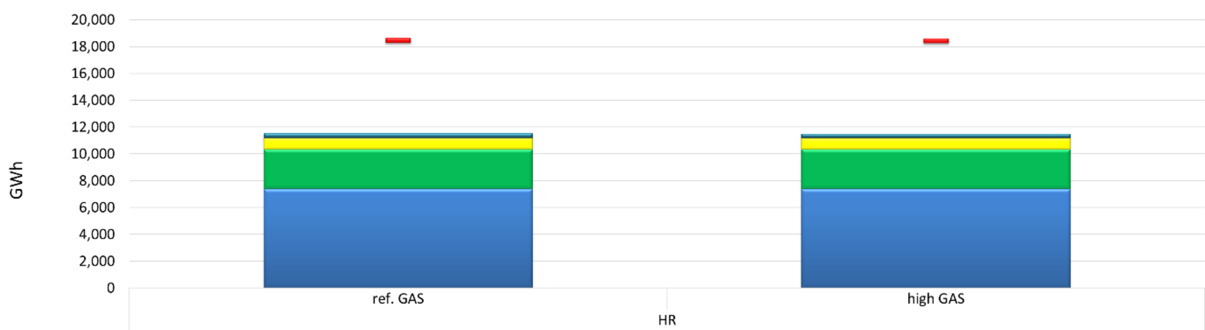


Figure 127: Main system operating indicators in IPTO market area in 2030 - ref. GAS vs high GAS

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

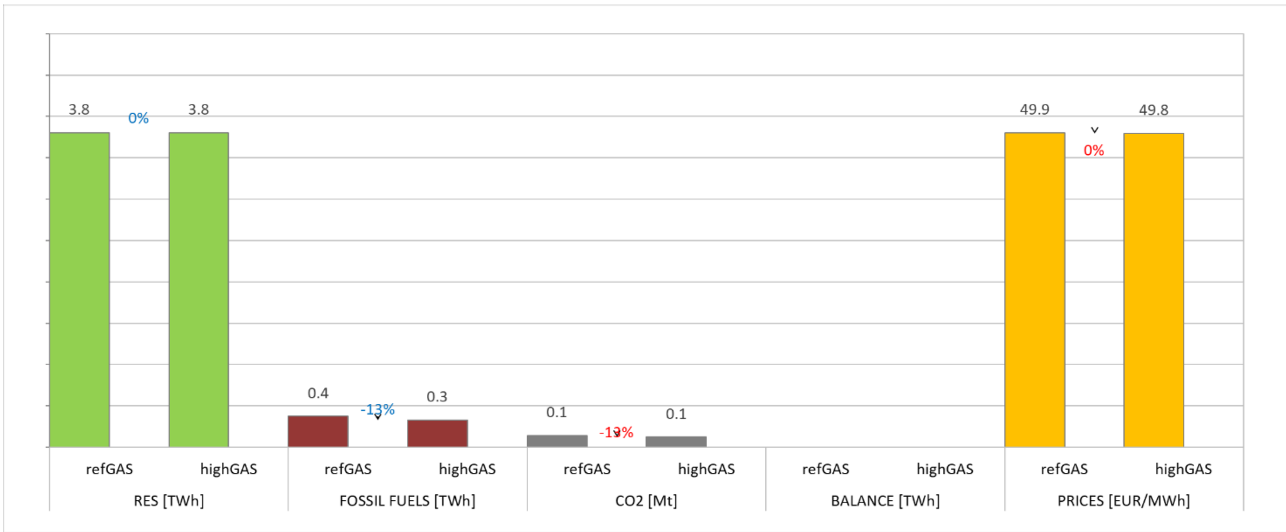
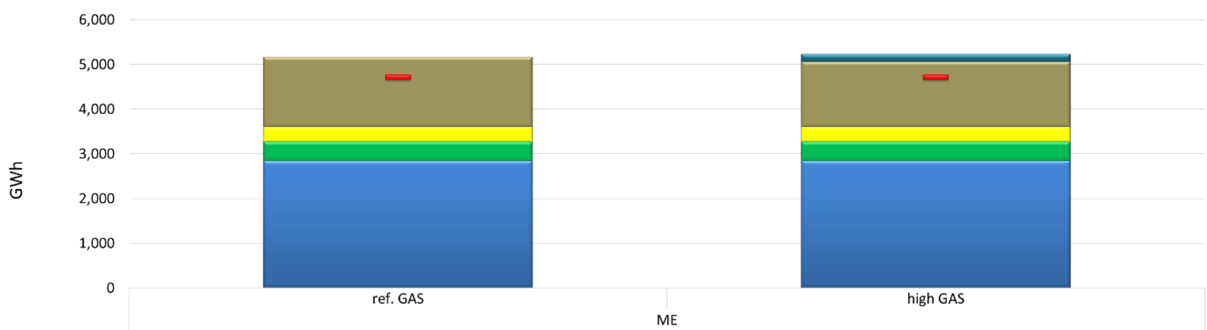


Figure 129: Main system operating indicators in HOPS market area in 2030 - ref. GAS vs high GAS

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

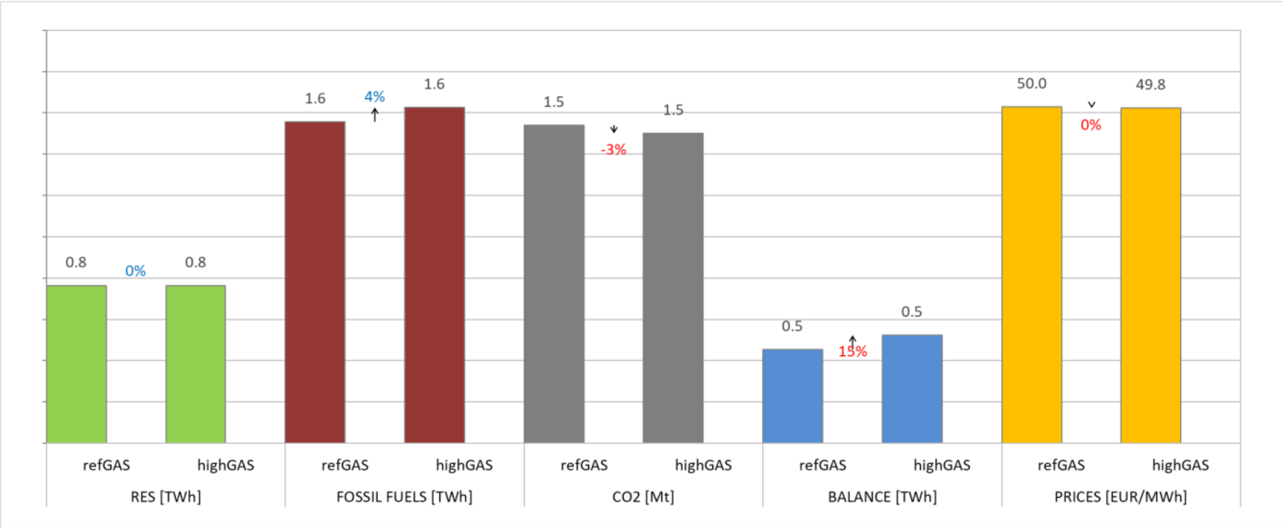
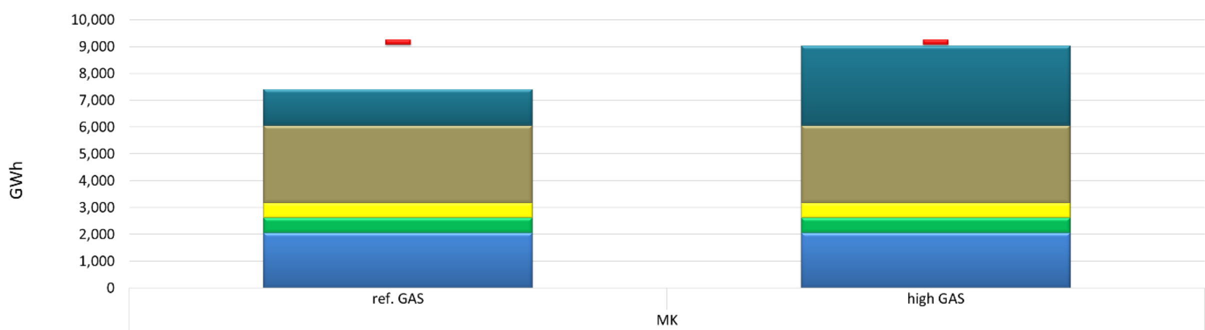


Figure 131: Main system operating indicators in CGES market area in 2030 - ref. GAS vs high GAS

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

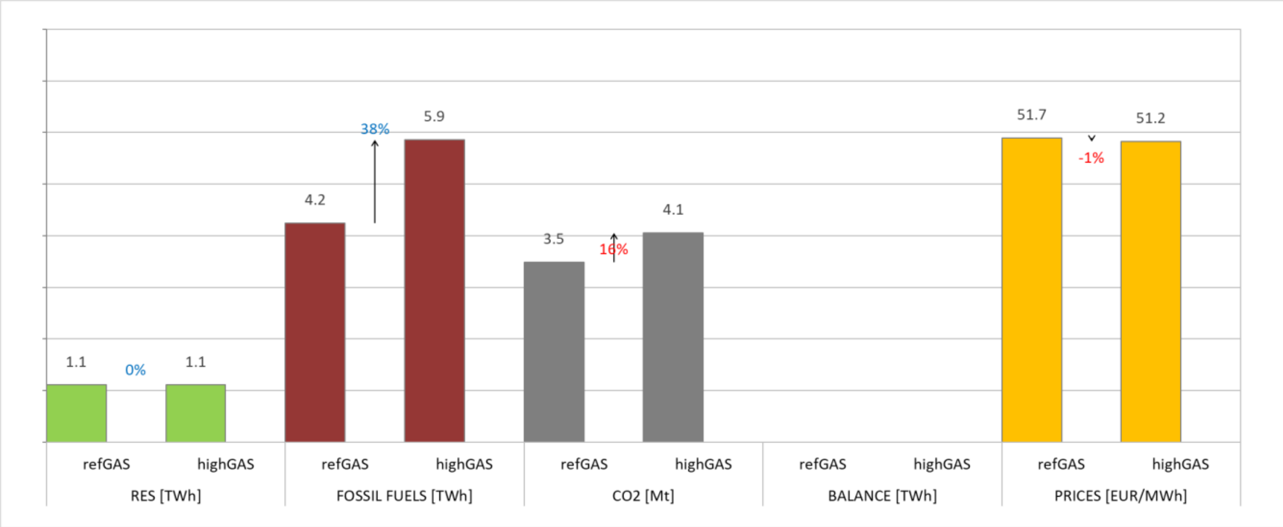
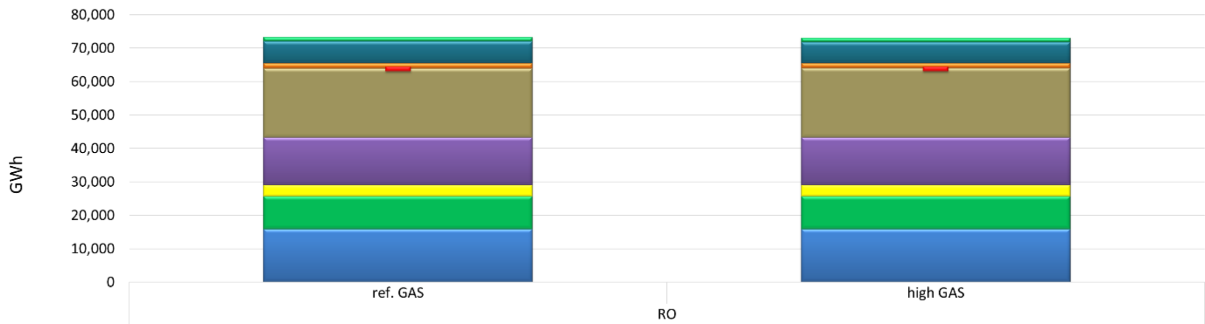


Figure 133: Main system operating indicators in MEPSO market area in 2030 - ref. GAS vs high GAS

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

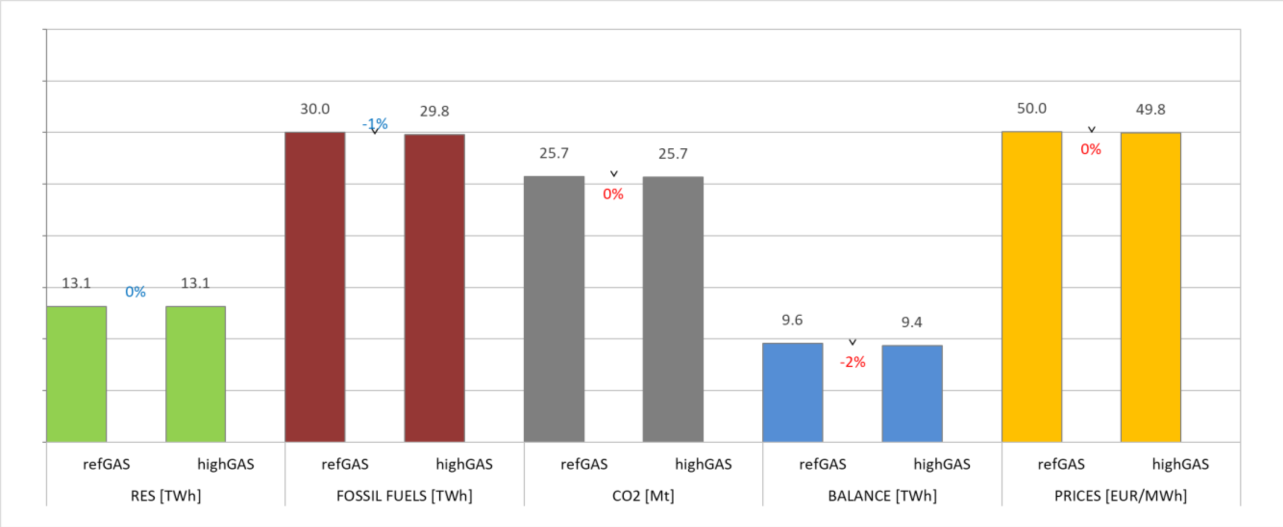
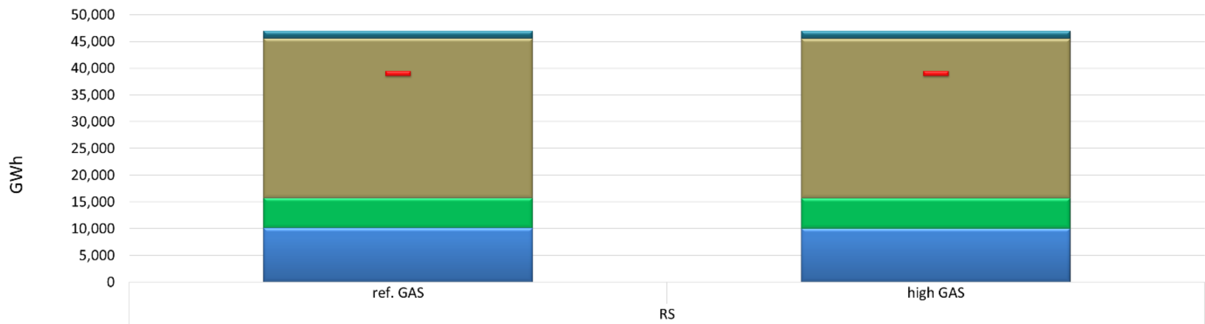


Figure 135: Main system operating indicators in Transelectrica market area in 2030 - ref. GAS vs high GAS

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

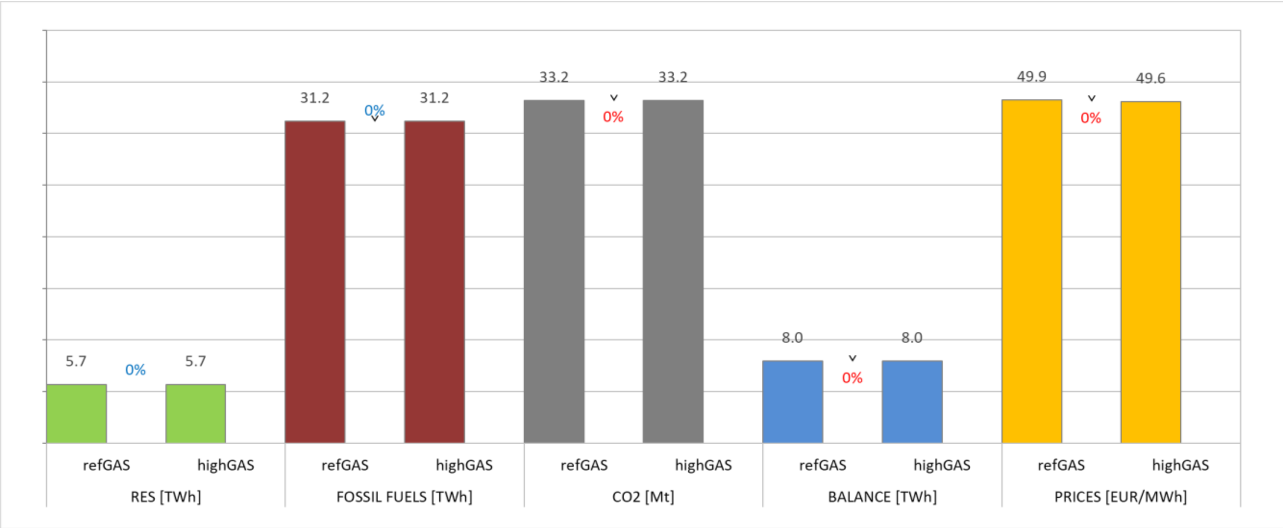
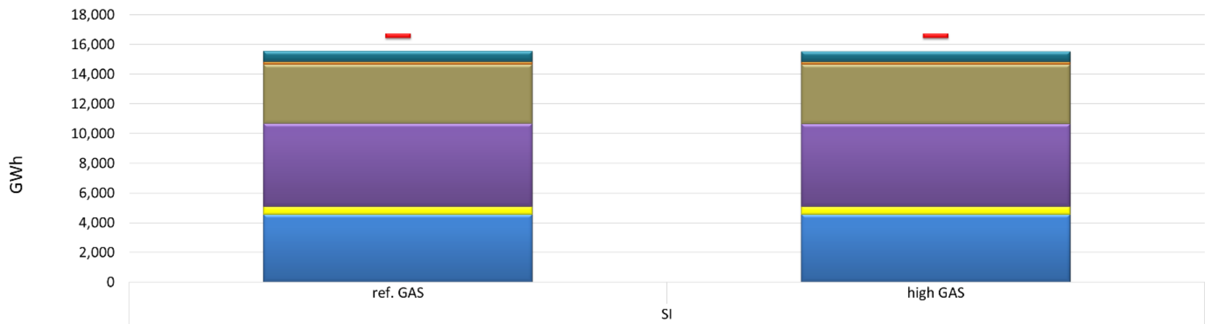


Figure 137: Main system operating indicators in EMS market area in 2030 - ref. GAS vs high GAS

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

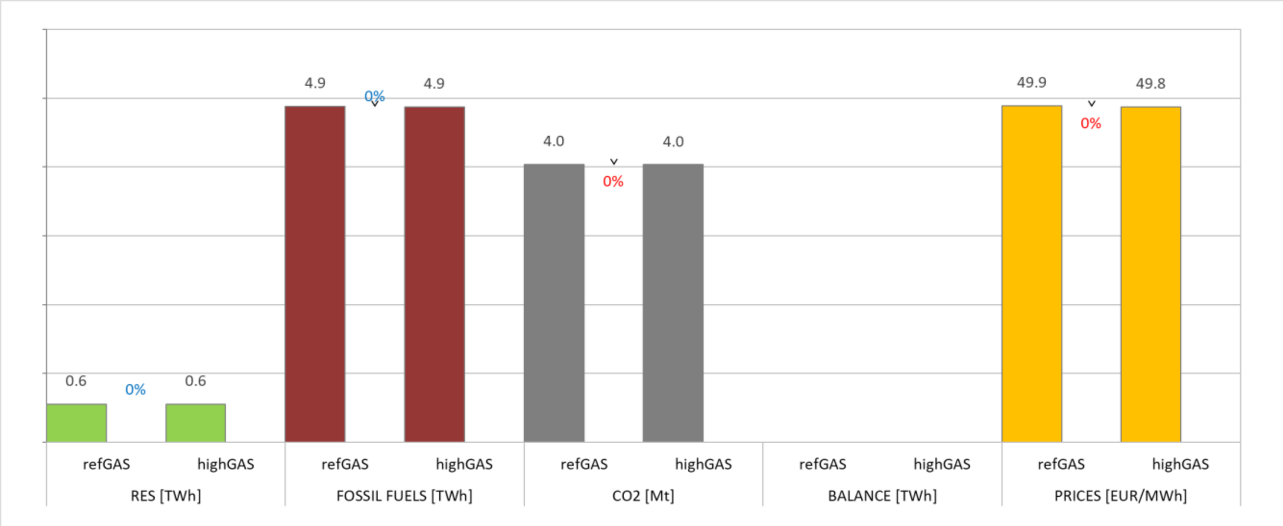
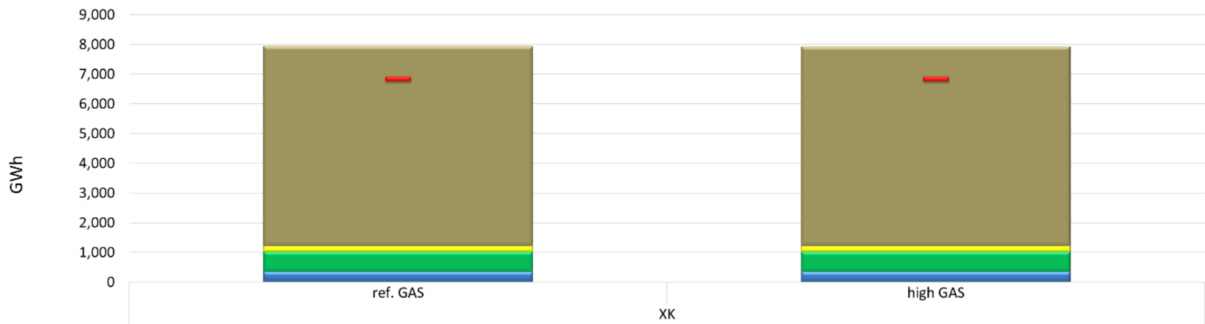


Figure 139: Main system operating indicators in ELES market area in 2030 - ref. GAS vs high GAS

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

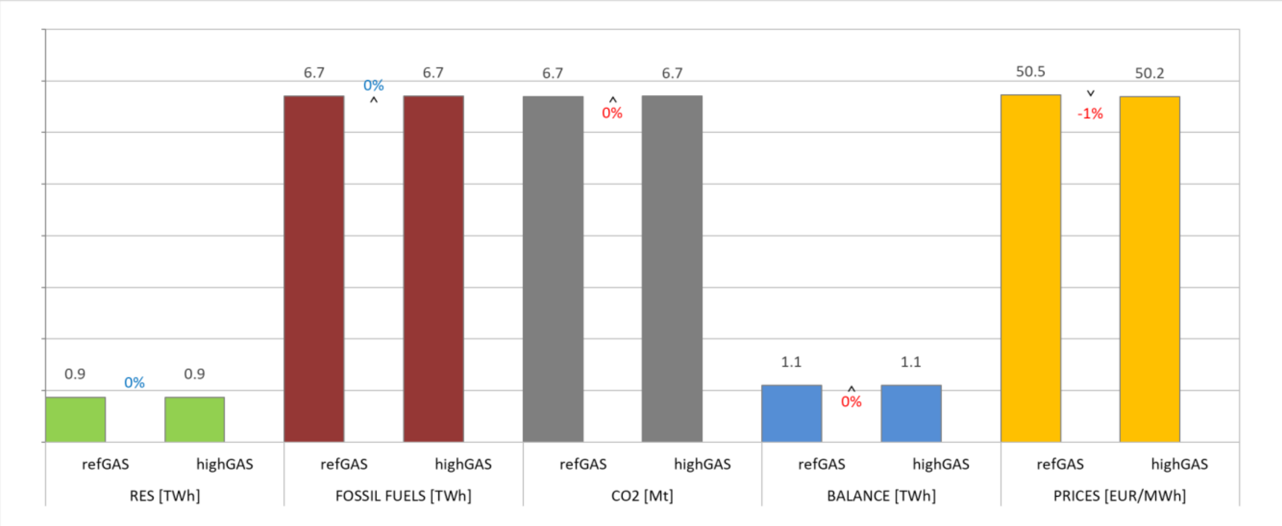


Figure 141: Main system operating indicators in KOSTT market area in 2030 - ref. GAS vs high GAS

6. NETWORK ANALYSES RESULTS

The results of detailed regional power network analyses are given in this Chapter. It is focused on 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 market results from Antares software into PSS/E network simulator. For this exercise we had to develop and test adequate numerous procedures and scritps, since these two software are not directly linked and compatible. It was quite challenging and time consuming task.

Finally, we managed to create robust and verified regional power system model consisting of:

- **8578 buses**
- **10050 branches**
- **3360 loads**
- **1521 power plants**
- **3745 transformers**
- **149 switched shunts**
- **4 DC lines**

This model is then adapted and analyzed in 11 scenarios (10 regular scenarios and additional natural gas scenario). Each scenario is run 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 PSS/E network analyses. There are hundreds of pages of PSS/E outputs for selected network scenarios. However, we don't need all details to be given here, but at the same time we shouldn't lose any important result. That's why the network analyses results will be presented for each scenario on 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 400 and 220 kV level

4. Voltage profiles on 400 and 220 kV level
5. Critical network outages and consequent overloadings (n-1 analysis)

Finally, as a recap of the network analyses the following regional overview is given for all scenarios together:

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

In addition, the main recap is also given on the country level. Final recapitulation and comparison between diffrent network scenarios gives clear overview of high RES impact on transmission network operation both on the regional and individual country level.

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

The first indicator here is the area summary report. It is used to show summary data for each of selected areas. Area summary for the first network scenario is given as follows:

	FROM ------AT AREA BUSES-------					TO				-NET INTERCHANGE-		
	GENE-	FROM IND	TO IND	TO	TO BUS	GNE BUS	TO LINE	FROM	TO	TO TIE	TO TIES	DESIRED
X-- AREA --X	RATION	GENERATN	MOTORS	LOAD	SHUNT	DEVICES	SHUNT	CHARGING	LOSSES	LINES	+ LOADS	NET INT
10	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 142: Area summary report in scenario 1

This regime refers to January, 16th at 6 pm.

In this scenario total regional load is 42136 MW, while total generation is 52432 MW. Clearly, the largest net exporters in the region in scenario 1 are Romania (4462 MW) and Serbia (2972 MW), while the largest importer is Greece (-906 MW). In total, in scenario 1, EMI region has a surplus of 8717 MW.

The following figure shows cross-border power exchange map for scenario 1 with maximum load, referent CO_2 and referent RES. This is scenario with the biggest regional export. Through HVDC submarine cables to Italy in this scenario, SEE is exporting 1000 MW (ME-IT) + 500 MW (GR – IT). Besides that, we notice significant additional exchange to Italy from Slovenia (789 MW). On the other side, more than 1500 MW is exported to Turkey.

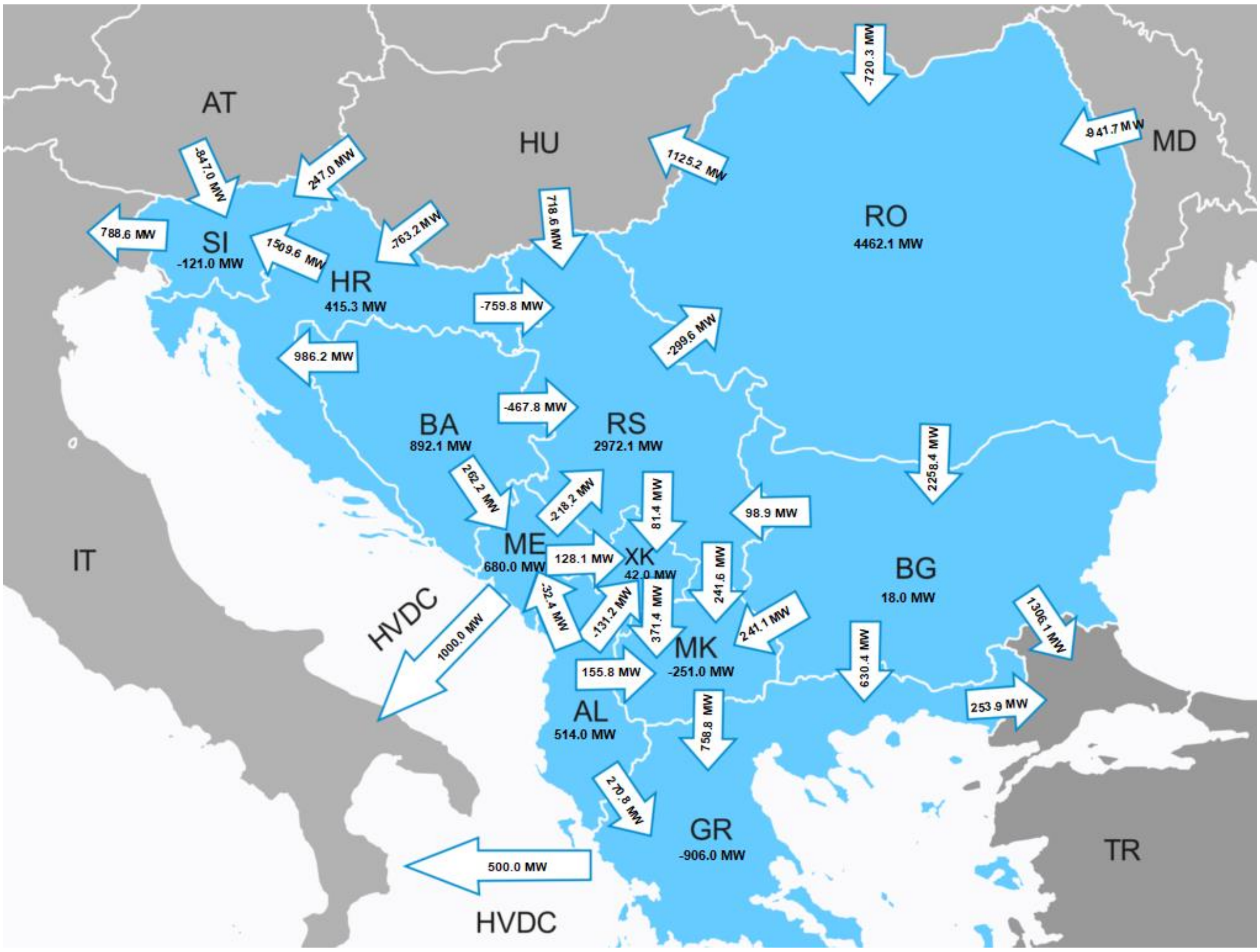


Figure 143: Cross-border exhanges (MW) and directions between the countries in scenario 1: Base case, maximum load, referent CO_2 and referent RES

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

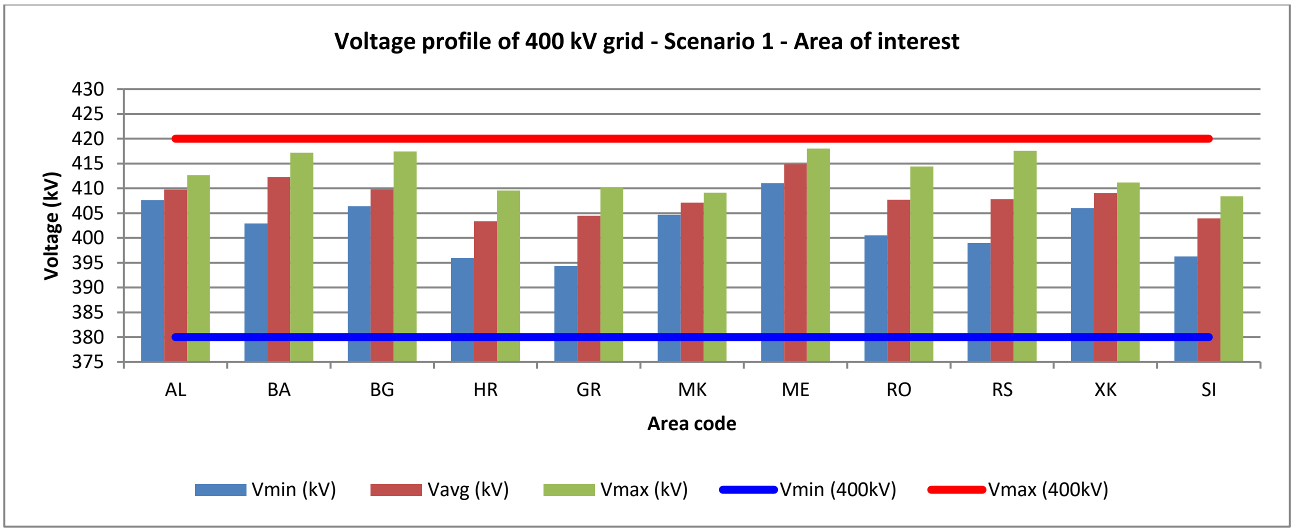


Figure 144: 400 kV voltage profiles (minimum, maximum and average) per country in scenario 1 (base case, maximum load, referent CO_2 and referent RES)

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

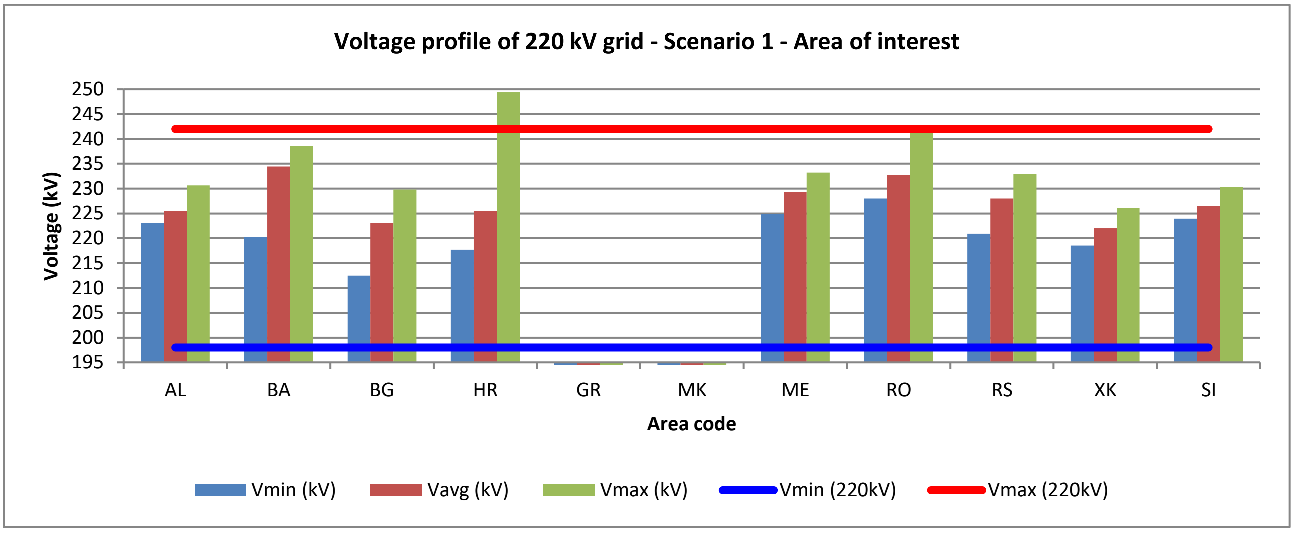


Figure 145: 220 kV voltage profiles (minimum, maximum and average) per country in scenario 1 (base case, maximum load, referent CO_2 and referent RES)

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

Contingency n-1 analysis report for scenario 1 is given 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 147: Contingency (n-1) analysis report for scenario 1

Clearly, in the base case (scenario 1) there are 16 contingency events. There are 4 cases with overloadings higher than 130% (given above in red). In the base case with all elements available 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 overloaded element in all other outages.

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

Area summary for the second network scenario is given as follows:

FROM ------AT AREA BUSES-------				TO					-NET INTERCHANGE-			
X-- AREA --X	GENE-RATION	FROM IND GENERATN	TO IND MOTORS	TO LOAD	TO BUS SHUNT	GNE BUS DEVICES	TO LINE SHUNT	FROM CHARGING	TO LOSSES	TO TIE LINES	TO TIES + LOADS	DESIRED NET INT
10	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 148: Area summary report in scenario 2

This regime refers to May 6th, 4am.

With the minimum load (scenario 2) total regional load is significantly lower 21530 MW (51% of the max load in scenario 1 with 42136 MW), while total generation is 20956 MW (compared to max load regime with 52432 MW). The largest net exporters in the region in scenario 2 are Romania again (1208 MW) and Bulgaria (1146 MW), while the largest importer is again Greece (-2290 MW). In total, region has a deficit of -1377 MW.

The following Figure shows cross-border power exchange map. HVDC submarine cables to Italy in this scenario are now transferring power in this opposite direction in comparions with scenario 1 – from Italy to SEE. On the other side, export to Turkey remains the same, around 1500 MW.

Figure 149: Cross-border exhanges (MW) and directions between the countries in scenario: Base case, minimum load, referent CO_2 and referent RES

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

As expected, in minimum load regime, 400 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.

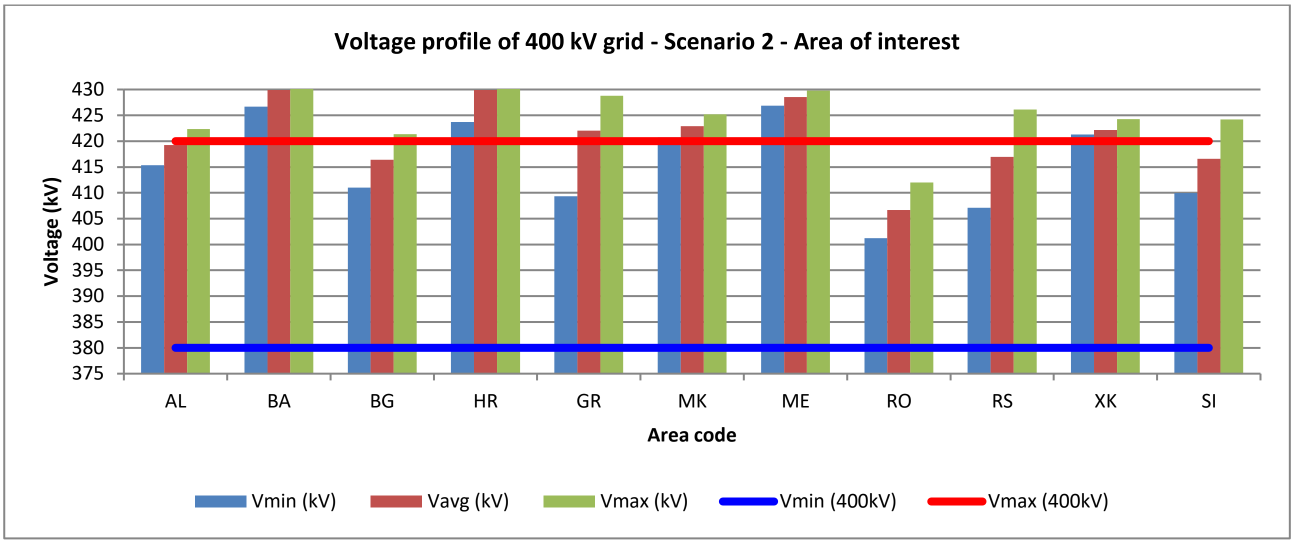


Figure 150: 400 kV voltage profiles (minimum, maximum and average) per country in scenario 2 (base case, minimum load, referent CO_2 and referent RES)

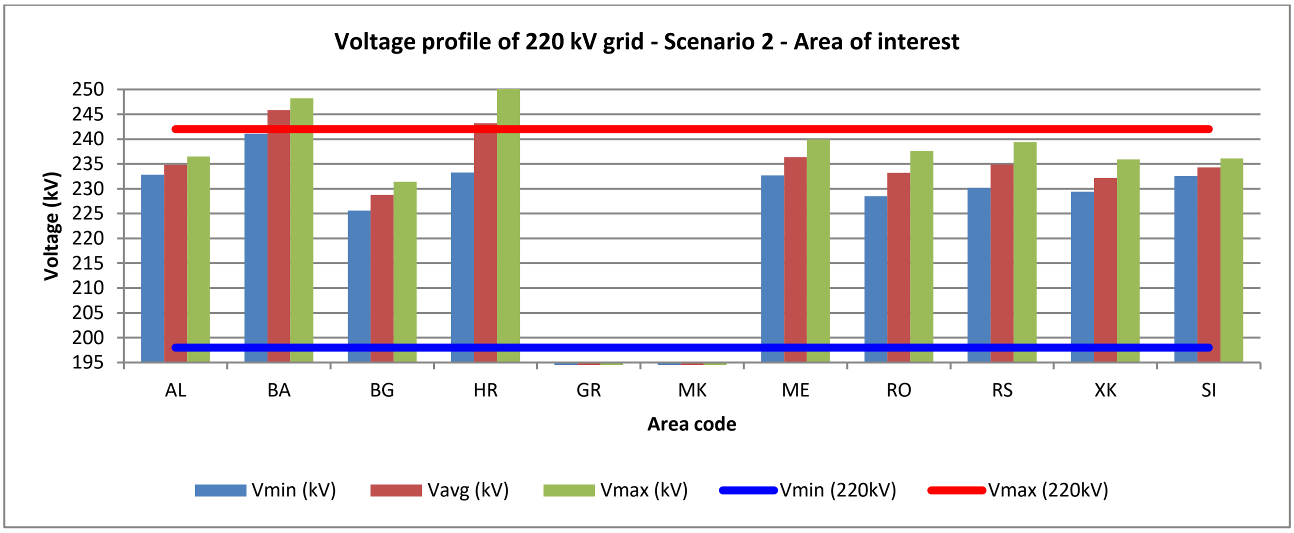


Figure 151: 220 kV voltage profiles (minimum, maximum and average) per country in scenario 2 (base case, minimum load, referent CO_2 and referent RES)

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	[0LASTV11 400.00]	1000.00	-50.00	1001.25	1108.50	84.18

Figure 152: List of 400 and 220 kV elements loaded more than 80% in scenario 2

In this scenario there are just 3 heavily loaded elements (all three are interconnections), but none is overloaded, not even 400 kV Rosiori – Mukacevo that was slightly above the limit in scenario 1.

Finally, contingency N-1 analysis results for this scenarios is given 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 153: Contingency (n-1) analysis report for scenario 2

In scenario 2 with minimum system load there are 8 contingency events that provoke overloading or voltage out of limits. Among them there are no severe overloadings (higher than 130%).

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

Area summary for the third network scenario (high RES, low demand growth, referent CO_2 and minimum load) is given as follows:

	FROM ------AT AREA BUSES-------				TO					-NET INTERCHANGE-		
X-- AREA --X	GENE- RATION	FROM IND GENERATN	TO IND MOTORS	TO LOAD	TO BUS SHUNT	GNE BUS DEVICES	TO LINE SHUNT	FROM CHARGING	TO LOSSES	TO TIE LINES	TO TIES + LOADS	DESIRED NET INT
10	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 154: Area summary report in scenario 3

This regime refers to May 6th, 4am.

With the minimum load in scenario 3 total regional load is 20424 MW, while total generation is 20220 MW. In total, regional countries have a deficit of -1002 MW. The largest net exporters in the region in scenario 2 are again Bulgaria (1328 MW) and Romania (783 MW) and, while the largest importer is again Greece (-2290 MW).

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

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

Figure 155: Cross-border exhanges (MW) and directions between the countries in scenario 2: high RES, low demand growth, referent CO_2 and minimum load

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

This is expected situation, since this scenario represent case with minimum load and case of lower demand growth. In such case, expected minimum load is lower than expected, so the most of lines are very low loaded thus generating reactive power from chargings.

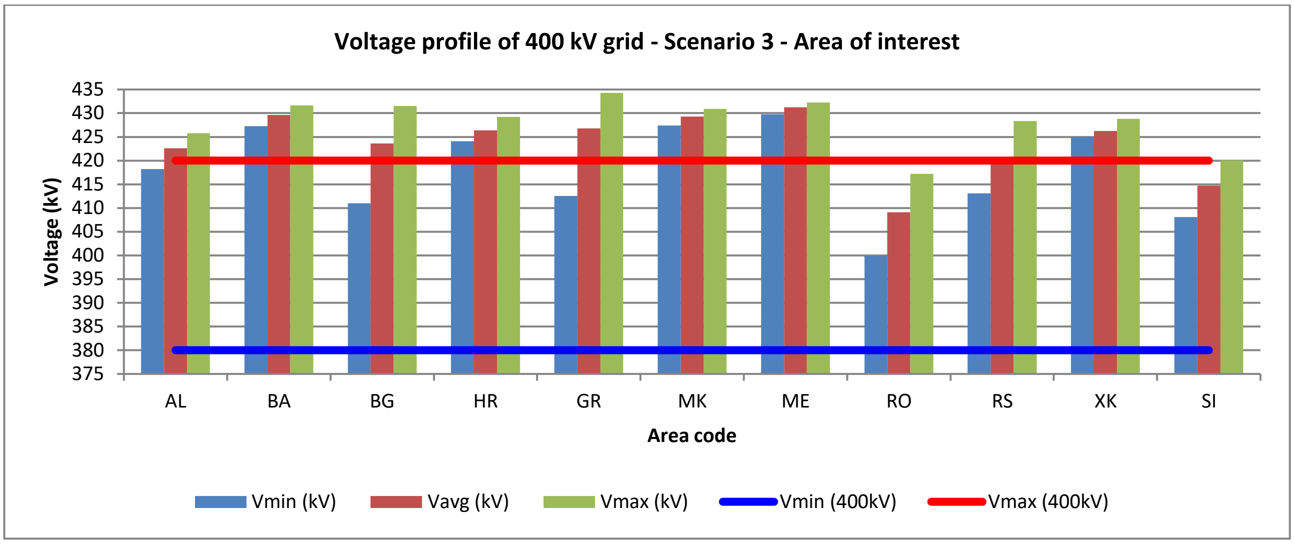


Figure 156: 400 kV voltage profiles (minimum, maximum and average) per country in scenario 3: high RES, low demand growth, referent CO_2 and minimum load

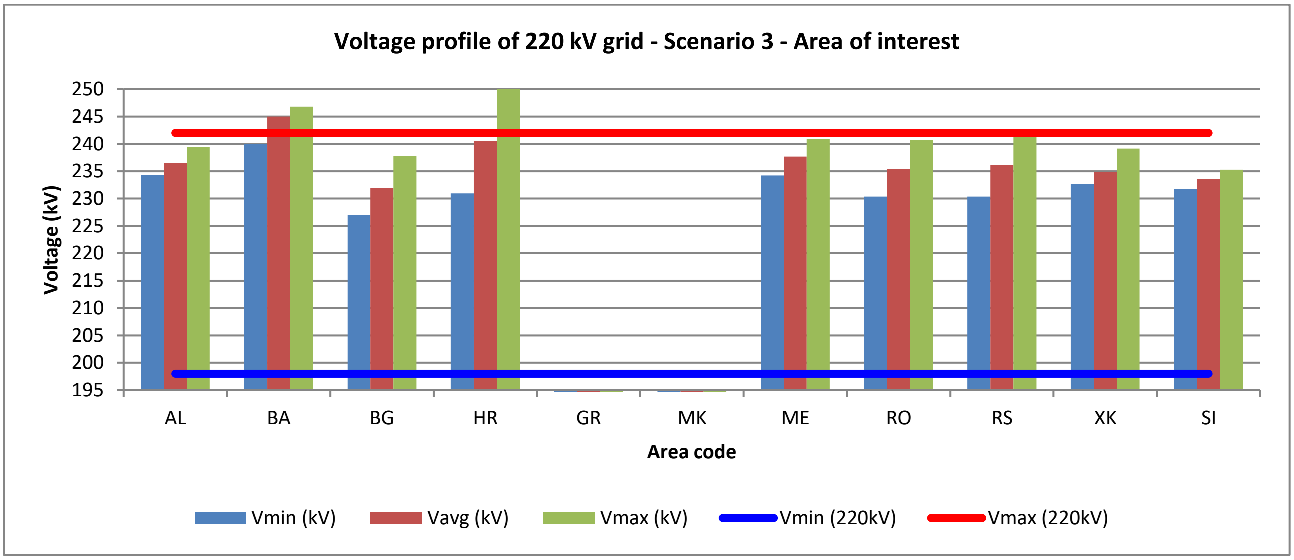


Figure 157: 220 kV voltage profiles (minimum, maximum and average) per country in scenario 3: high RES, low demand growth, referent CO_2 and minimum load

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]	631.92	-97.80	639.44	692.80	89.38

Figure 158: List of 400 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%: interconnection Mukacevo (UA) – Rosiori (RO) (89%).

Finally, contingency N-1 analysis results for this scenarios is given 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 159: Contingency (n-1) analysis report for scenario 3

In scenario 3 there are 3 contingency events. There are 2 cases with overloadings higher than 130% (given above in red). In the base case with all elements available interconnection line Rosiori (Ro) – 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

Area summary for the fourth network scenario (high RES, low demand growth, referent CO_2 and maximum RES) is given as follows:

FROM	------AT AREA BUSES-------			TO				-NET INTERCHANGE-				
	GENE-	FROM IND	TO IND	TO	TO BUS	GNE BUS	TO LINE	FROM	TO	TO TIE	TO TIES	DESIRED
X-- AREA --X	RATION	GENERATN	MOTORS	LOAD	SHUNT	DEVICES	SHUNT	CHARGING	LOSSES	LINES	+ LOADS	NET INT
10	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 160: Area summary report in scenario 4

This regime refers to March 24th, 11am.

In this scenario total regional load is 36068 MW, while total generation is 40096 MW. The largest net exporters in the region in scenario 4 are Romania (4575 MW) and Greece (3310 MW), while the largest importer is Serbia (-3024 MW). In total, in scenario 4, EMI region has a surplus of 2490 MW.

So, in this scenario EMI region is exporting, but it is interesting to note that usual exporter Bulgaria is importing and usual importer Greece is exporting. It is expected having in mind 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 cross-border power exchange map for high RES, low demand growth, referent CO_2 and maximum RES scenario.

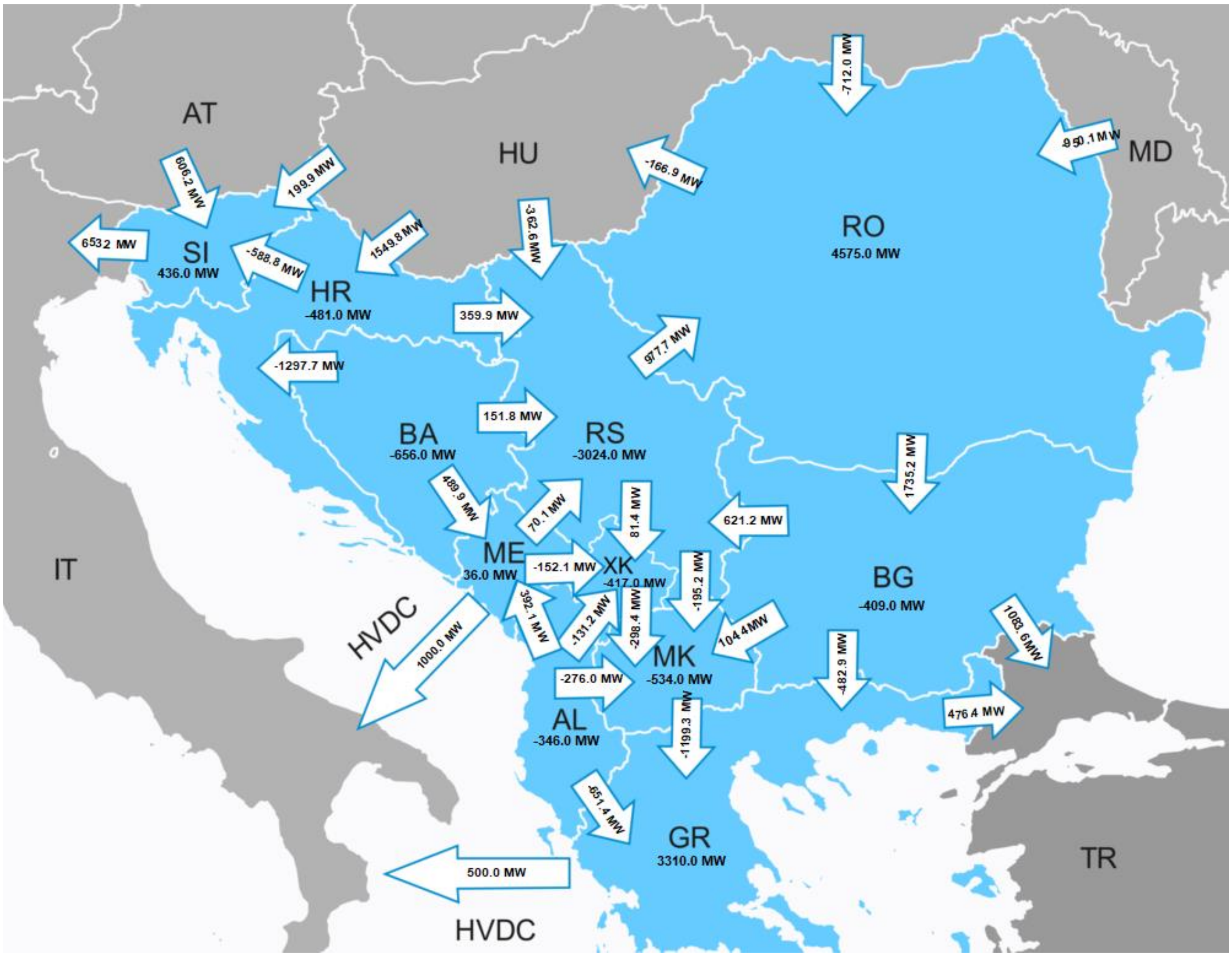


Figure 161: Cross-border exhanges (MW) and directions between the countries in scenario: high RES, low demand growth, referent CO_2 and maximum RES

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

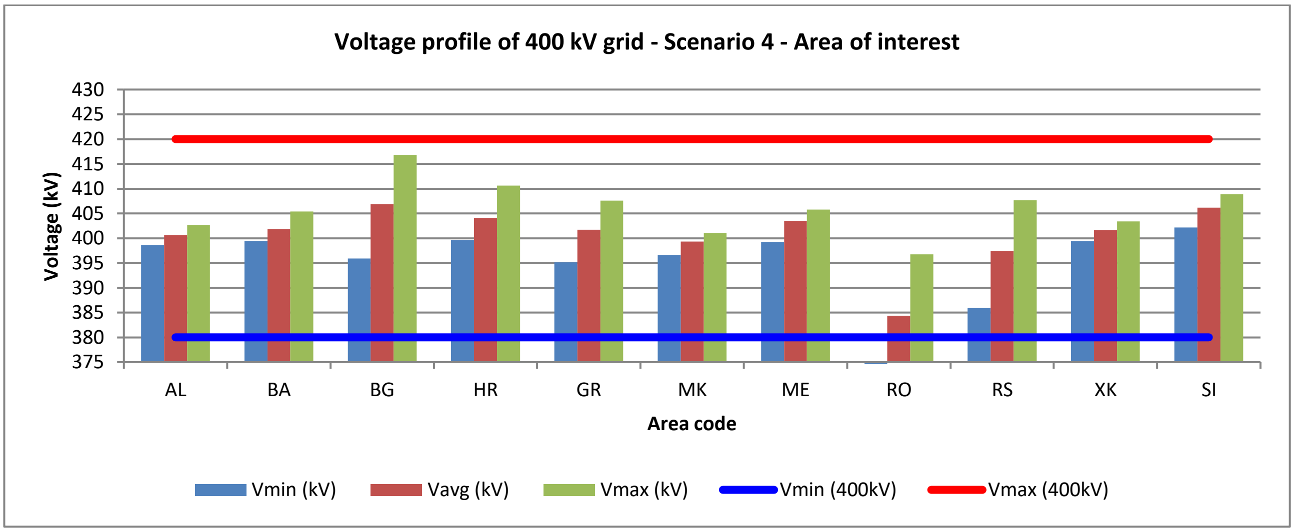


Figure 162: 400 kV voltage profiles (minimum, maximum and average) per country in scenario 4: high RES, low demand growth, referent CO_2 and maximum RES

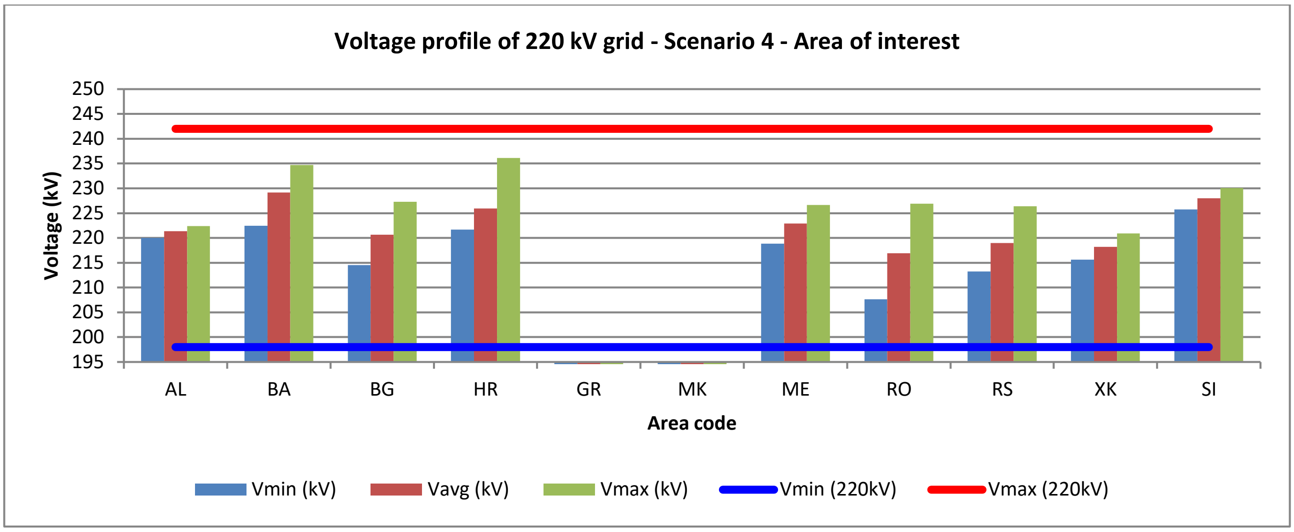


Figure 163: 220 kV voltage profiles (minimum, maximum and average) per country in scenario 4: high RES, low demand growth, referent CO_2 and maximum RES

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

In scenario 4 there are just 2 elements in the region with the loading above 80%, both Romanian interconnections: to Ukraine (112%) and to Serbia (80%).

Finally, contingency N-1 analysis results for this scenarios is given 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 165: Contingency (n-1) analysis report for scenario 4

In scenario 4 there are 5 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 interconnection line Rosiori (Ro) – 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

Area summary for the fifth network scenario (high RES, low demand growth, referent CO_2 and maximum WPP and HPP) is given as follows:

FROM ------AT AREA BUSES------- X-- AREA --X	GENE- RATION	FROM IND GENERATN	TO IND MOTORS	TO TO LOAD	TO BUS SHUNT	GNE BUS DEVICES	TO LINE SHUNT	-NET INTERCHANGE- FROM CHARGING	TO LOSSES	TO TIE LINES	TO TIES + LOADS	DESIRED 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 166: Area summary report in scenario 5

This regime refers to March 22th, 7pm.

In this scenario region is exporting, but the situation around exporters and importers is as expected. The reason is that this regime refers to evening hour (7 pm) when SPP generation is low while the system load is close to its peak.

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

Figure 167: Cross-border exhanges (MW) and directions between the countries in scenario: high RES, low demand growth, referent CO_2 and maximum WPP and HPP

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

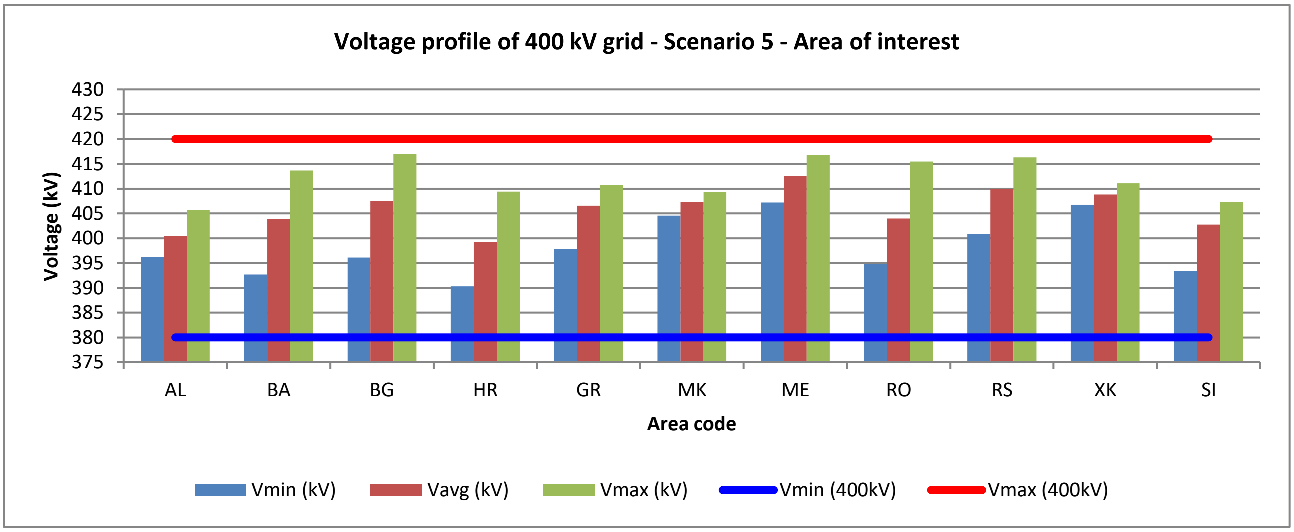


Figure 168: 400 kV voltage profiles (minimum, maximum and average) per country in scenario 5: high RES, low demand growth, referent CO_2 and maximum RES

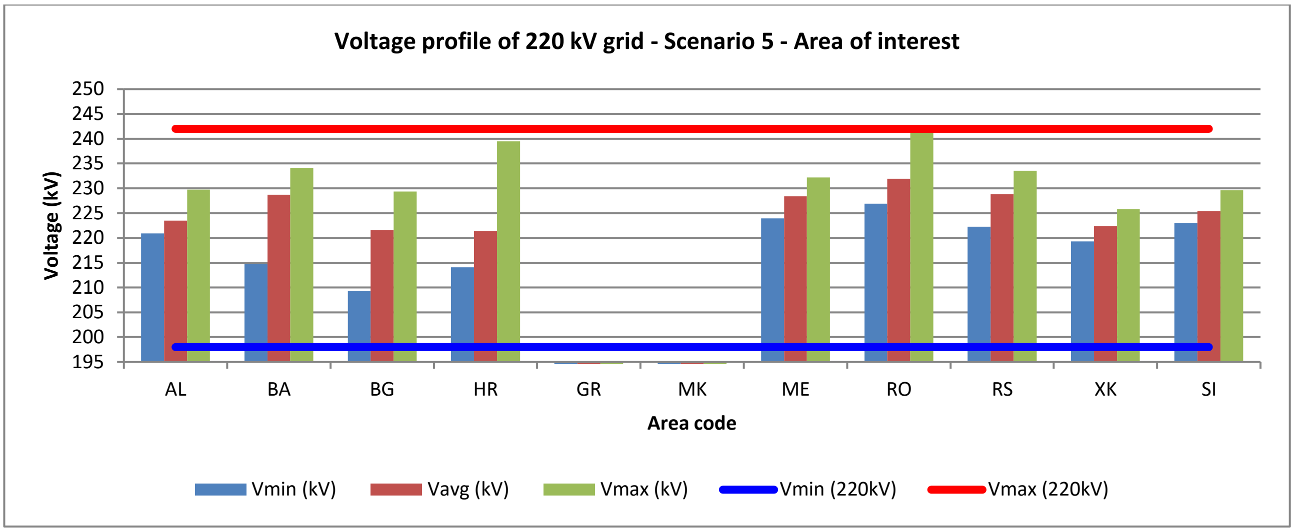


Figure 169: 220 kV voltage profiles (minimum, maximum and average) per country in scenario 5: high RES, low demand growth, referent CO_2 and maximum WPP and HPP

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

In scenario 5 there are 4 elements in the region with the loading above 80%, but not more than 86%.

Finally, contingency N-1 analysis results for this scenarios is given on the following page.

In scenario 5 there are 3 contingency events. There are 5 cases with overloadings higher than 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 171: Contingency (n-1) analysis report for scenario 5

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

Area summary for the sixth network scenario (high RES, low demand growth, referent CO_2 and maximum SPP) is given as follows:

FROM ------AT AREA BUSES------- X-- AREA --X	GENE-RATION	FROM IND GENERATN	TO IND MOTORS	TO LOAD	TO BUS SHUNT	GNE BUS DEVICES	TO LINE SHUNT	-NET INTERCHANGE- FROM CHARGING	TO LOSSES	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 172: Area summary report in scenario 6

This regime refers to April 23th, 12am.

In this scenario total regional load is 30189 MW, while total generation is 32224 MW. The largest net exporters in the region in scenario 6 are again: Romania (1964 MW), Greece (2180 MW) and Bulgaria (1427 MW), while the largest importer is Serbia (-2784 MW). In total, in scenario 6, EMI region has a surplus of just 1097 MW.

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

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

Figure 173: Cross-border exhanges (MW) and directions between the countries in scenario: high RES, low demand growth, referent CO_2 and maximum SPP

The following two figures show 400 and 220 kV voltage profiles in each country with maximum, minimum and average values in each country. All voltages in the region are within limits, except few cases in 400 kV netwotk in Bulgaria and 220 kV in Croatia with voltages slightly above the limit.

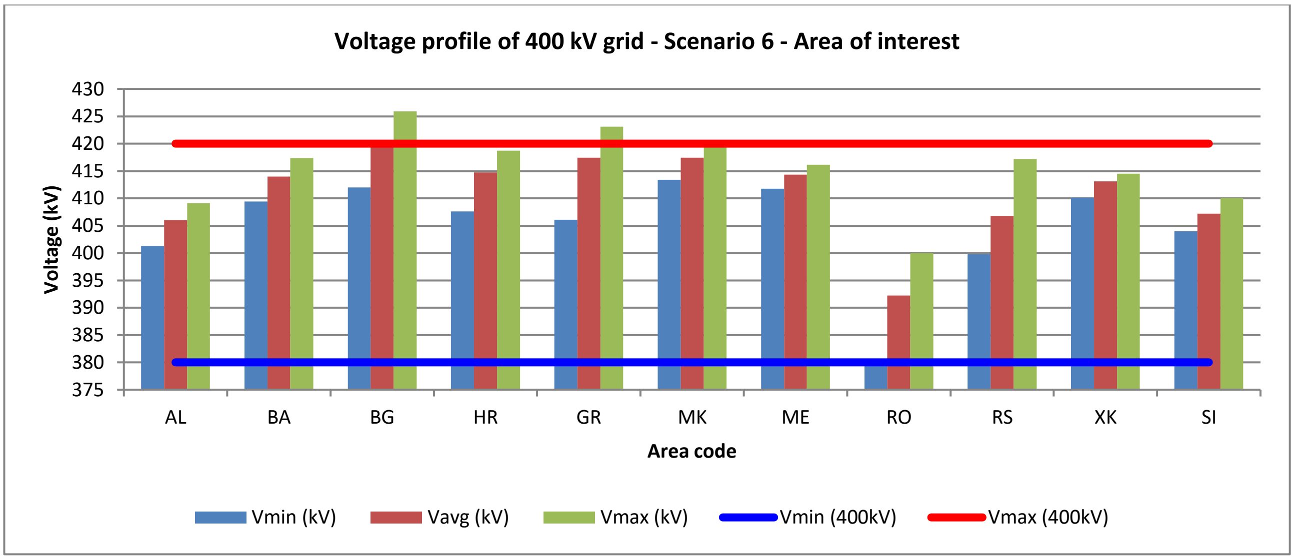


Figure 174: 400 kV voltage profiles (minimum, maximum and average) per country in scenario 6: high RES, low demand growth, referent CO_2 and maximum SPP

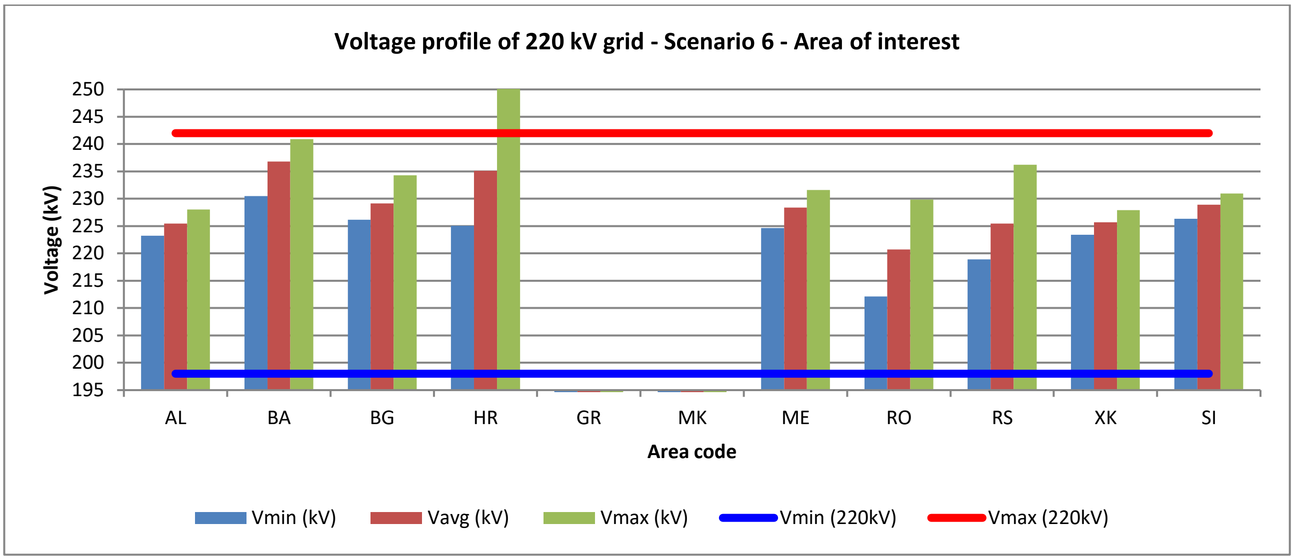


Figure 175: 220 kV voltage profiles (minimum, maximum and average) per country in scenario 6: high RES, low demand growth, referent CO_2 and maximum SPP

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]	784.87	-277.41	832.46	692.80	121.93

Figure 176: List of 400 and 220 kV elements loaded more than 80% in scenario 6

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

Finally, contingency N-1 analysis results for this scenarios is given as follows.

```
<----------------- 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 177: Contingency (n-1) analysis report for scenario 6

In scenario 6 there is just 1 contingency events. There are no cases with overloadings higher than 130%. In the base case with all elements available 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

Area summary for the seventh network scenario (high RES, low demand growth, alternative CO_2 and mimimum load) is given as follows:

FROM	------AT AREA BUSES-------			TO					-NET INTERCHANGE-			
	GENE-	FROM IND	TO IND	TO	TO BUS	GNE BUS	TO LINE	FROM	TO	TO TIE	TO TIES	DESIRED
X-- AREA --X	RATION	GENERATN	MOTORS	LOAD	SHUNT	DEVICES	SHUNT	CHARGING	LOSSES	LINES	+ LOADS	NET INT
10	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 178: Area summary report in scenario 7

This regime refers to May 6th, 4am.

In this scenario total regional load is very low, just 20185 MW, while total generation is 19572 MW. Most of RES are out of operation and EMI region has a deficit of 1462 MW. The only significant net export in the region in scenario 7 is found in Romania (1133 MW), while the largest importer is Greece (-2290 MW).

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

After that, next two figures show 400 and 220 kV voltage profiles in each country 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 220 kV network voltages are mainly within given limits.

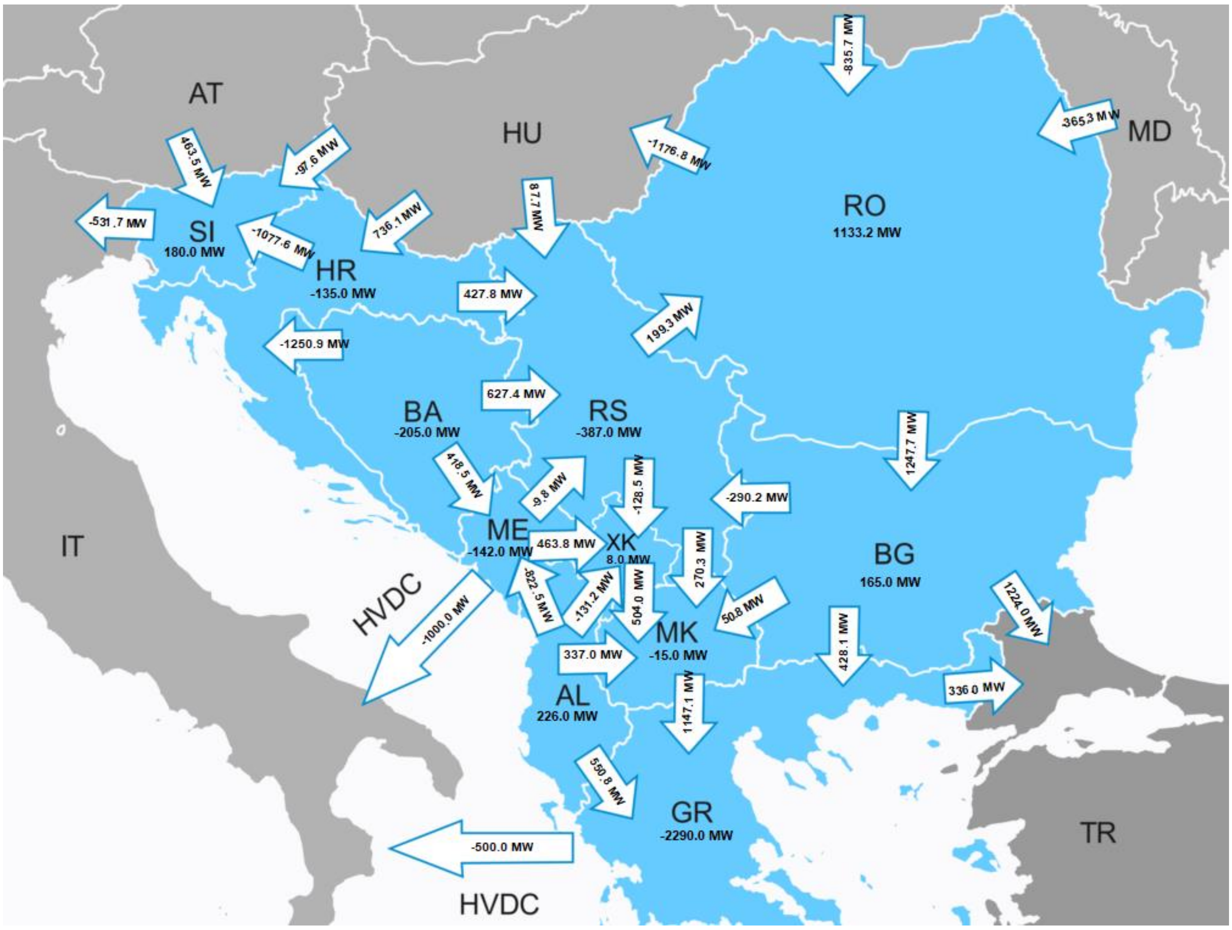


Figure 179: Cross-border exhanges (MW) and directions between the countries in scenario: high RES, low demand growth, alternative CO_2 and mimimum load

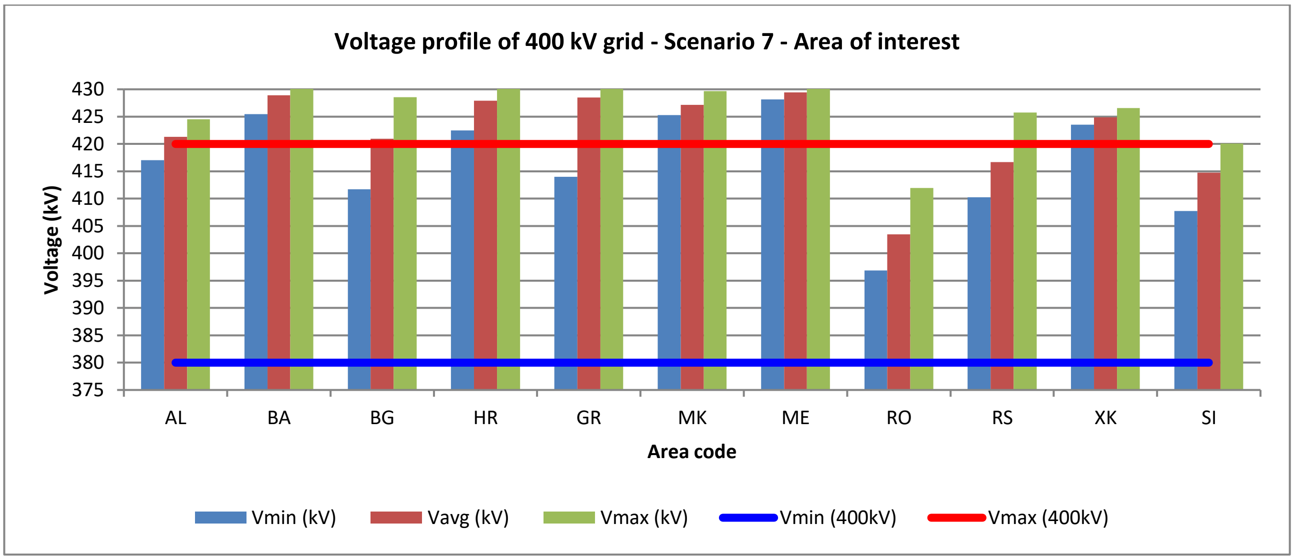


Figure 180: 400 kV voltage profiles (minimum, maximum and average) per country in scenario 7: high RES, low demand growth, alternative CO_2 and mimimum load

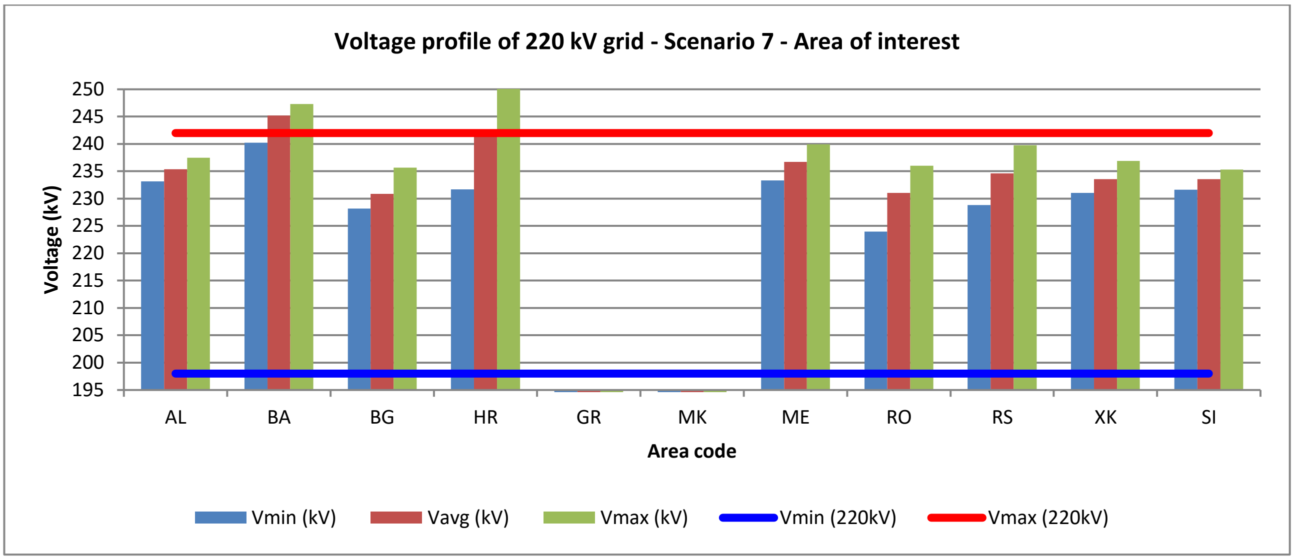


Figure 181: 220 kV voltage profiles (minimum, maximum and average) per country in scenario 7: high RES, low demand growth, alternative CO_2 and mimimum load

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

In scenario 7 there are just 3 elements in the region with the loading above 80%, where Romanian 400 kV interconnection to Ukraine Rosiori - Mukacevo is overloaded (123%). Finally, contingency N-1 analysis results for this scenarios is given as follows.

```
<----------------- 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 183: Contingency (n-1) analysis report for scenario 7

In scenario 7 there are 4 contingency events. However, there are no cases with severe overloading (higher than 130%). In the base case with all elements available interconnection line Rosiori (Ro) – Mukacevo (UA) 400 kV 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

Area summary for the 8th network scenario (high RES, low demand growth, alternative CO_2 and maximum RES) is given as follows:

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	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 184: Area summary report in scenario 8

This regime refers to March 24th, 11am.

In this scenario the region is exporting, but just 740 MW. It is less than in scenario 4 (2490 MW of export) which is similar regime, with max WPP+SPP generation, but with different dispatch of the conventional units due to different level of CO_2 tax. Here again, usual exporter Bulgaria is importing and usual importer Greece is exporting, as in scenario 4. It is expected having in mind 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 load is still low.

The following Figure shows cross-border power exchange map for 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 400 and 220 kV voltage profiles in each country with maximum, minimum and average values in each country. From the voltage profile perspective, this scenarios is perfect – no voltage problems, no voltages out of limits.

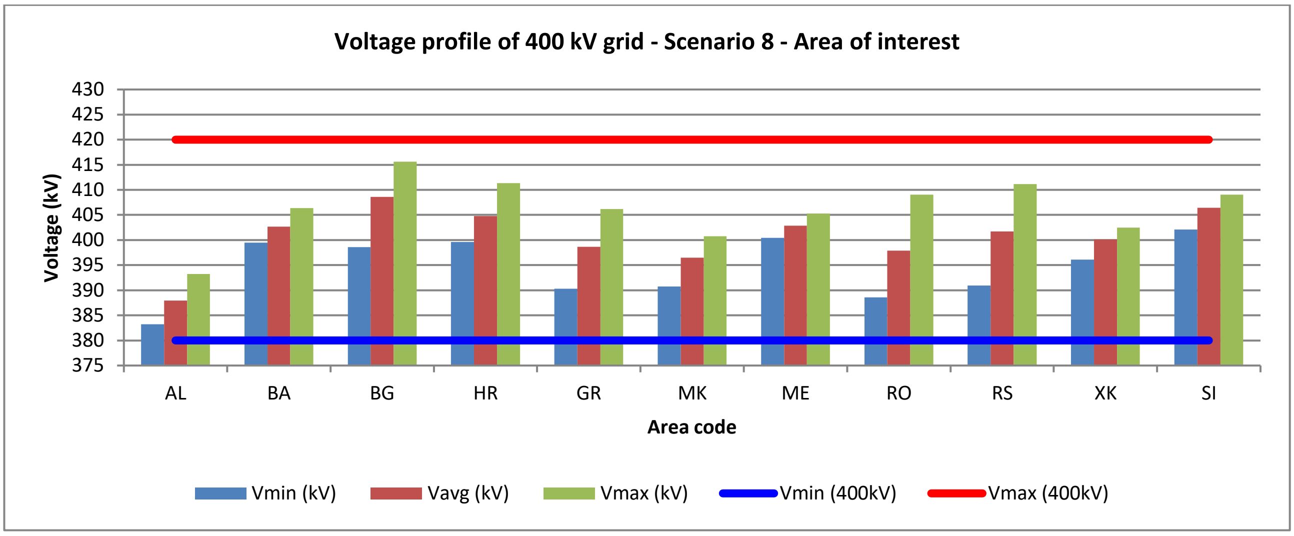


Figure 185: 400 kV voltage profiles (minimum, maximum and average) per country in scenario 8: high RES, low demand growth, alternative CO_2 and maximum RES

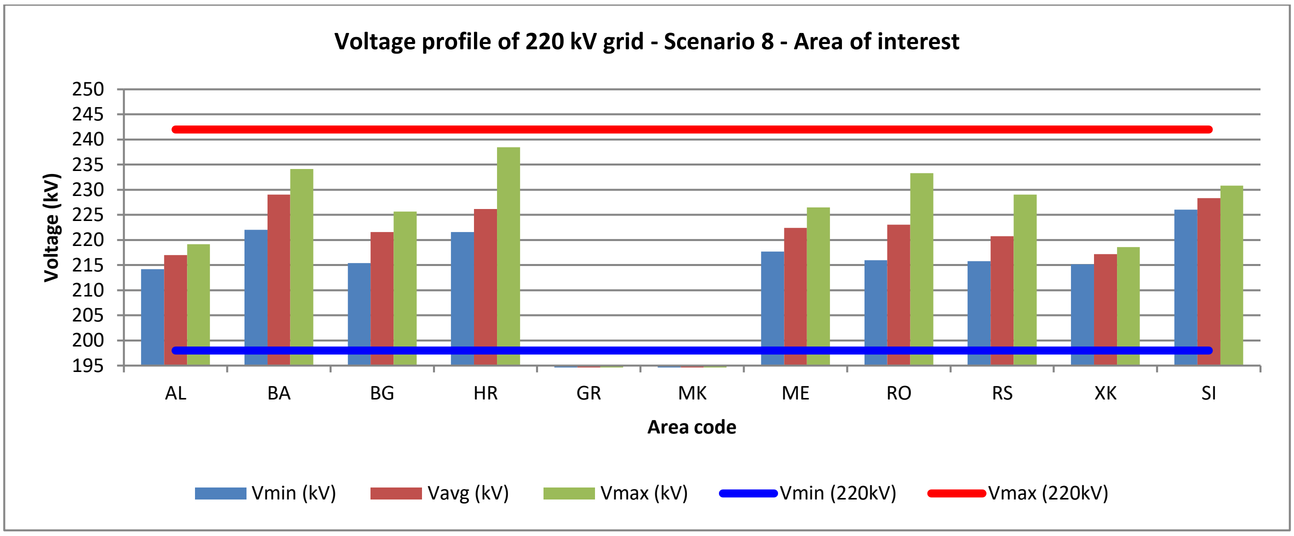


Figure 186: 220 kV voltage profiles (minimum, maximum and average) per country in scenario 8: high RES, low demand growth, alternative CO_2 and maximum RES

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

In scenario 8 there is just 1 elements in the region with the loading above 80% and that is again overhead line 400 kV Rosiori (RO) – Mukacevo (UA) (88%).

Finally, contingency N-1 analysis results for this scenarios is given 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 188: 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

Area summary for the 9th network scenario (high RES, low demand growth, alternative CO_2 and maximum WPP and HPP) is given as follows:

FROM	------AT AREA BUSES-------			TO					-NET INTERCHANGE-			
	GENE-	FROM IND	TO IND	TO	TO BUS	GNE BUS	TO LINE	FROM	TO	TO TIE	TO TIES	DESIRED
X-- AREA --X	RATION	GENERATN	MOTORS	LOAD	SHUNT	DEVICES	SHUNT	CHARGING	LOSSES	LINES	+ LOADS	NET INT
10	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 189: Area summary report in scenario 9

This regime refers to March 20th, 19am.

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

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

Figure 190: Cross-border exhanges (MW) and directions between the countries in scenario: high RES, low demand growth, alternative CO_2 and maximum WPP and HPP

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

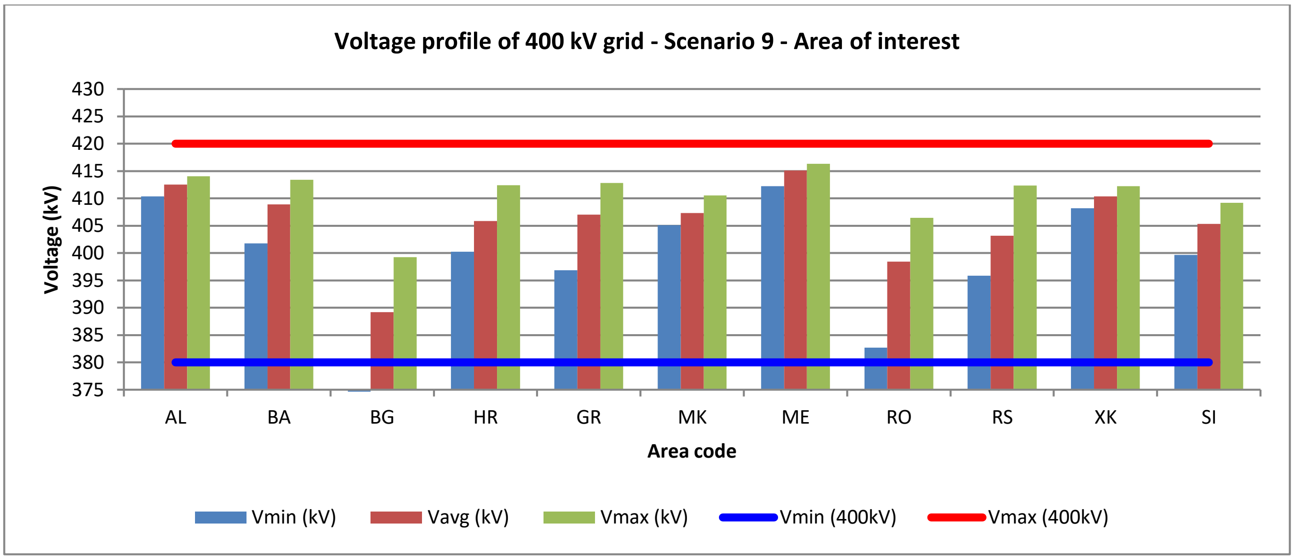


Figure 191: 400 kV voltage profiles (minimum, maximum and average) per country in scenario 9: high RES, low demand growth, alternative CO_2 and maximum WPP and HPP

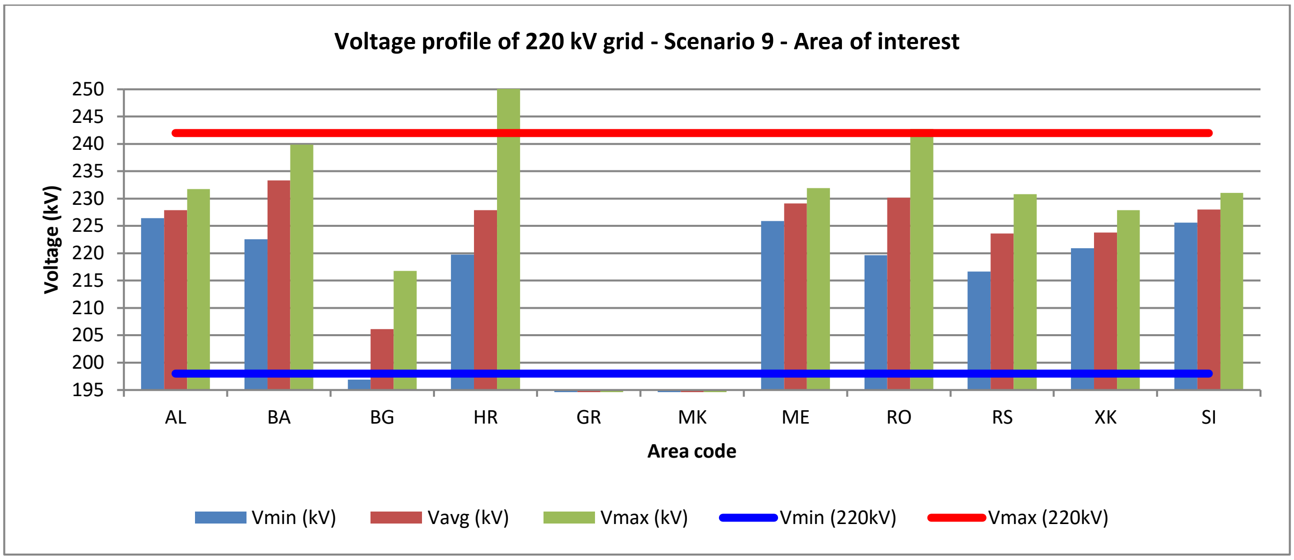


Figure 192: 220 kV voltage profiles (minimum, maximum and average) per country in scenario 9: high RES, low demand growth, alternative CO_2 and maximum WPP and HPP

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

In scenario 9 there are 2 elements in the region with the loading above 80%, both overloaded and both Bulgarian 400 kV interconnections.

Finally, contingency N-1 analysis results for this scenarios is given in the following table. **In scenario 9 there are 12 contingency events.** However, there are 5 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 194: Contingency (n-1) analysis report for scenario 9

6.10. Scenario 10: High RES, low demand growth, alternative CO2 and maximum SPP

Area summary for the 10th network scenario (high RES, low demand growth, alternative CO_2 and maximum SPP) is given as follows:

FROM ------AT AREA BUSES------- X-- AREA --X	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	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 195: Area summary report in scenario 10

This regime refers to April 23th, 12am. This scenario refer to hours around noon and region is exporting, similar to scenario 6.

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

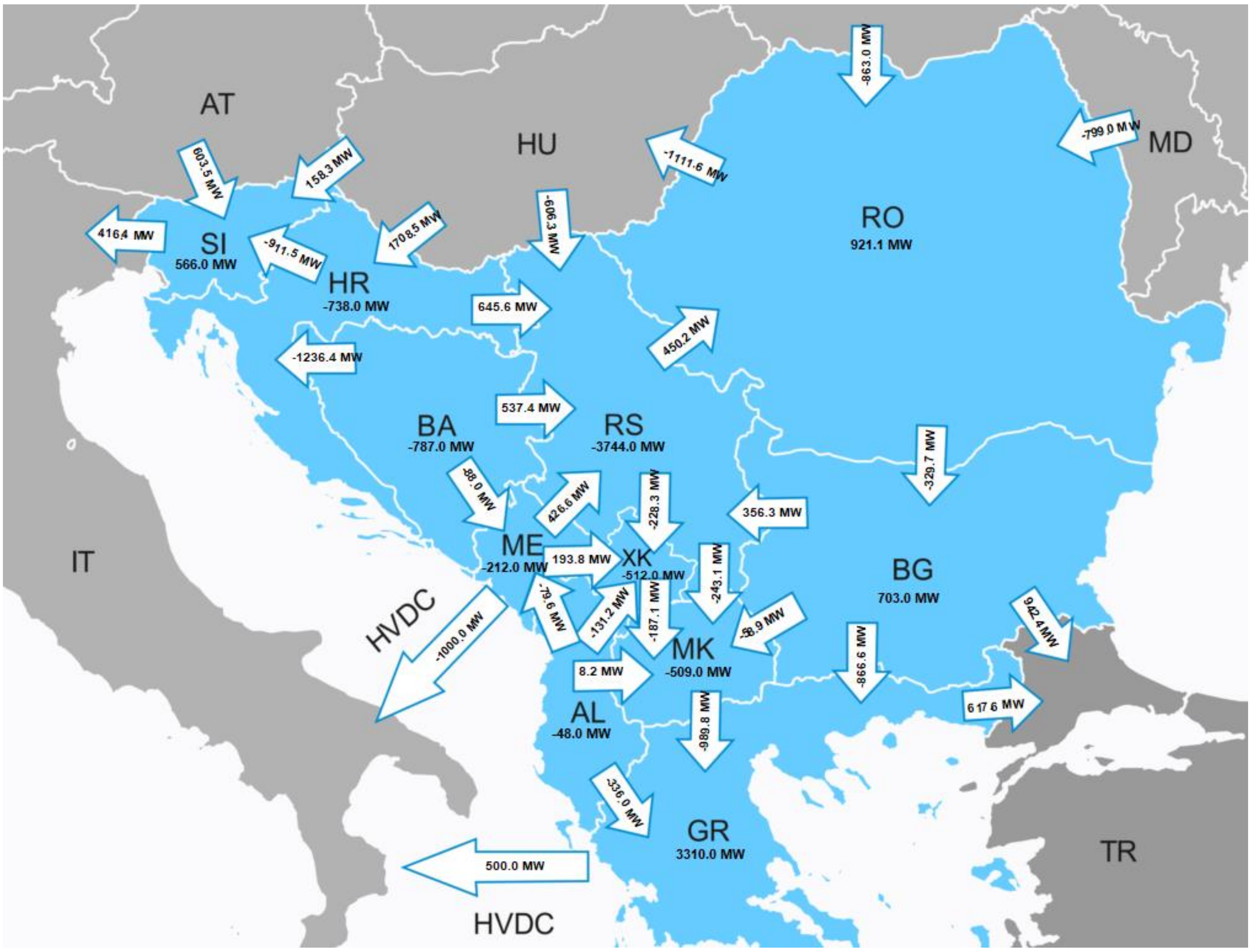


Figure 196: Cross-border exhanges (MW) and directions between the countries in scenario: high RES, low demand growth, alternative CO_2 and maximum SPP

The following two figures show 400 and 220 kV voltages in each country with maximum, minimum and average values in each country. In the last scenario 400 kV voltage profiles are slightly above limits in Bulgaria and N.Macedonia. In 220 kV there are just few light cases in Croatia and Bulgaria.

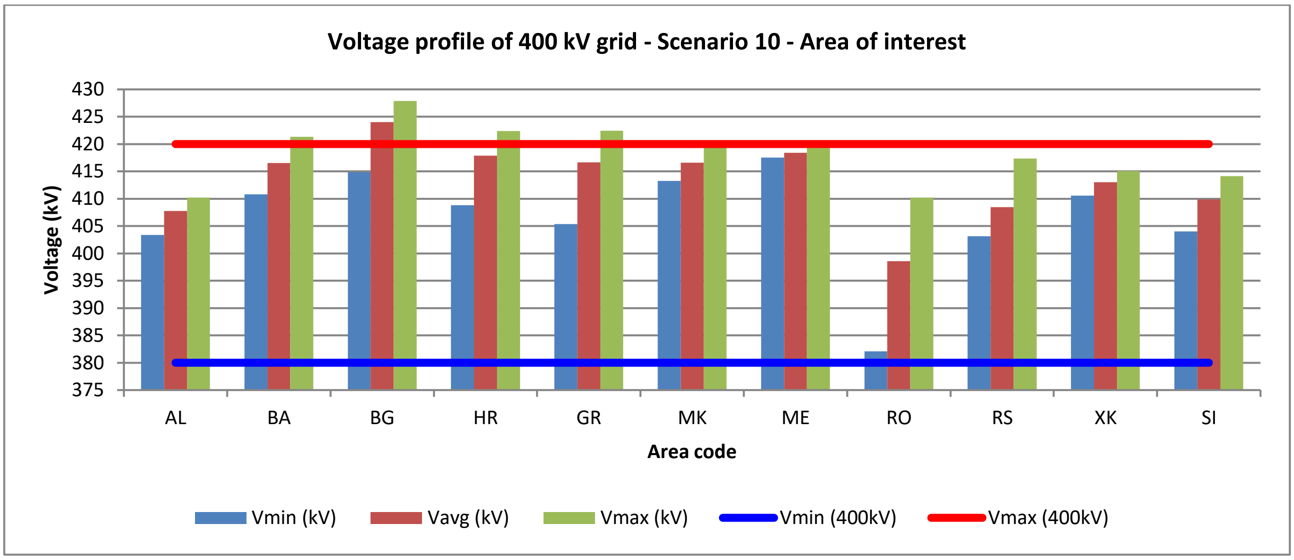


Figure 197: 400 kV voltage profiles (minimum, maximum and average) per country in scenario 10: high RES, low demand growth, alternative CO_2 and maximum SPP

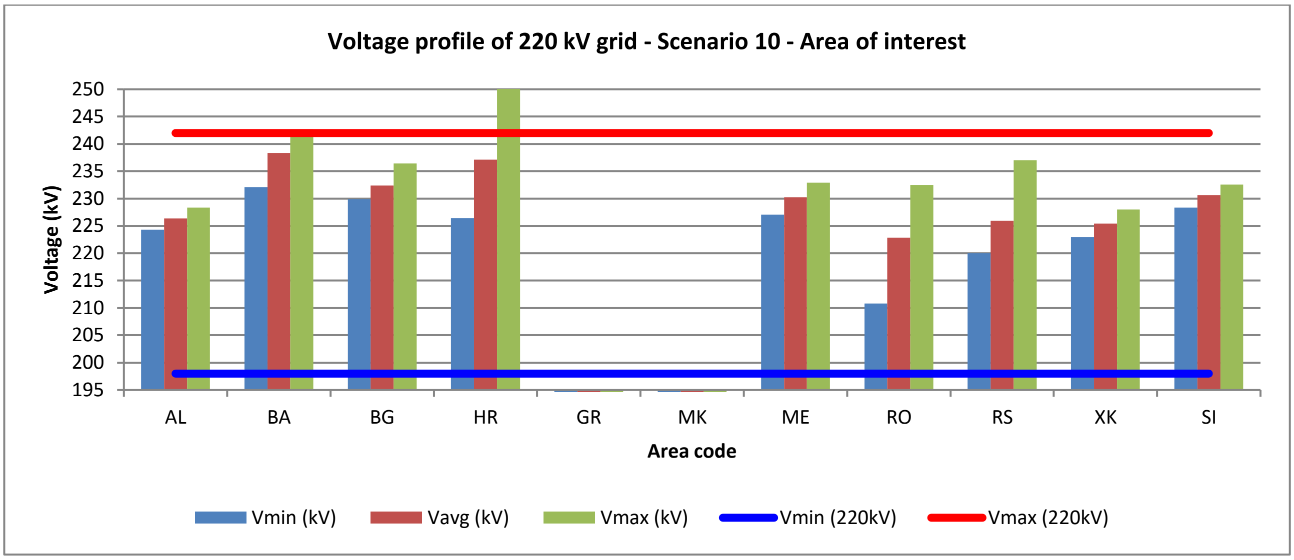


Figure 198: 220 kV voltage profiles (minimum, maximum and average) per country in scenario 10: high RES, low demand growth, alternative CO_2 and maximum SPP

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]	863.02	-285.84	909.13	692.80	133.73

Figure 199: List of 400 and 220 kV elements loaded more than 80% in scenario 10

In scenario 10 there is 1 well known element with the loading above 80% and that is overloaded overhead line 400 kV Rosiori (RO) – Mukacevo (UA) (134%).

Finally, contingency N-1 analysis results for this scenarios is given 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 200: Contingency (n-1) analysis report for scenario 10

In scenario 10 there is 1 contingency event. However, there is just one case with overloading higher than 130% (interconnection between Ukraine and Romania, given above in red), and it happends 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 network scenario as scenario 11, as a follow up on 10 scenarios given in the previous chapter. Area summary for the 11th network scenario is given as follows:

FROM ------AT AREA BUSES-------				TO				-NET INTERCHANGE-				
X-- AREA --X	GENE- RATION	FROM IND GENERATN	TO IND MOTORS	TO LOAD	TO BUS SHUNT	GNE BUS DEVICES	TO LINE SHUNT	FROM CHARGING	TO LOSSES	TO TIE LINES	TO TIES + LOADS	DESIRED NET INT
10	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 201: Area summary report in scenario 11

This regime refers to January 9th, 5pm.

In this scenario total regional load is 45711 MW, while total generation is 53111 MW. Similar to the other scenarios, the largest net exporters in the region are Romania (2971 MW), Serbia (2066 MW) and BiH (1421 MW), while the largest importer is Greece (-1006 MW). In total, in scenario 11, EMI region has a surplus of 5770 MW.

The following Figure shows cross-border power exchange map for gas integration scenario.

Figure 202: Cross-border exhanges (MW) and directions between the countries in gas integration scenario

As given on the following two figures, 400 and 220 kV voltage profiles in the region in this scenario are within limits in all countries, with exception of one 220 kV node in Croatia. In other words, higher level of natural gas integration in the regional power system is not expected to have negative impact on voltage profiles in the region.

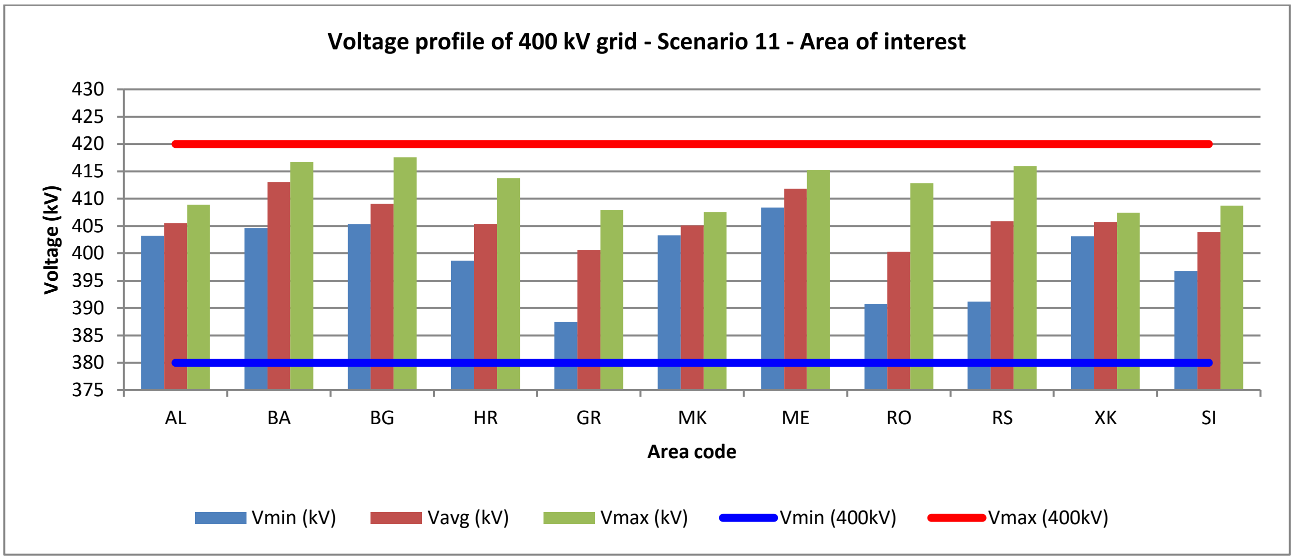


Figure 203: 400 kV voltage profiles (minimum, maximum and average) per country in natural gas scenario

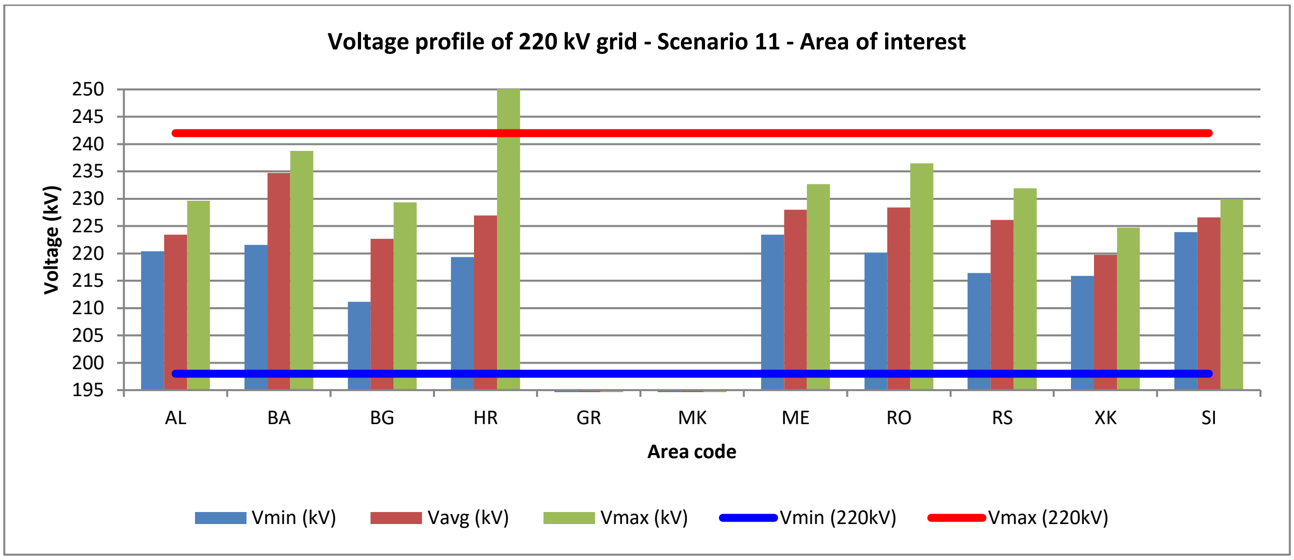


Figure 204: 220 kV voltage profiles (minimum, maximum and average) per country in natural gas scenario

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 205: 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 1 well known element with the loading above 80% and that is overloaded overhead line 400 kV Rosiori (RO) – Mukacevo (UA) (146%).

Finally, contingency N-1 analysis results for this scenarios is given 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 206: 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.

The following conclusions can be taken out separately of the network analysis in high gas integration scenario:

1. **Integration of additional 1155 MW of gas-fired TPPs will have certain impact on the regional transmission network. It will result with 10 network bottlenecks in the region 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. Full comparison of all scenarios is given in the following subchapter.**
3. **Integration of additional 1155 MW of gas-fired TPPs** is not expected to have 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 summarized impact of different RES levels on the network operation in SEE is given:

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 per each analyzed scenario. **Altogether there are 73 contingency cases found in 11 analyzed scenarios. All of it appears 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 Slovenian border to Italy)**
- **11 internal lines and**
- **3 transformers**

8 critical tie lines are found both in 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**

As mentioned before, capacity of 400 kV tie-line Rosiori (RO) – Mukacevo (UA) is set by Ukrainian TSO and it is quite low compared to standard typical values for 400 kV lines. Therefore, this limitation should not be considered as serious limiting factor on the cross-border exchange.

11 critial internal lines are also found both in 400 kV network (3 lines) and 220 kV network (8 lines). These elements are located in the following countries:

- **Albania (2 lines on 220 kV level)**
- **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)**
- **Bulgaria (3 lines, one on 400 kV and 2 on 220 kV level) and**
- **Bosnia and Herzegovina (2 lines on 220 kV)**

3 transformers are detected as critical in the region, two in Croatia, one in Romania[5].

Among all above mentioned 22 critical elements there are 6 elements with severe overloadings (130% of rated current) in one or more scenarios. 3 elements appear to be overloaded in the base cases (with all elements available).

The following figure shows geographical dispersion of critical elements in the EMI region. It seems that **8 out of 11 EMI TSOs can expect to face certain network bottlenecks in high RES scenarios in 2030 (AL, BA, BG, HR, GR, ME, RO and SI). These results show that in given scenarios only TSOs of MK, RS and XK will not face any network bottlenecks with high RES integration as foreseen in this analysis.**

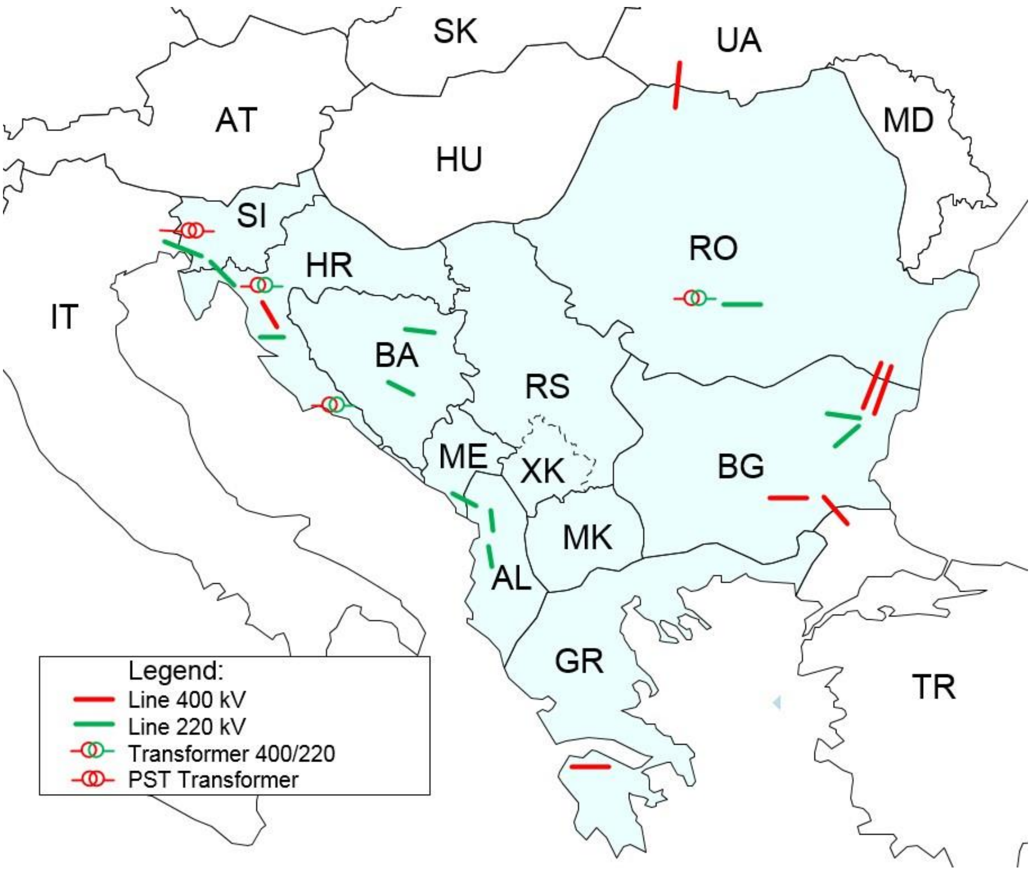


Figure 207: Geographical distribution of the critical transmission network elements in the region in all analyzed scenarios

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

[5] It seems than submitted input data on TS 400/220 kV Meline (HR) capacity is incorrect, so this should be double-checked.

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 total number of contingencies in all scenarios per each country. It assumes number of elements whose outage is causing overloadings in the network. For each scenario two bars are given. Bar A represents contingencies on internal lines, while bar B represents interconnetion lines. In each bar number of contingencies per each country is separately labeled. **The highest number of outages in one scenario is 8 and it is found in scenario 5. Clearly, there is no scenario with extremely high number of contingencies which is good sign of network robustness.**

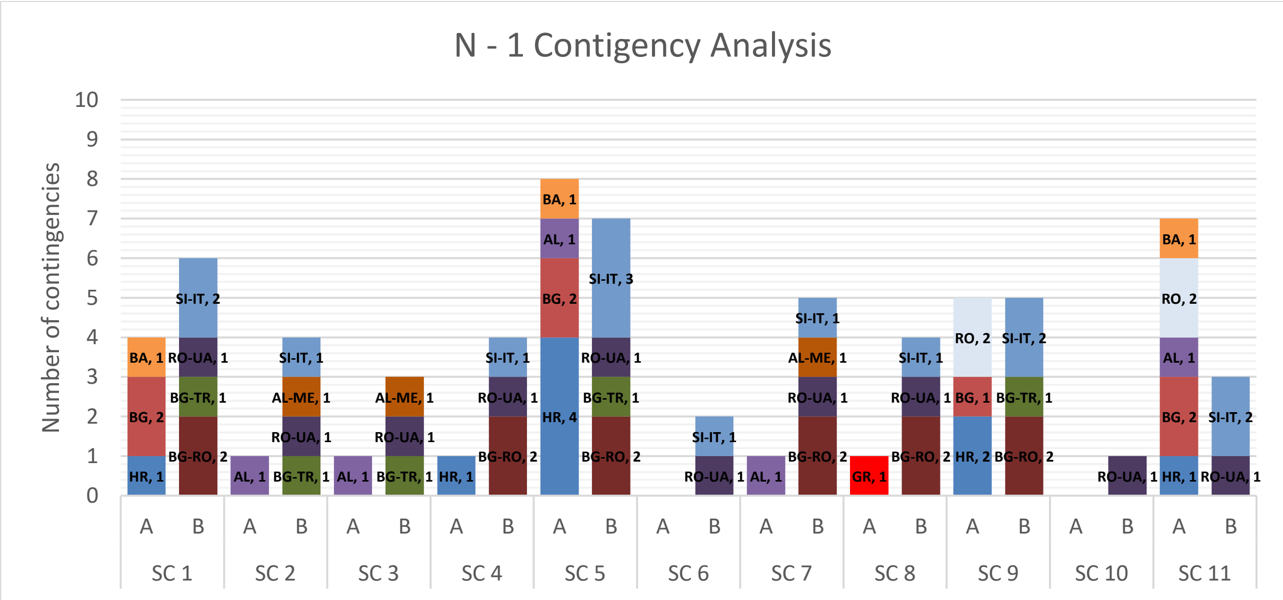


Figure 208: Total number of contingencies in all scenarios with each country contribution

Network models are based on official TSOs' 10-year network development plans. This analysis assumed significant changes till 2030 in all power systems, including additional 25% of RES capacities on top of RES capacities already included in official 10-year network development plans. **Total installed capacities will increase for 30% or for more than 24000 MW.** Therefore, **with only 22 bottlenecks that are found in the region in all 11 scenarios, we can conclude that regional network is quite robust for future absorption of additional RES capacities.**

Similar to contingency comparison, the following figure shows comparison of the network losses per each scenario. Total network losses in the region are in the range of 500 – 1400 MW. As expected, each country share is changing depending on the scenario.

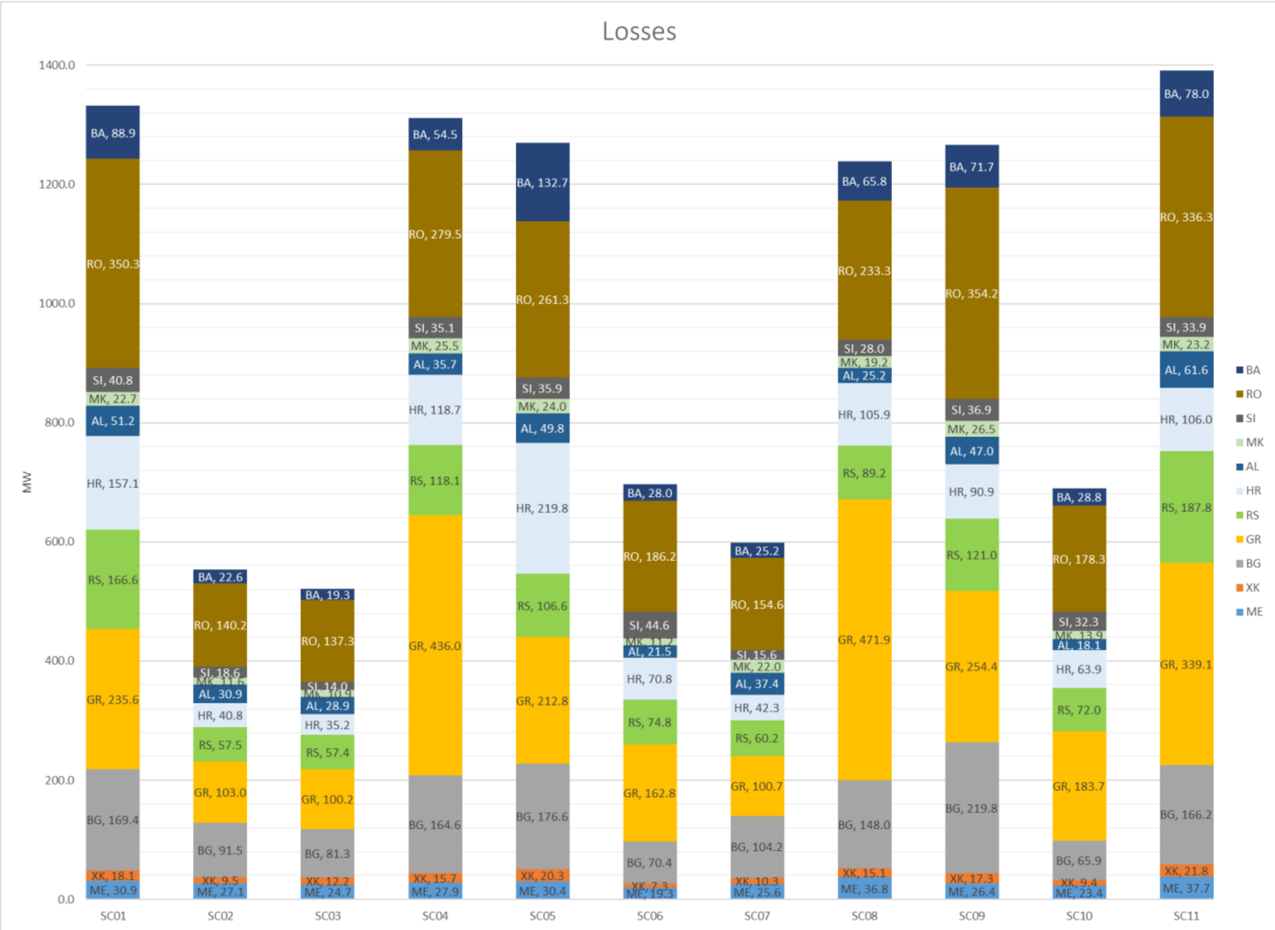


Figure 209: Total regional transmission network losses in all scenarios with each country contribution

Knowing that the EMI members are focused in RES integration impact on their internal network operation, network losses and voltage profiles overviews are compared between scenarios in the following subchapters for each TSO area separately.

Two figures on losses show transmission network losses in each area in all 11 analyzed scenarios. The first two scenarios are base cases with minimum and maximum system load. All other scenarios are with high RES penetration. Even though for more detailed loss analysis we would need yearly timeframe, on these indicative figures we can follow the impact of RES integration on the level of losses in each country and its percentage to the total system load. We have to keep in mind that the network losses strongly depend on the geographical dispersion of RES sites as well as its daily and seasonal curves.

The other two figures give overview of the voltage profiles in each area in all 11 analyzed cases.

6.12.1. OST (AL) network area

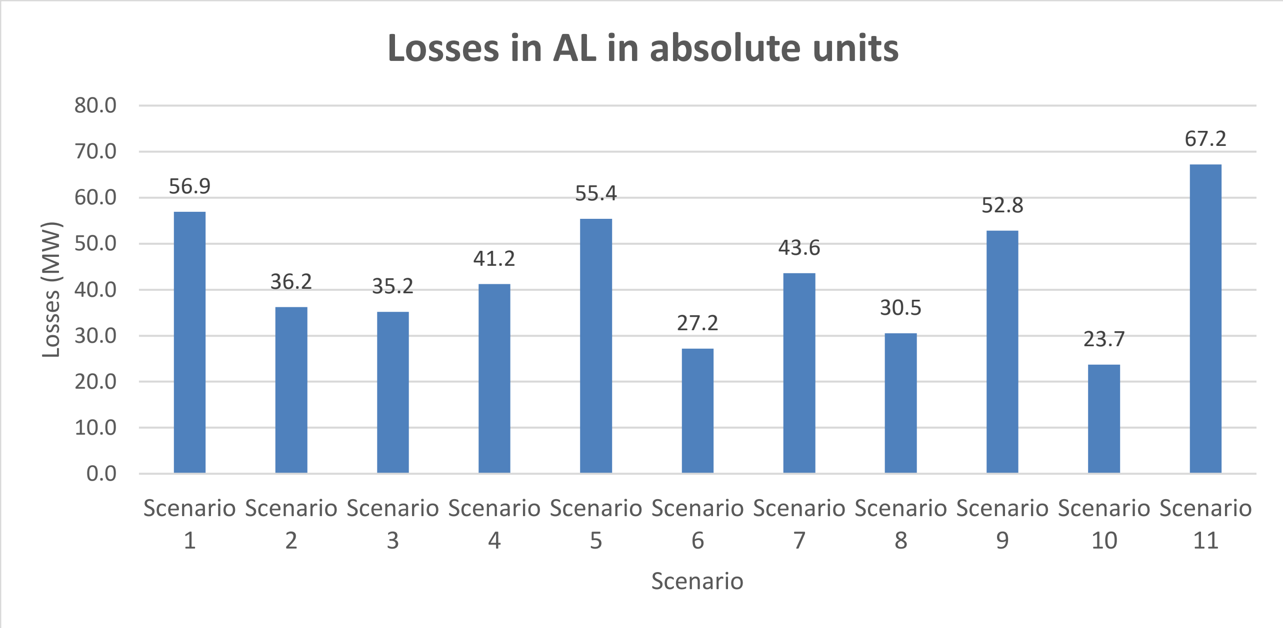


Figure 210: Transmission network losses in absolute value in AL area in all analyzed scenarios

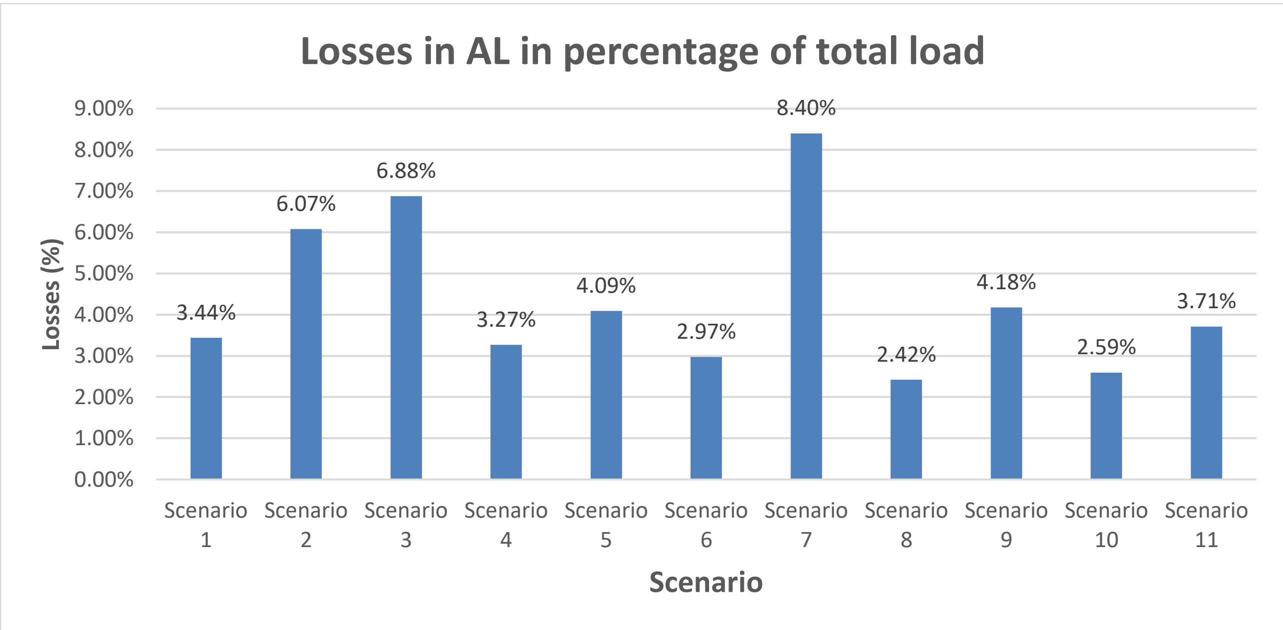


Figure 211: Transmission network losses in AL area relative to system load in all analyzed scenarios

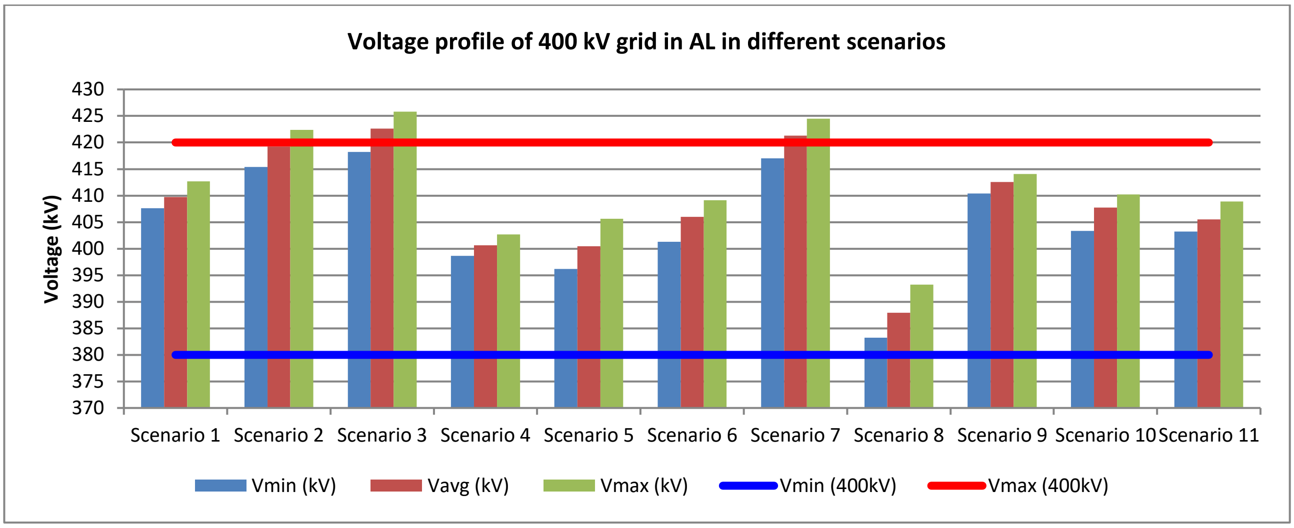


Figure 212: 400 kV voltage profiles (minimum, maximum and average) in AL area in all analyzed scenarios

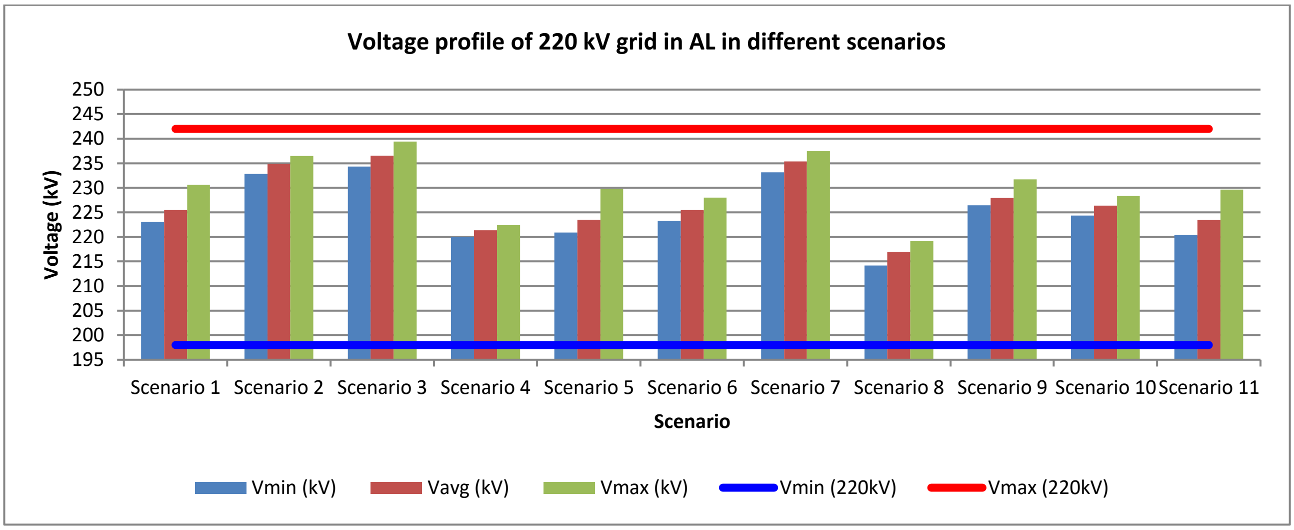


Figure 213: 220 kV voltage profiles (minimum, maximum and average) in AL area in all analyzed scenarios

6.12.2. NOS BiH (BA) network area

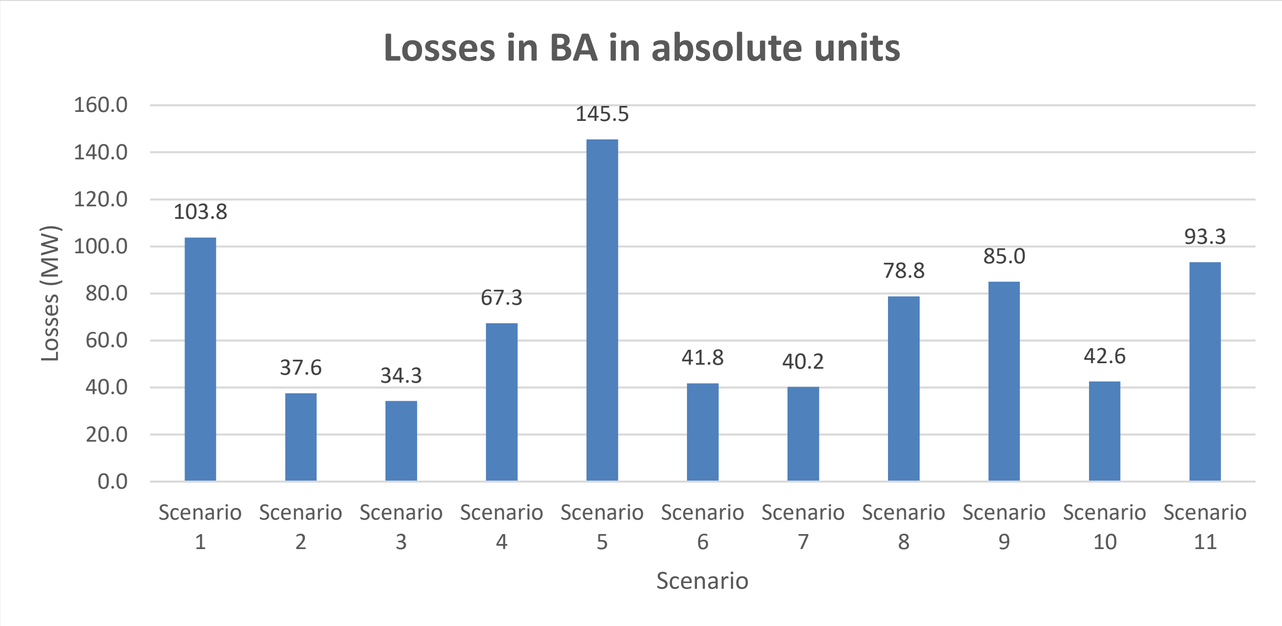


Figure 214: Transmission network losses in absolute value in BiH area in all analyzed scenarios

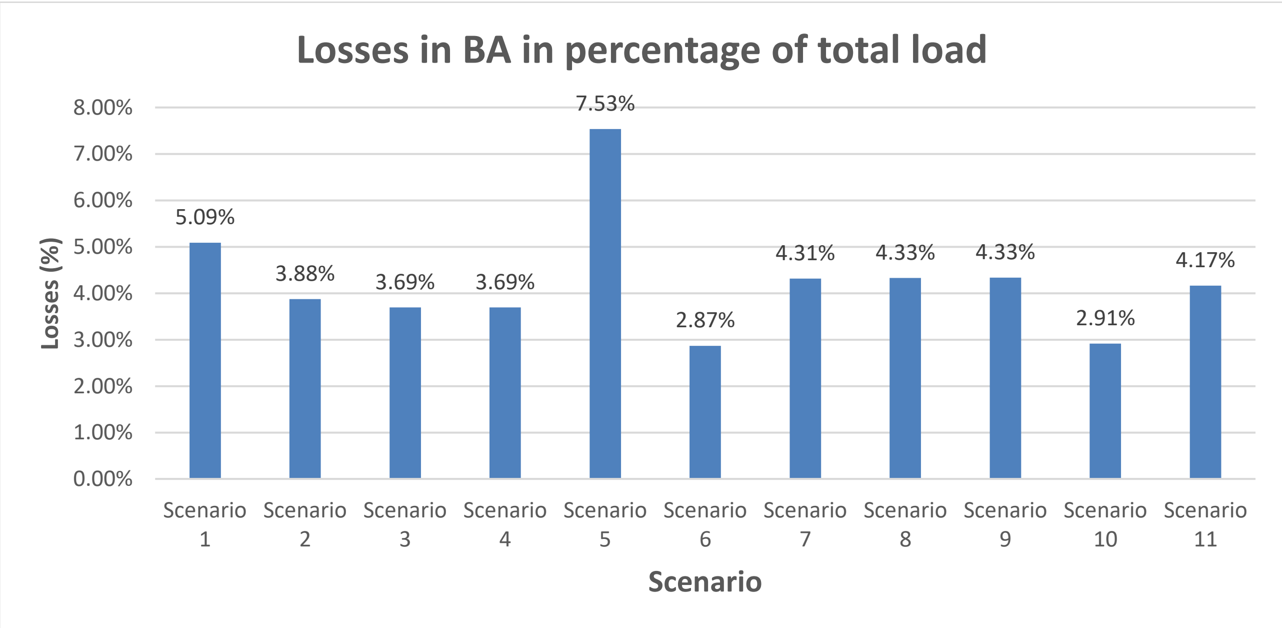


Figure 215: Transmission network losses in BiH area relative to system load in all analyzed scenarios

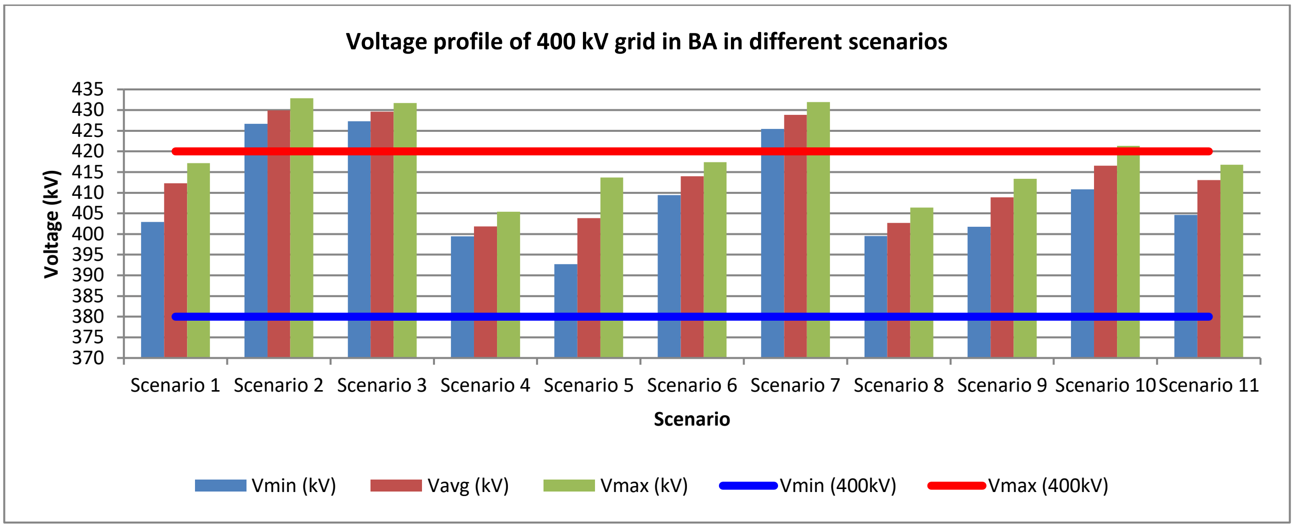


Figure 216: 400 kV voltage profiles (minimum, maximum and average) in BiH area in all analyzed scenarios

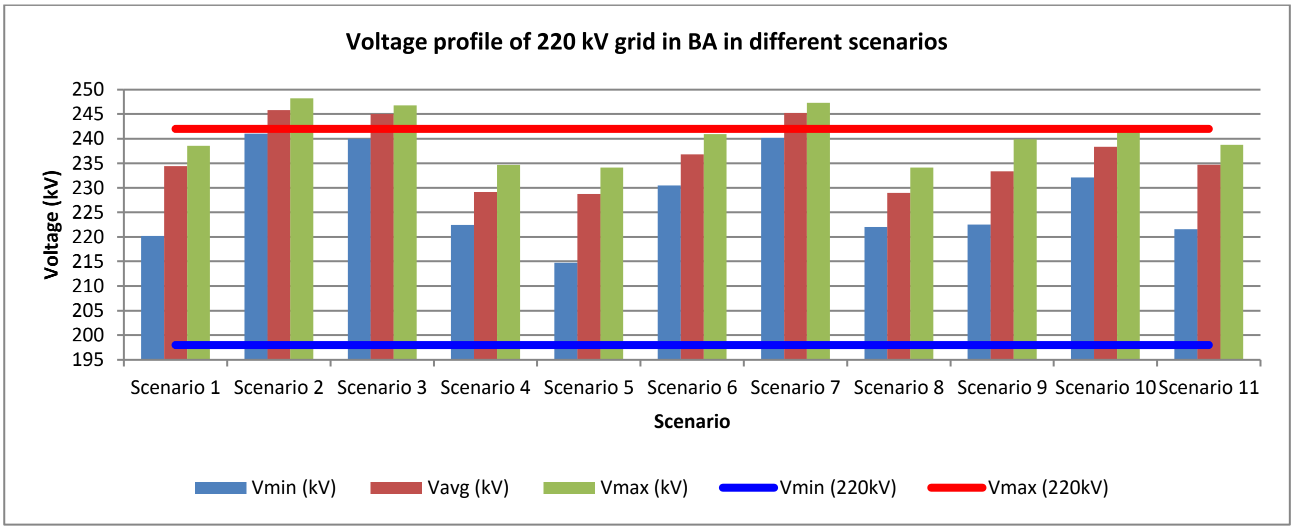


Figure 217: 220 kV voltage profiles (minimum, maximum and average) in BiH area in all analyzed scenarios

6.12.3. ESO (BG) network area

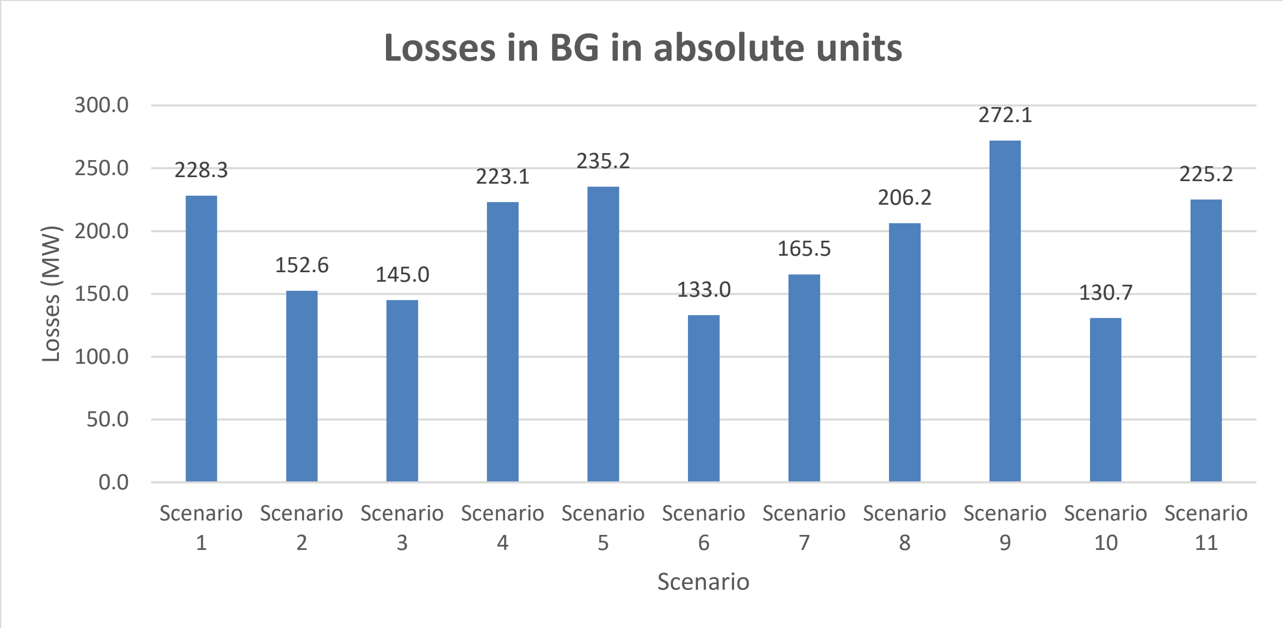


Figure 218: Transmission network losses in absolute value in BG area in all analyzed scenarios

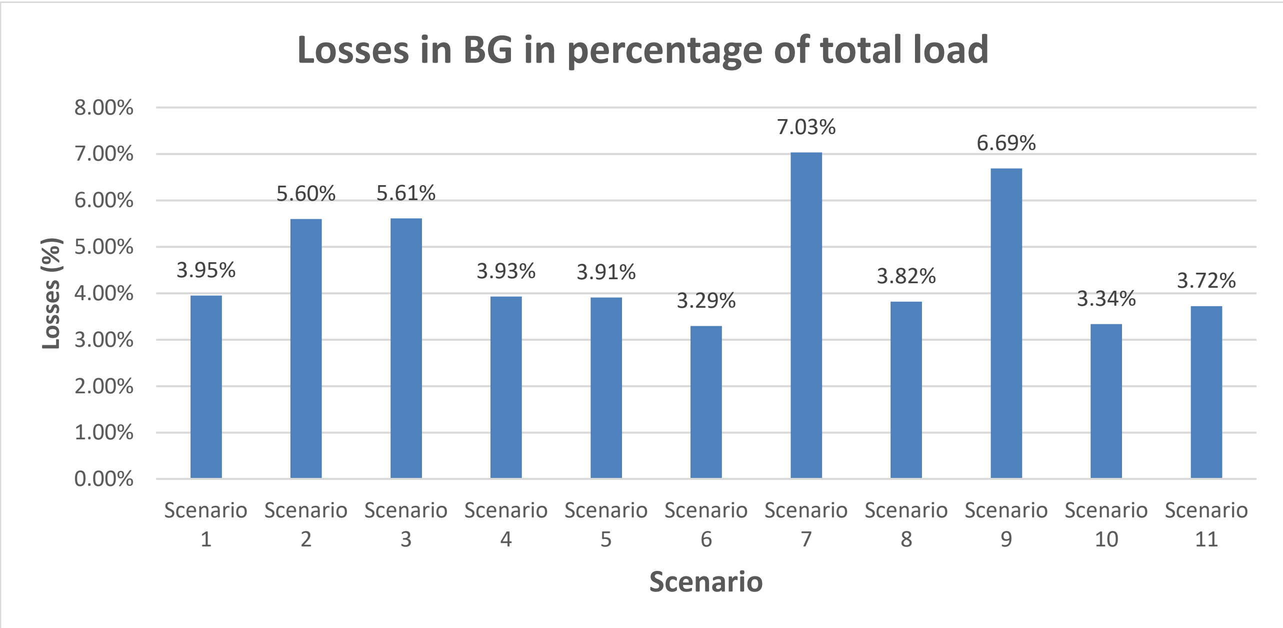


Figure 219: Transmission network losses in BG area relative to system load in all analyzed scenarios

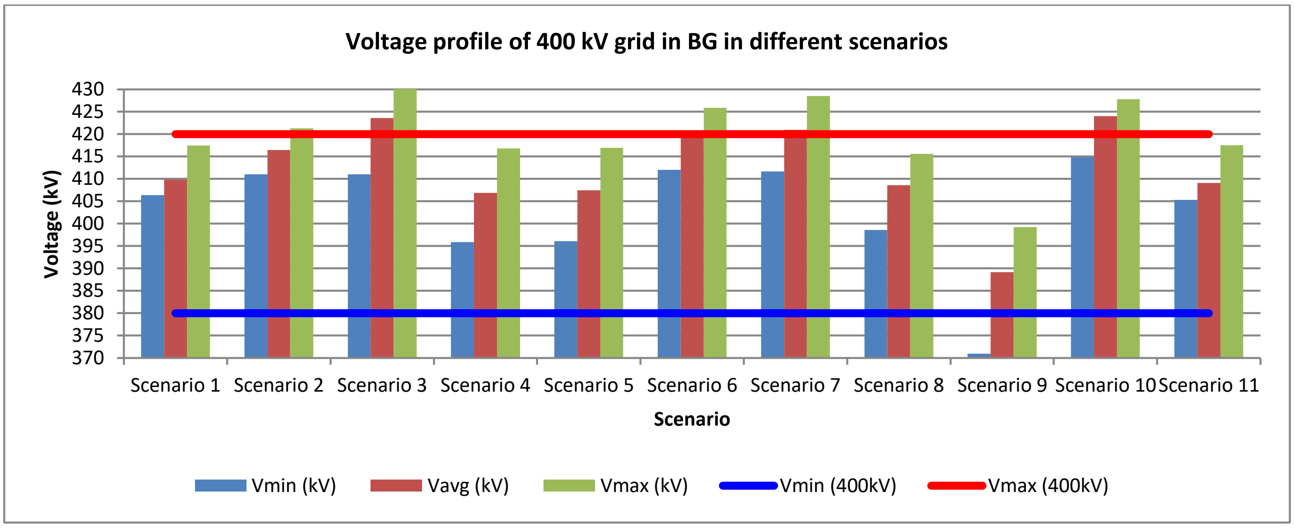


Figure 220: 400 kV voltage profiles (minimum, maximum and average) in Bulgaria in all analyzed scenarios

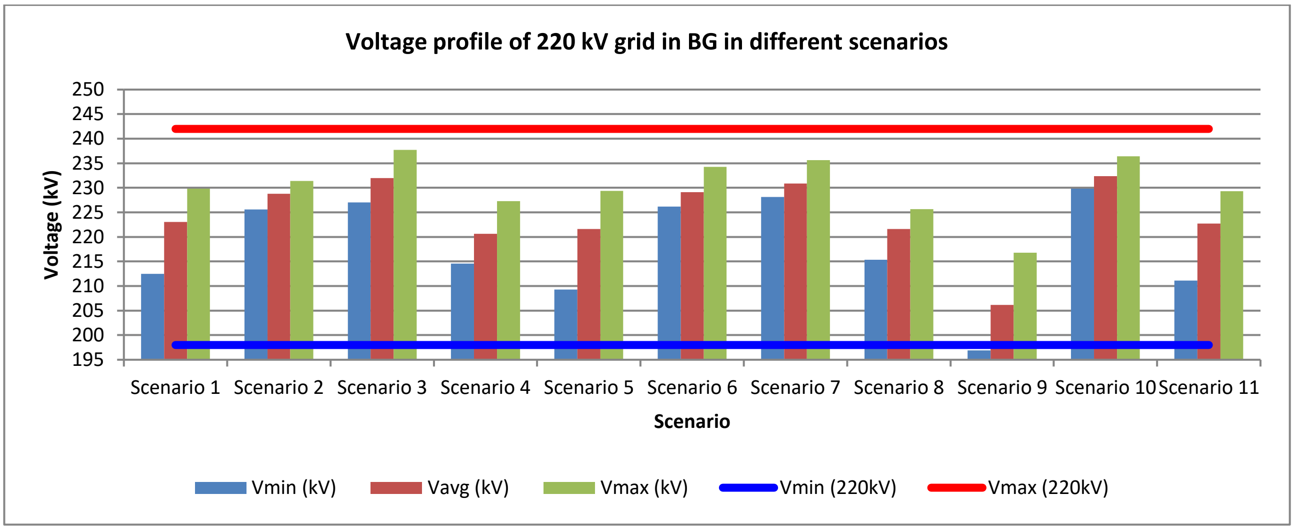


Figure 221: 220 kV voltage profiles (minimum, maximum and average) in Bulgaria in all analyzed scenarios

6.12.4. IPTO (GR) network area

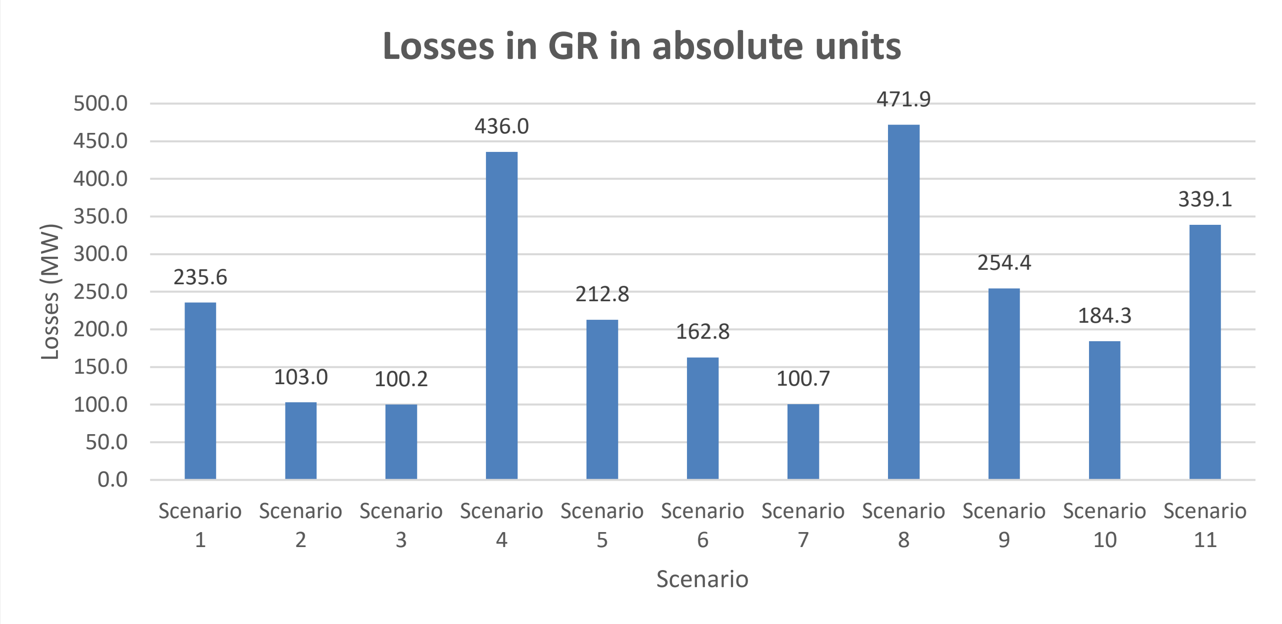


Figure 222: Transmission network losses in absolute value in GR area in all analyzed scenarios

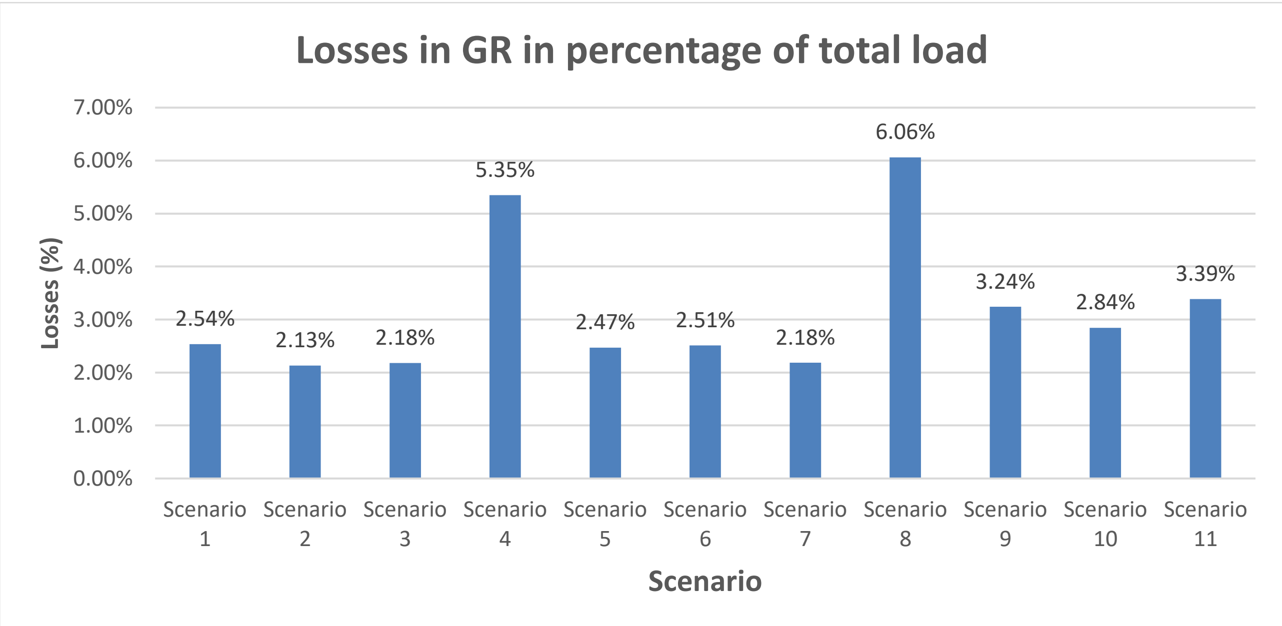


Figure 223: Transmission network losses in GR area relative to system load in all analyzed scenarios

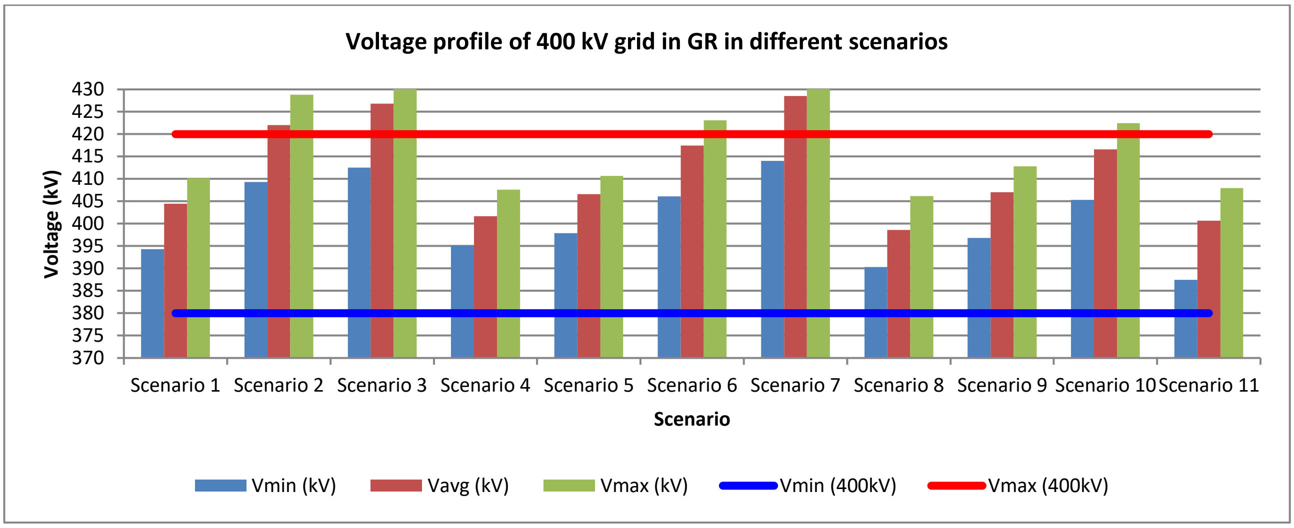


Figure 224: 400 kV voltage profiles (minimum, maximum and average) in GR area in all analyzed scenarios

6.12.5. HOPS (HR) network area

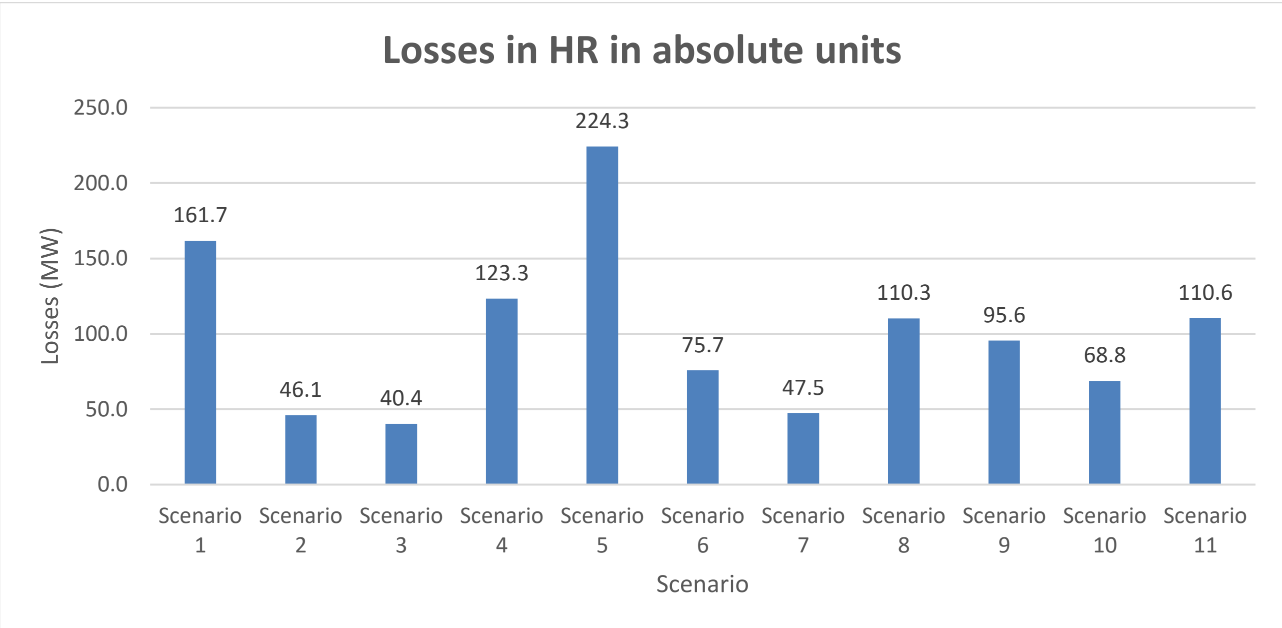


Figure 225: Transmission network losses in absolute value in Croatia in all analyzed scenarios

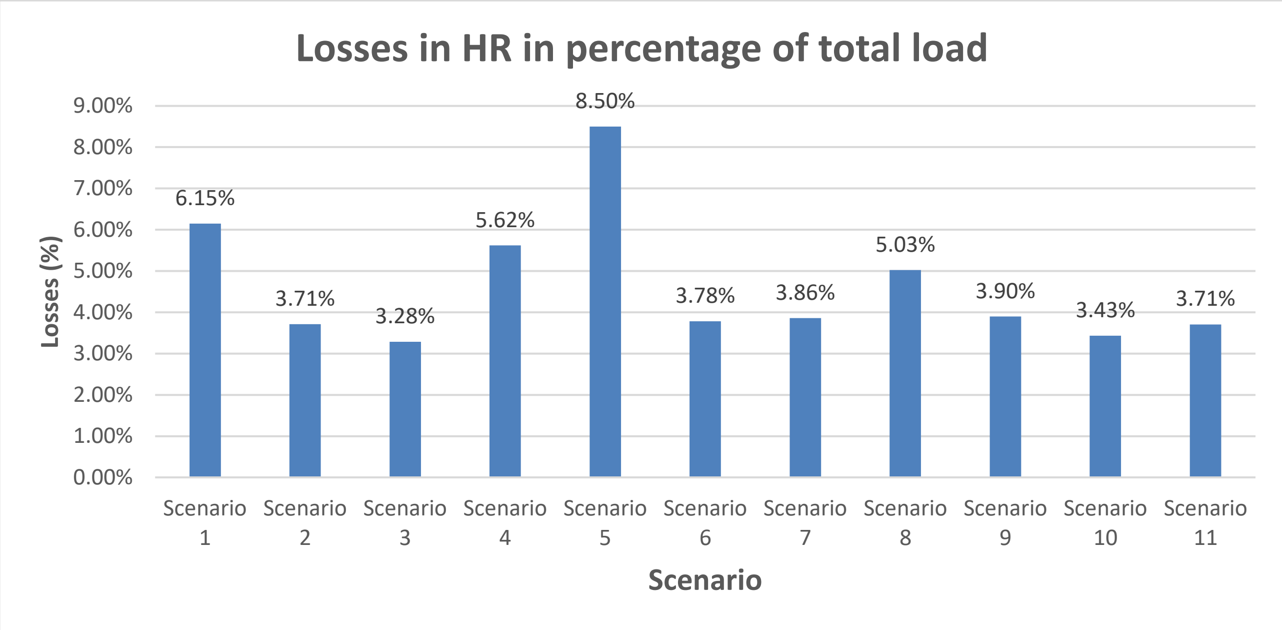


Figure 226: Transmission network losses in Croatia relative to system load in all analyzed scenarios

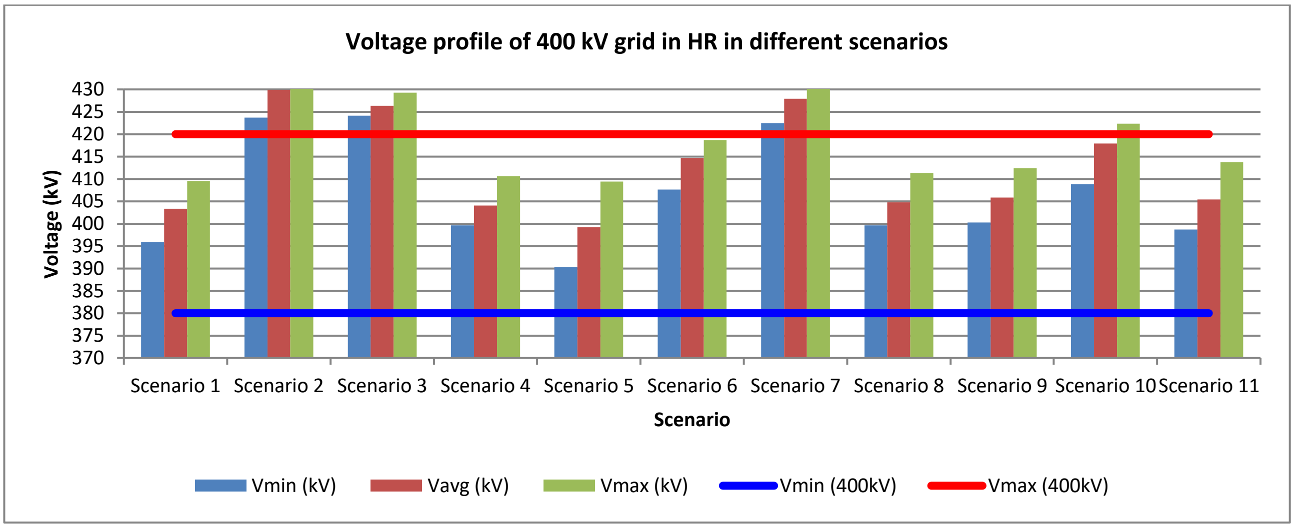


Figure 227: 400 kV voltage profiles (minimum, maximum and average) in Croatia in all analyzed scenarios

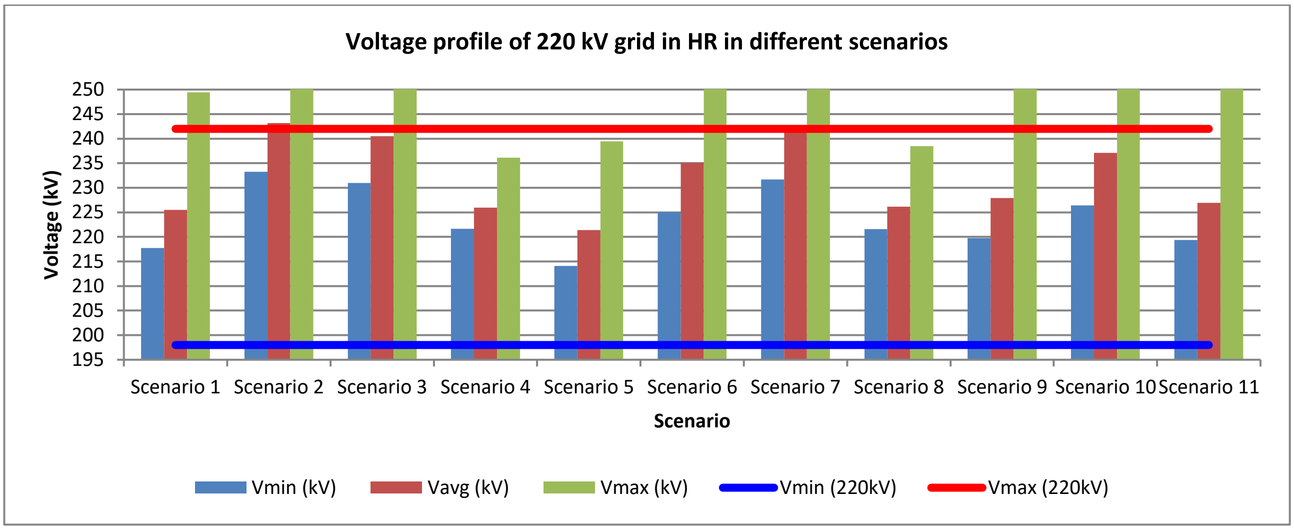


Figure 228: 220 kV voltage profiles (minimum, maximum and average) in Croatia in all analyzed scenarios

6.12.6. CGES (ME) network area

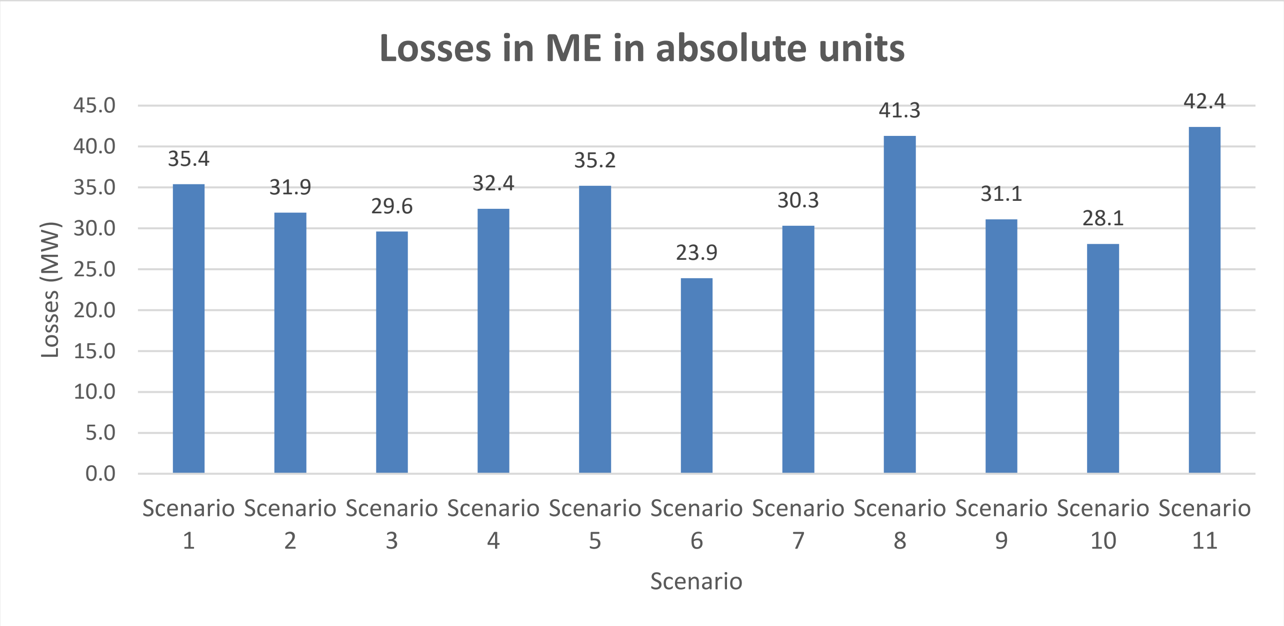


Figure 229: Transmission network losses in absolute value in ME area in all analyzed scenarios

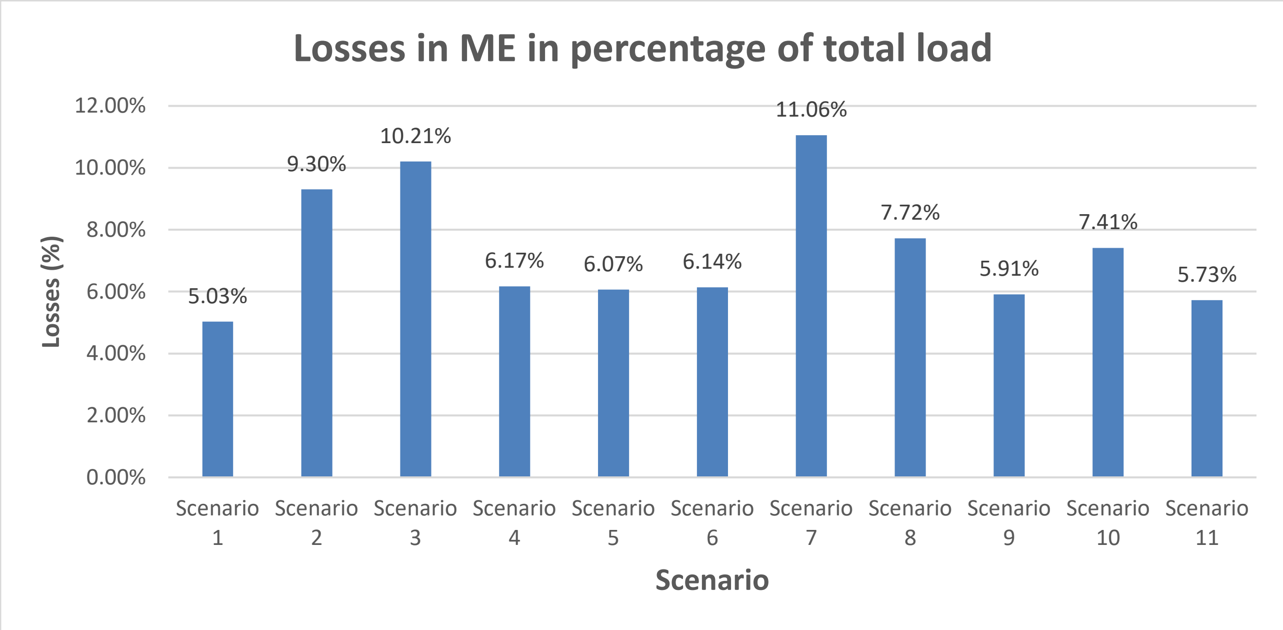


Figure 230: Transmission network losses in ME area relative to system load in all analyzed scenarios

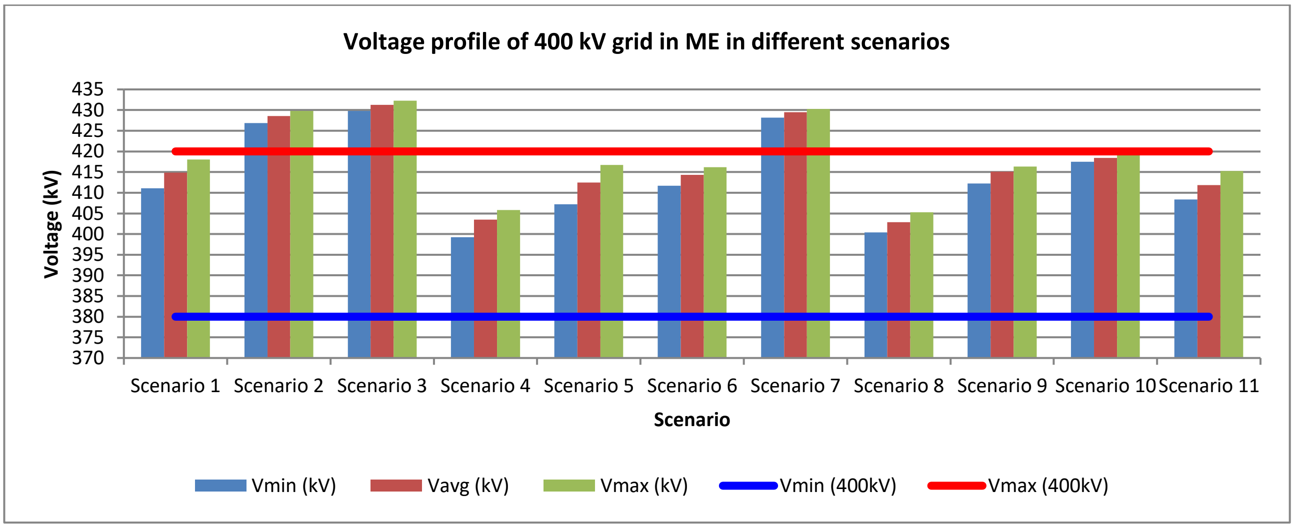


Figure 231: 400 kV voltage profiles (minimum, maximum and average) in ME area in all analyzed scenarios

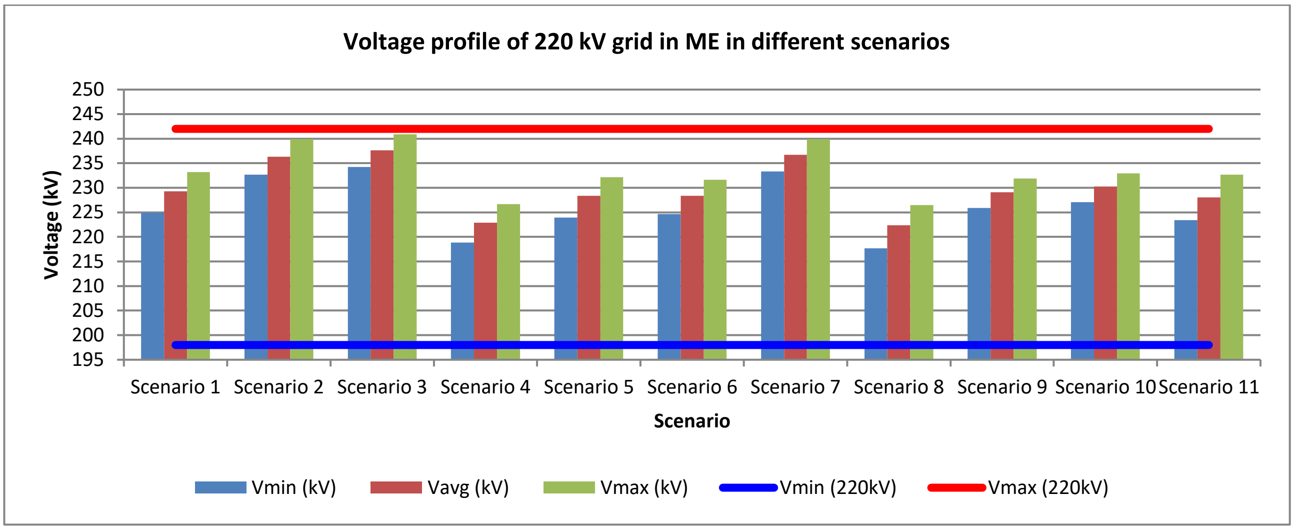


Figure 232: 220 kV voltage profiles (minimum, maximum and average) in ME area in all analyzed scenarios

6.12.7. MEPSO (MK) network area

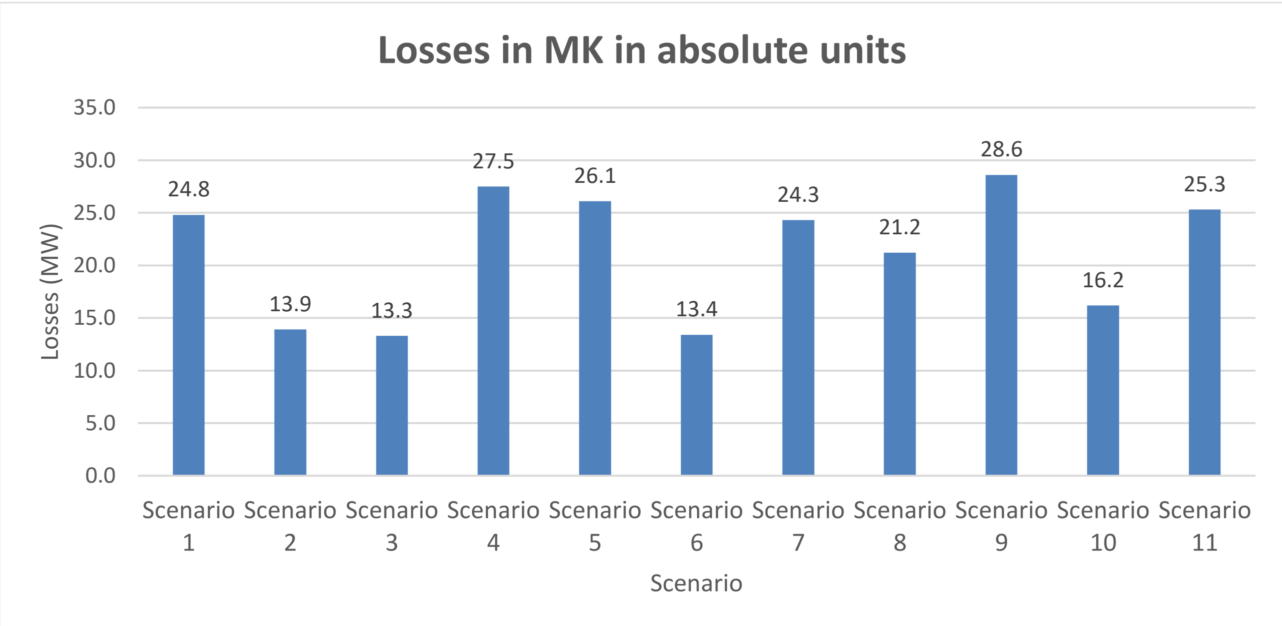


Figure 233: Transmission network losses in absolute value in N.Macedonia in all analyzed scenarios

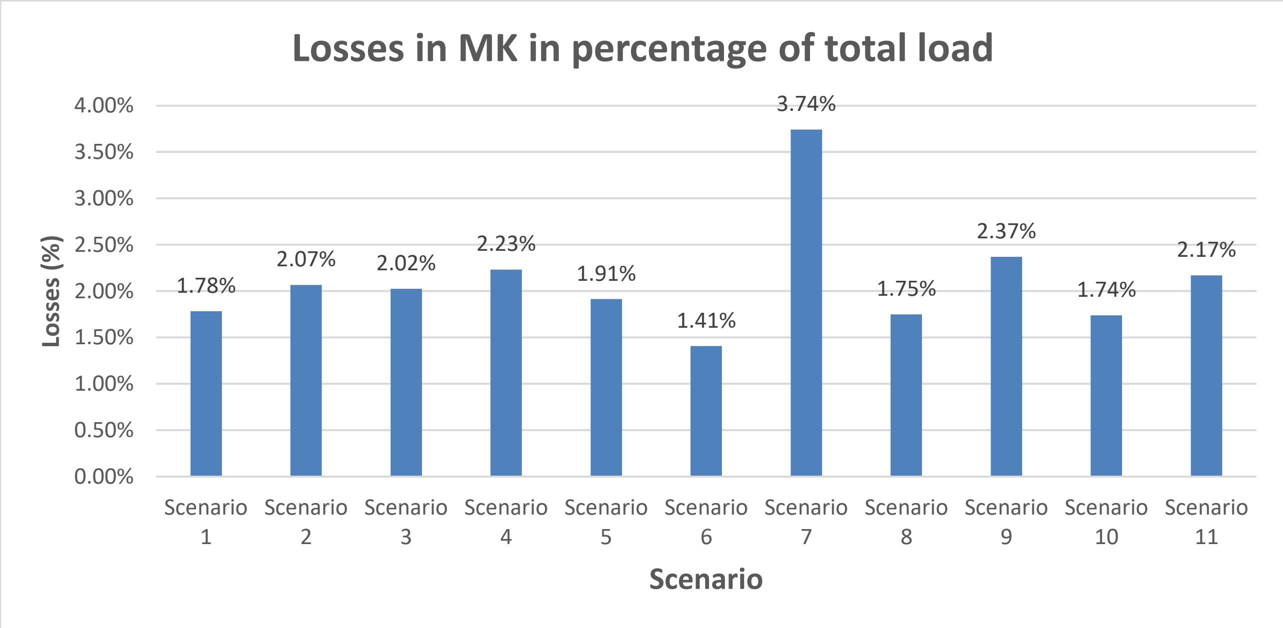


Figure 234: Transmission network losses in N.Macedonia relative to system load in all analyzed scenarios

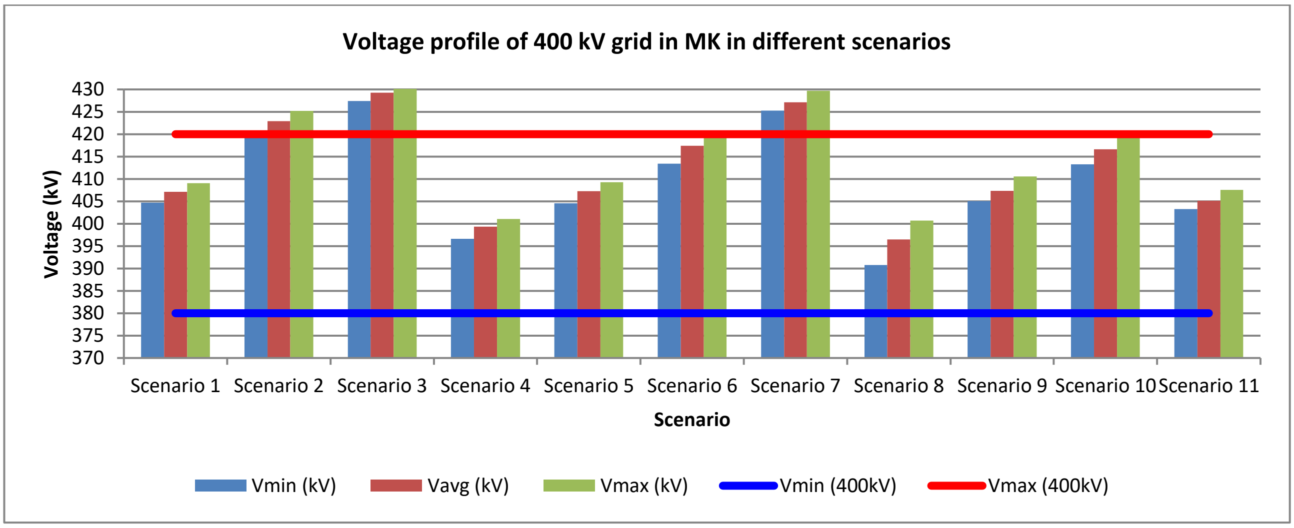


Figure 235: 400 kV voltage profiles (minimum, maximum and average) in MK area in all analyzed scenarios

6.12.8. Transelectrica (RO) network area

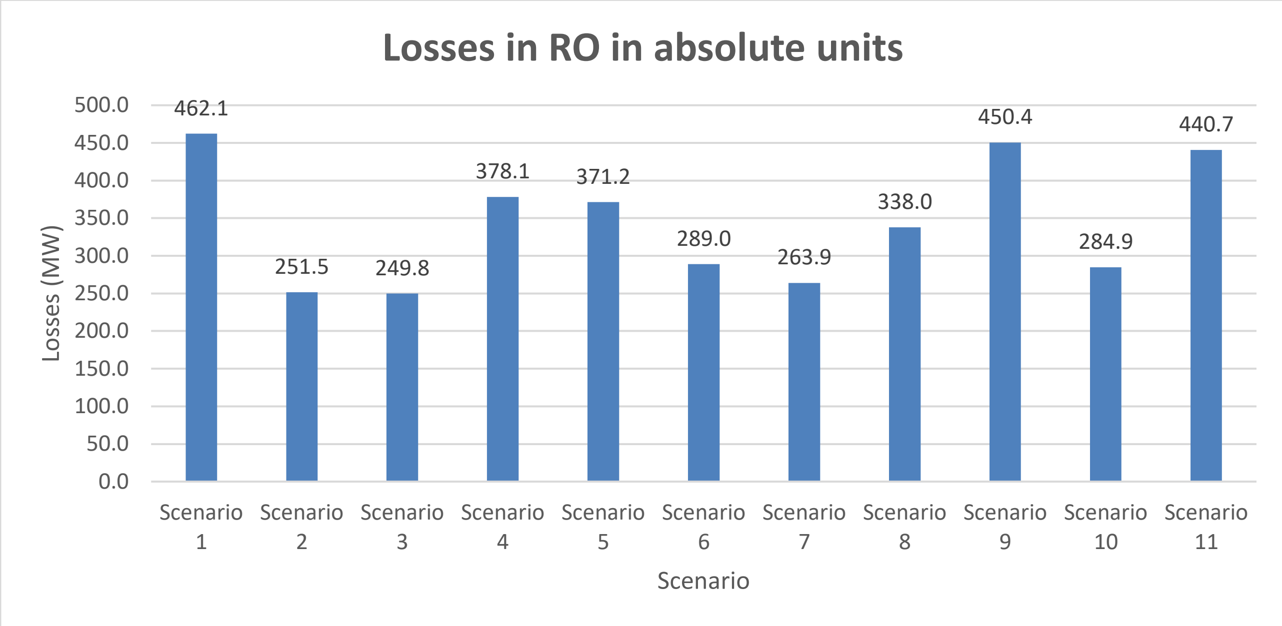


Figure 236: Transmission network losses in absolute value in Romania in all analyzed scenarios

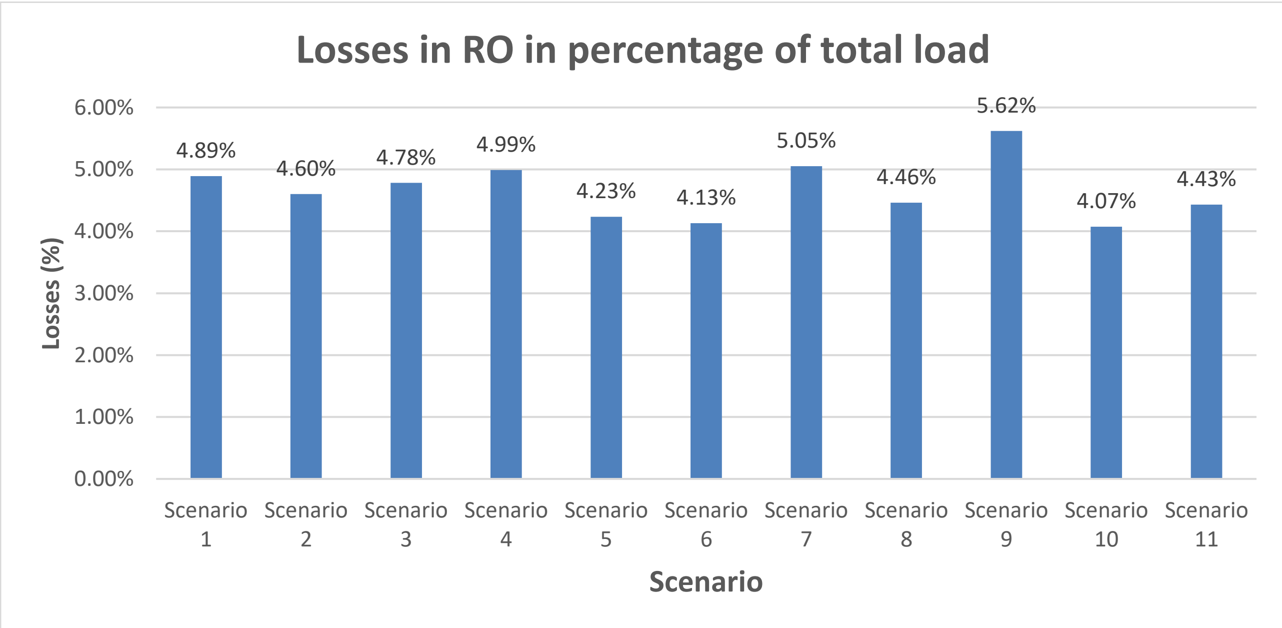


Figure 237: Transmission network losses in Romania relative to system load in all analyzed scenarios

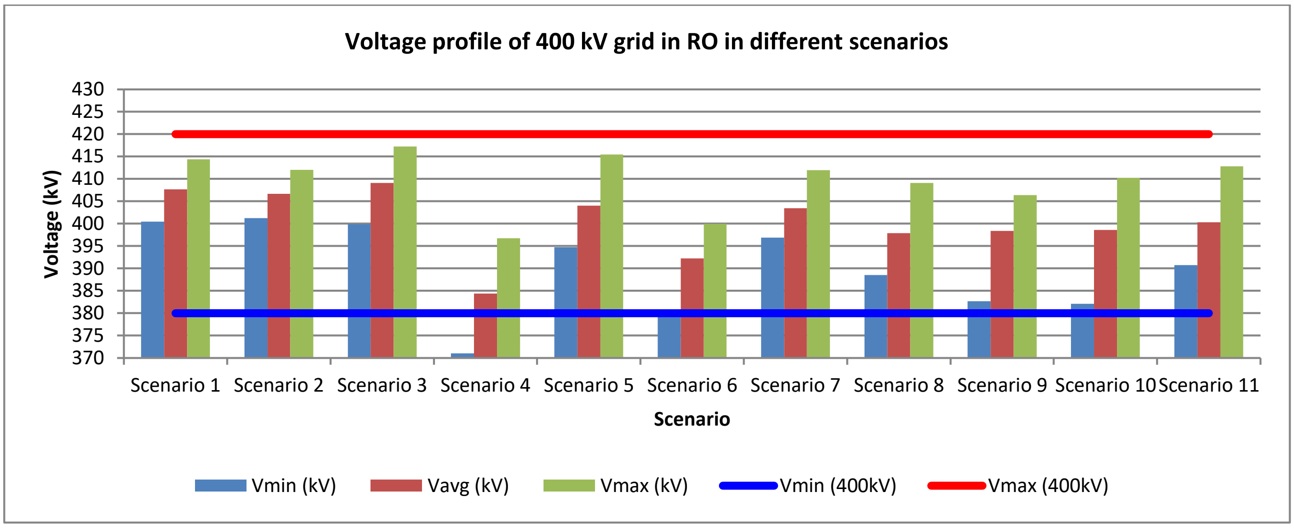


Figure 238: 400 kV voltage profiles (minimum, maximum and average) in Romania in all analyzed scenarios

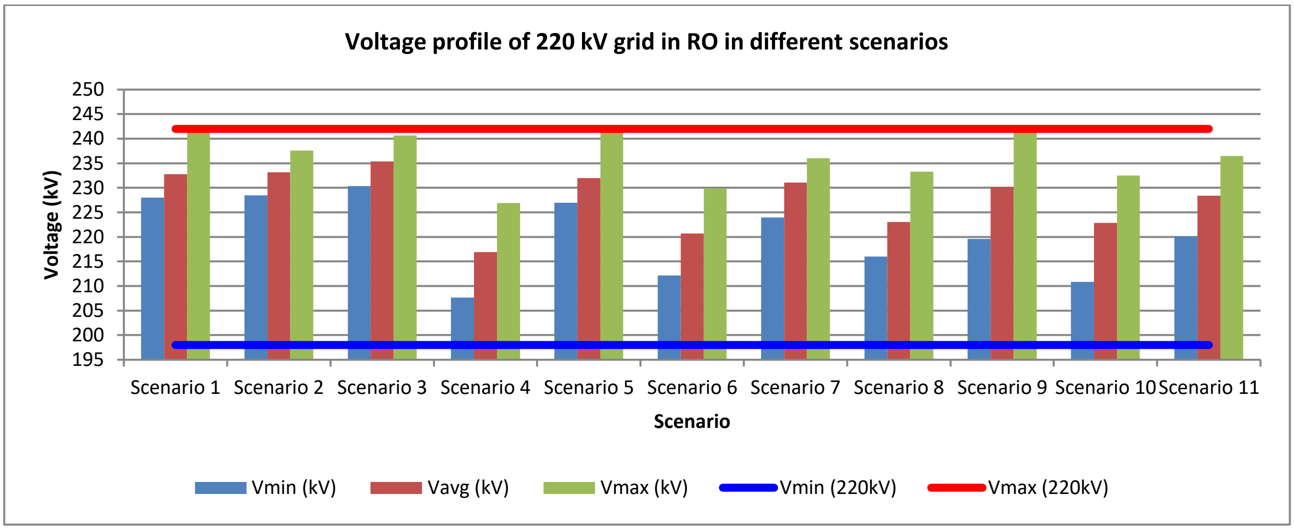


Figure 239: 220 kV voltage profiles (minimum, maximum and average) in Romania in all analyzed scenarios

6.12.9. EMS (RS) network area

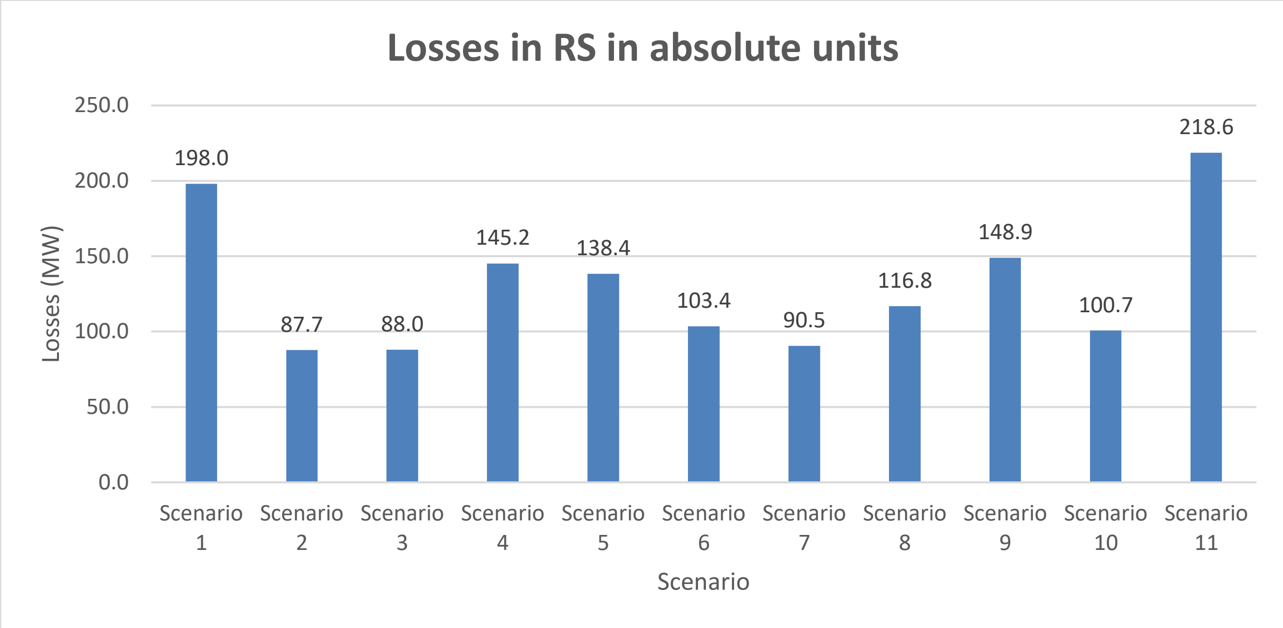


Figure 240: Transmission network losses in absolute value in RS area in all analyzed scenarios

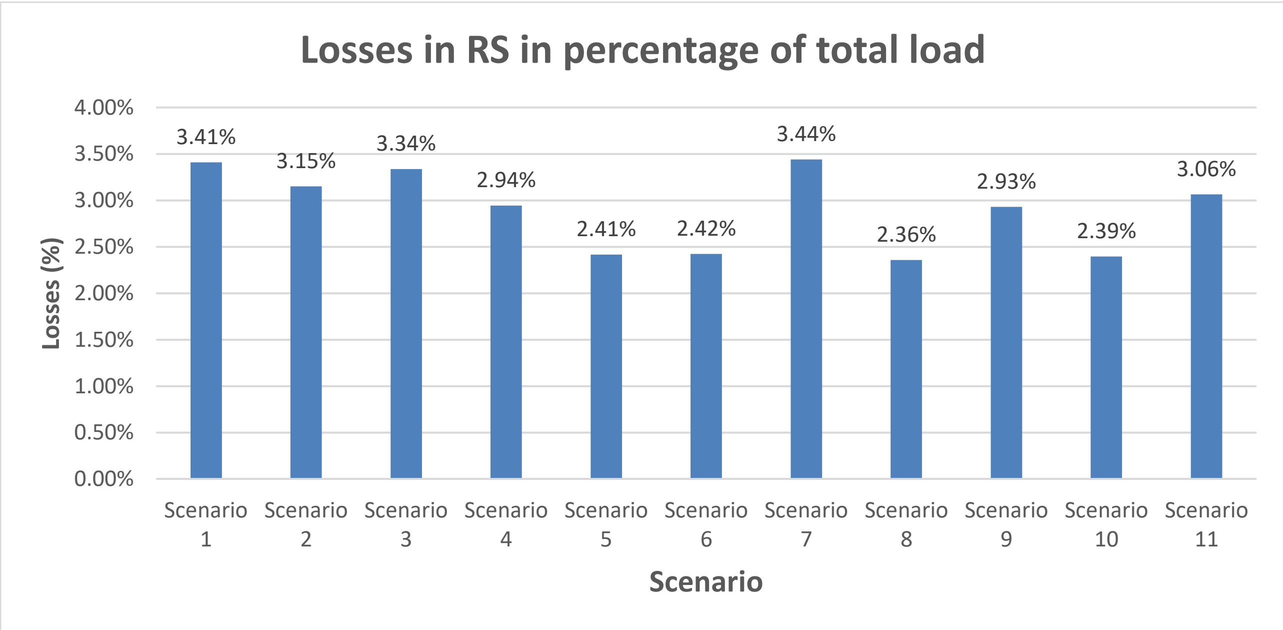


Figure 241: Transmission network losses in RS area relative to system load in all analyzed scenarios

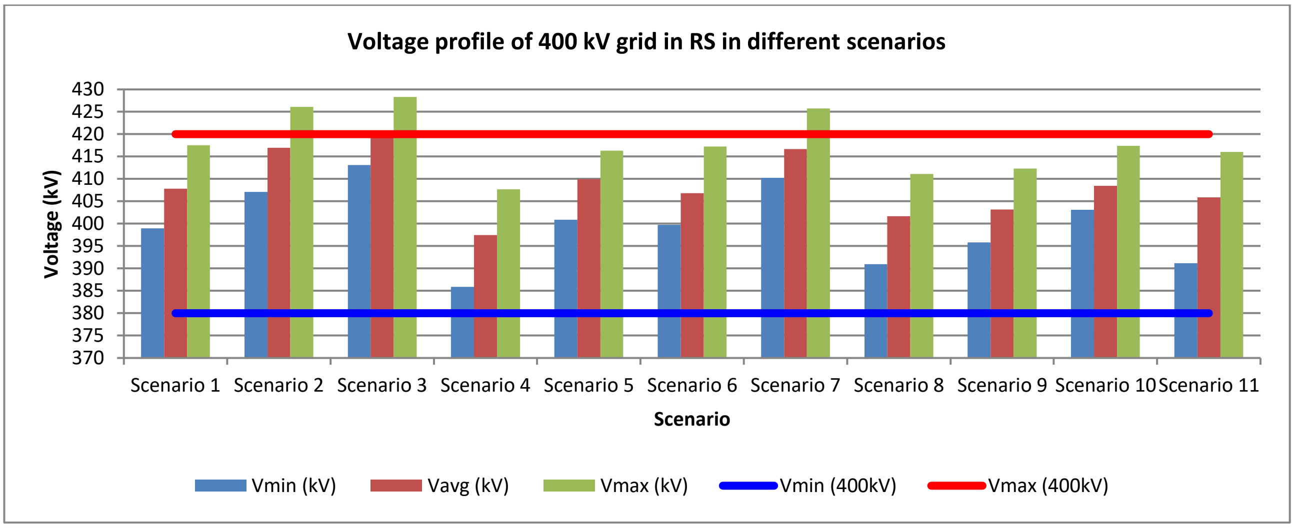


Figure 242: 400 kV voltage profiles (minimum, maximum and average) in RS area in all analyzed scenarios

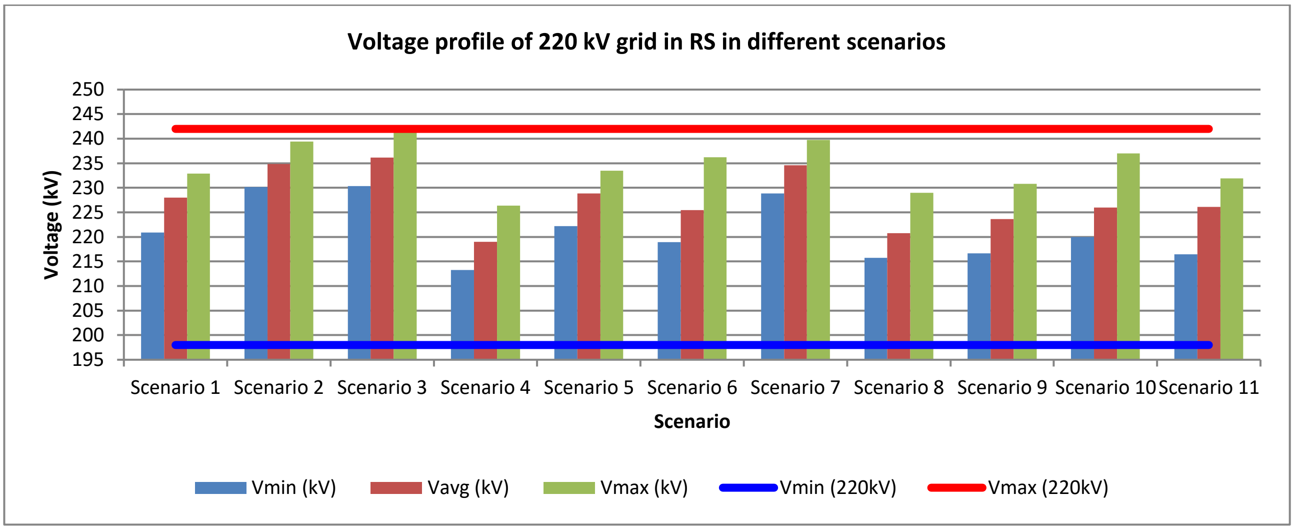


Figure 243: 220 kV voltage profiles (minimum, maximum and average) in RS area in all analyzed scenarios

6.12.10. ELES (SI) network area

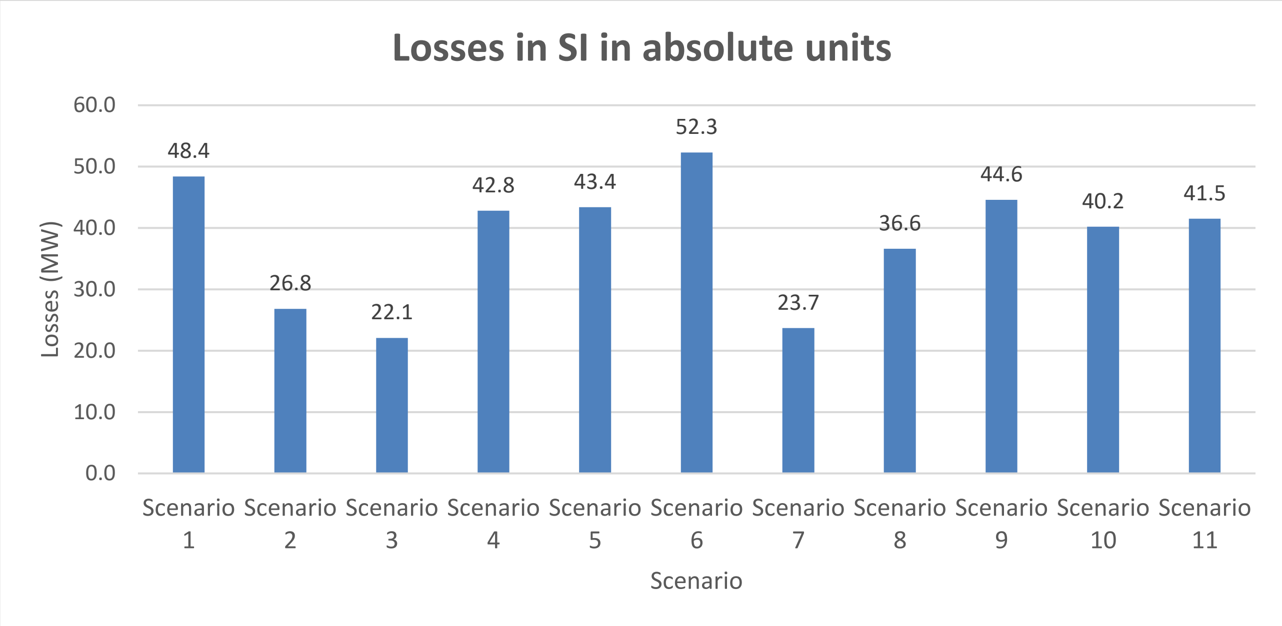


Figure 244: Transmission network losses in absolute value in Slovenia in all analyzed scenarios

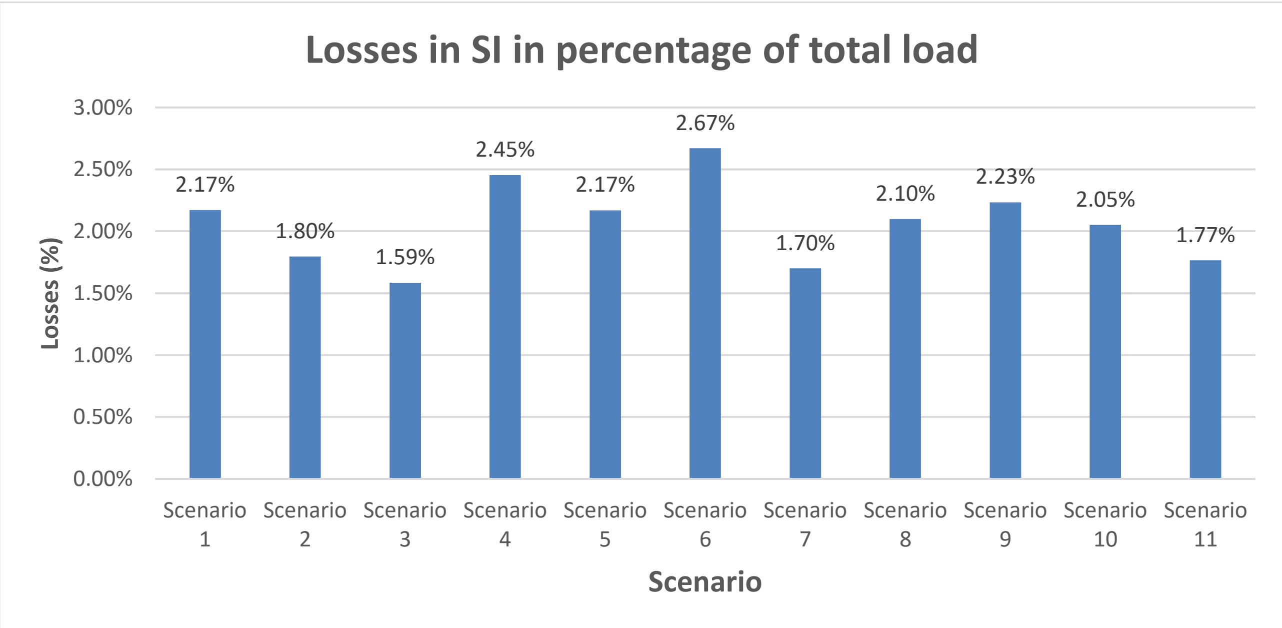


Figure 245: Transmission network losses in Slovenia relative to system load in all analyzed scenarios

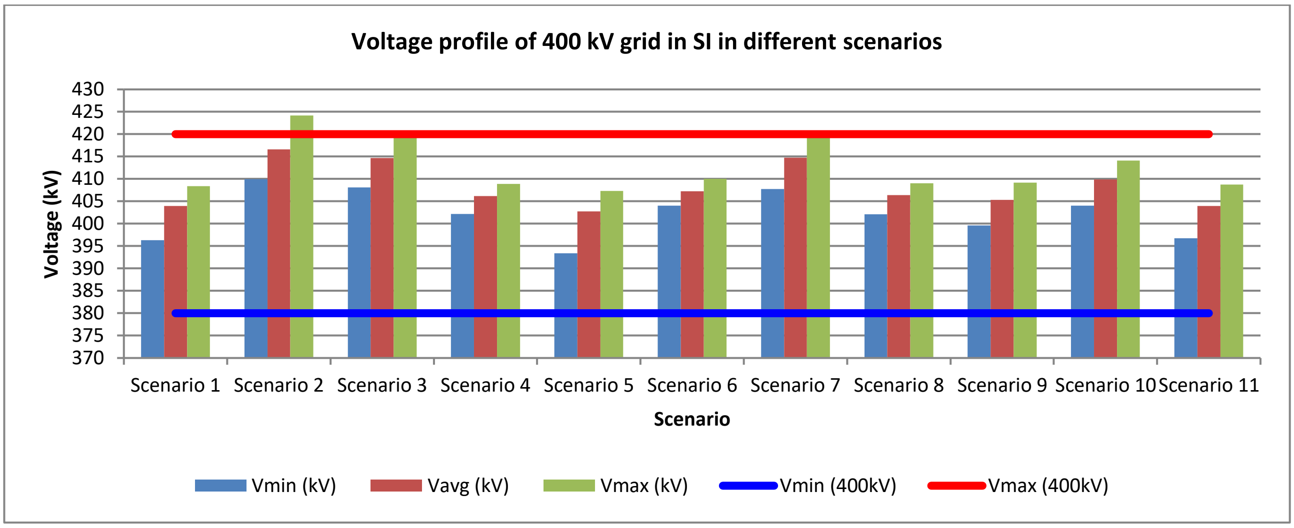


Figure 246: 400 kV voltage profiles (minimum, maximum and average) in Slovenia in all analyzed scenarios

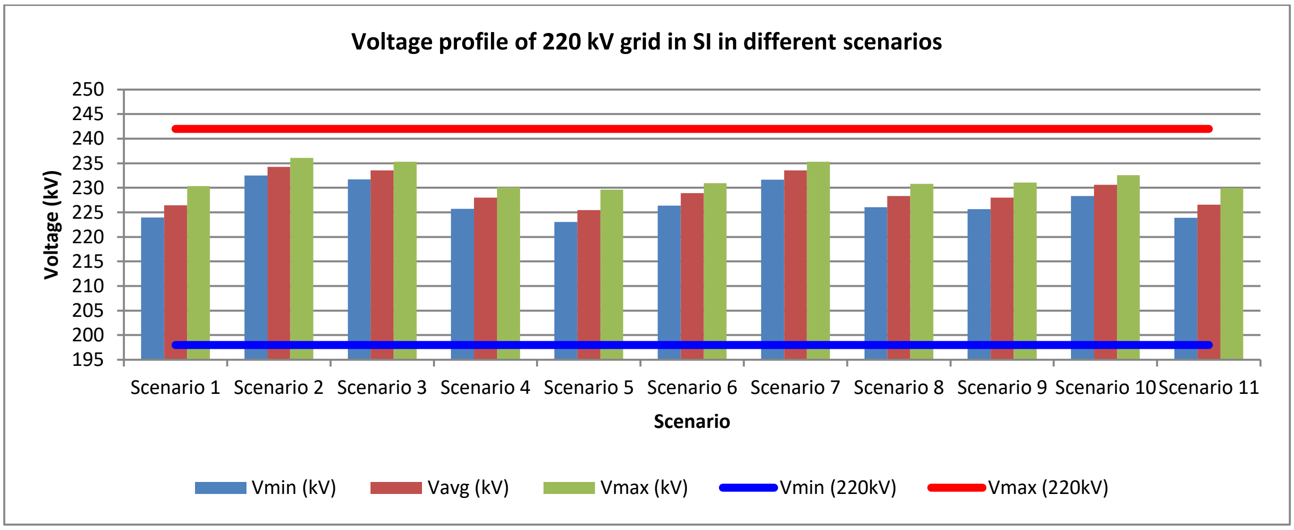


Figure 247: 220 kV voltage profiles (minimum, maximum and average) in Slovenia in all analyzed scenarios

6.12.11. KOSTT (XK) network area

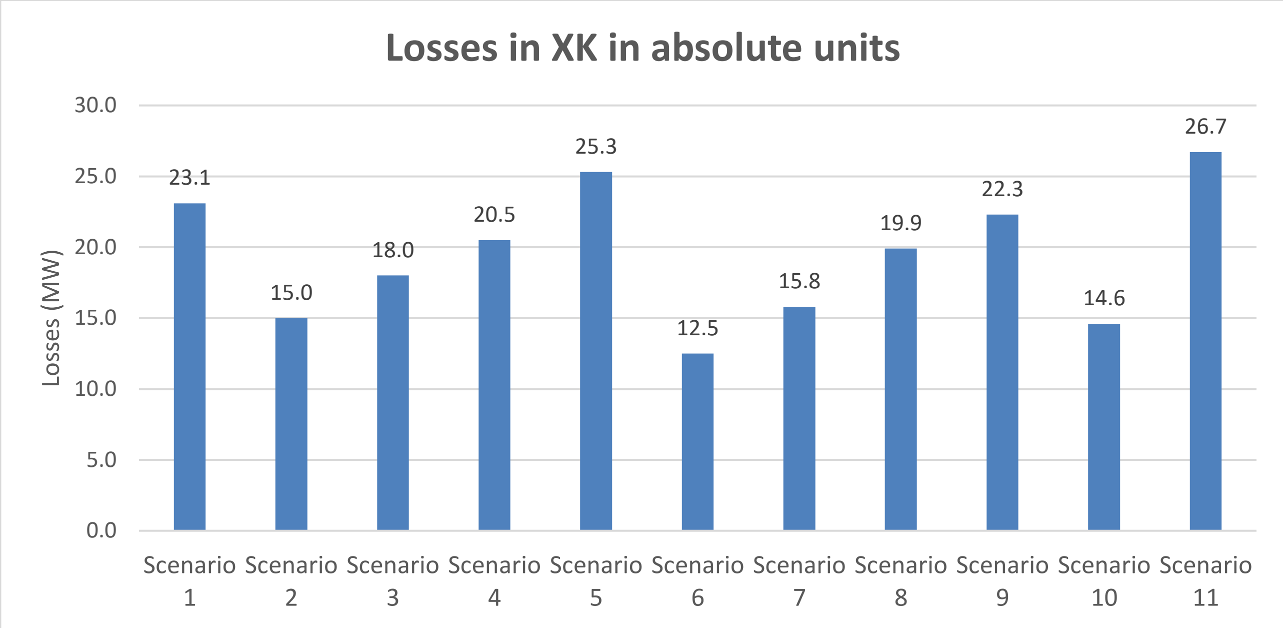


Figure 248: Transmission network losses in absolute value in XK area in all analyzed scenarios

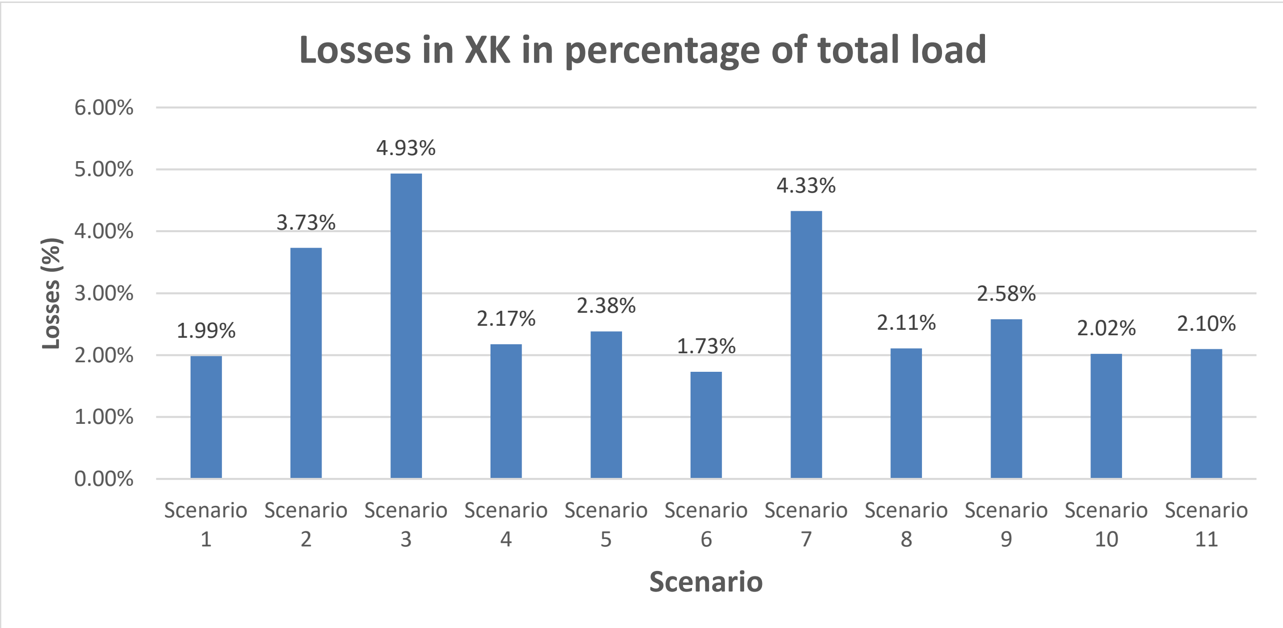


Figure 249: Transmission network losses in XK area relative to system load in all analyzed scenarios

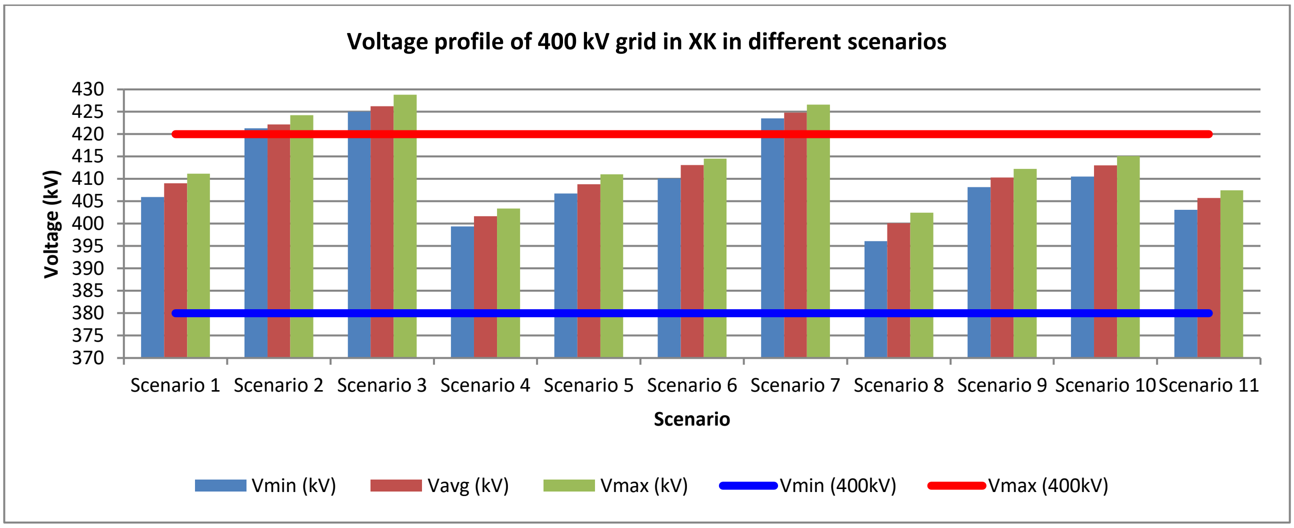


Figure 250: 400 kV voltage profiles (minimum, maximum and average) in XK area in all analyzed scenarios

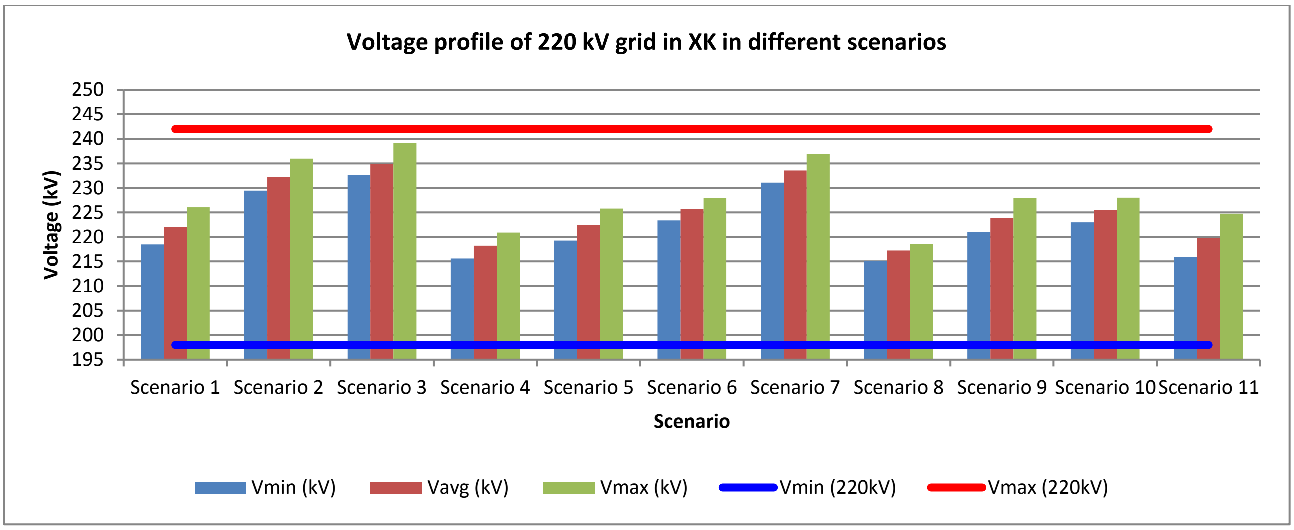


Figure 251: 220 kV voltage profiles (minimum, maximum and average) in XK area in all analyzed scenarios

7. CONCLUSIONS

The newly adopted EU Energy Law (the "Clean Energy for all Europeans") package has set 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, 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.

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 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 Draft Report consists of 8 chapters on 344 pages, including 297 figures and 197 tables. It provides detailed overview of 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 South East European power system foreseen in 2030 with different levels of RES integration.

Based on all input data submitted by the TSOs we expect **total regional demand growth in the period of 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 is in the range 0.18% (HR) – 2.79% (ME). In the low demand growth scenario, annual growth rates per market area are in the range of 0.09% (HR) – 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, in the range of 11833 – 16269 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 (4698 MW (referent scenarios) to 6498 MW (high RES scenario), while in relative terms, the largest growth is anticipated in RS (2691 MW in the referent scenario), or 14.4 times more WPP capacity in 2030 than in 2018, and 3414 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 **additional 11014 – 17234 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 (5255 MW – 7155 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, 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. On the level of the entire EMI region, total increase in installed HPP capacity will be significant. In absolute terms **4960 MW of new HPP is expected by 2030, which is a growth of 20%** compared to HPP capacities in 2018.

On the other side of technology, for the entire EMI region, the total decrease in installed TPP capacity will be around 3000 MW. Although significant number, it 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.**

To recap, exected changes from 2018 to 2030 will be significant in almost all power systems. **Total installed capacities will increase for 30% or for more than 24 GW**, with decrease in TPPs and increase in all other technologies. **Dominant installed generation capacity will remain in TPPs: 36.1% in Referent RES scenario and 32.6% in 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 Referent RES scenario and 29.9% in High RES scenario. From 2018 to 2030, share in HPPs will decrease for 3% but share of TPPs will decrease for almost 20%. Share of wind and solar capacities will increase from 14% to 33% or 40%, depending on the aggressiveness of the RES development, and this present 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 is in the range: 18.5% in Referent RES scenario and 20.8% in 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 is in the range: 15.4% in Referent RES scenario and 19.6% in High RES scenario. The highest SPP shares are found, as expected, on the south of the region: in GR (28.4 - 31.1%), MK (16.7 – 21.0%) and BG (21.3 – 24.9%).

Simulations of the market operation of zones in EMI region show that this big change in the structure of the power systems will have an impact on generation mix and especially on generation from fossil fuels fired plants, CO_2 emissions, balance position of the region and each market area as well as on the wholesale market prices.

Comparison of the main market operation indicators for the scenarios with referent and high RES integration have been carried for a couple of 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 hydrological 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

RES generation difference between referent and high RES scenarios at the regional level is 17.6 TWh. It is the difference between 57.7 TWh (ref. RES scenario) and 75.3 TWh (high RES scenario) which is the increase of 30%. Increase per market areas is between 0.2 and 6 TWh (in CGES and IPTO market areas) or between 19% and 278% (in HOPS and ELES market 6areas respectively).

This change in RES generation provokes decrease of TPPs generation, especially lignite and gas fired plants generation at the level of 10%. In all scenarios, this decrease is smaller than increase in RES generation and, with higher RES generation, region increases its export. In all scenarios, higher RES generation provokes larger decrease in generation from gas than from lignite fired plants with decrease in capacity factors (equivalent operating hours with installed capacity divided by 8,760 hours): for lignite fired plants around 2-3% and gas fired plants around 4-5%.

Larger impact on generation mix and TPPs generation is found in CO_2 tax. With higher CO_2 tax lignite fired power plants become less competitive and lignite and gas technologies can change their position in the regional merit order curve. At lignite fired plants capacity factor decrease from the level of 60-70% in case of referent CO_2 tax to 35-50% in case of high CO_2 tax. At gas fired power plants this change has opposite direction and capacity factor increases from 16-30% in referent CO_2 tax case to 36-50% in high CO_2 tax case. **So, this change may jeopardize the economy of the lignite mining, but also old gas fired units. Having this in mind, TSOs and regulators of the EMI region should already start activities in mitigating this efect with the aim to preserve security of supply.**

RES generation (depending on the scenario) supplies between 21% and 27% of total demand (or 28% in case of 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 become the main sources and supplies between 39% and 51% of total demand, or in case of slower demand growth even 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% in case of lower demand growth). **Due to this increase in RES generation, fossil fuel power plants generation is decreased between 11 and 13 TWh (8-12%) and consequently CO_2 emisisons decrease for 6-9 $MtCO_2$ (6-12%).**

EMI region has different net positions in different scenarios **starting from net importer position (3.4 TWh or 1% of total demand) in case of high CO_2 tax, dry hydrology and referent level of RES generation and ending with exporting position (18.4 TWh or 7% of total demand) in case of referent CO_2 tax, average hydrology and high RES generation.**

Changes in balance positions for all market zones show that in almost all zones where lignite powered plants have significant share in generation mix, export is reduced or zone even becomes net importer (NOSBiH, EMS, KOSTT markets areas) due to increase in CO_2 emission tax. Market areas where gas powered plants have high impact on generation mix, export increases (Transelectrica market area) or import decreases (HOPS market area). IPTO market area, due to significant generation capacities in gas technology, even becomes net exporter in case of high CO_2 tax.

Average regional **wholesale market prices are expected in the range between 47.4 and 70.5 EUR/MWh** with decrease provoked by high RES integration of around 2 EUR/MWh or 4% in all scenarios. **Main driver for higher prices is CO_2 tax:** increase of CO_2 tax from 27 EUR/tCO_2 to 53 EUR/tCO_2 would lead to wholesale market prices increase in EMI region in 2030 for around 18 EUR/MWh or to increase of 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 case of referent CO_2 tax there are 4 price zones in EMI region disregarding hydrology, demand growth or level of RES:

1) IPTO, 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 but between central zones and IPTO
4) All other zones

In the case of high CO_2 tax, balance positions of the zones are changed and practically all zones are 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 EMI market zones in SEE provides enough flexibility to cope with hourly variablility in RES generation. The confirmation of this can be found in the fact that there are no spillages or curtailments in wind, solar or hydro generation in analysed scenarios.

Additional gas-fired generation capacities do not change regional generation mix significantly but they compensate generation from older and less competitive TPPs and at the same time provide flexibility to the power system in order to utilize RES and hydro resources in technical and economical more efficient way.

Based on the above mentioned market analyses selected power system snapshots are taken out and transferred to the network analyses. Snapshot selection is done to represent the most critical network conditions. **Based on the TSOs and market analyses inputs we managed to create robust and verified regional power system model consisting of:**

- **8578 buses**
- **10050 branches**
- **3360 loads**
- **1521 power plants**
- **3745 transformers**
- **149 switched shunts**
- **4 DC lines**

Using this robust and verified model we found out 73 contingency cases in 11 analyzed RES integration scenarios. All of it appears 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 Slovenian border to Italy)
- 11 internal lines and
- 3 transformers

8 critical tie lines are found both in 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

11 critial internal lines are also found both in 400 kV network (3 lines) and 220 kV network (8 lines). These elements are located in the following countries:

- Albania (2 lines on 220 kV level)
- 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)
- Bulgaria (3 lines, one on 400 kV and 2 on 220 kV level) and
- Bosnia and Herzegovina (2 lines on 220 kV)

3 transformers are detected as critical in the region, two in Croatia, one in Romania.

Among all above mentioned 22 critical elements there are 6 elements with severe overloadings (130% of rated current) in one or more scenarios. 3 elements appear to be overloaded in the base cases (with all elements available).

8 out of 11 EMI TSOs can expect to face certain network bottlenecks in high RES scenarios in 2030 (AL, BA, BG, HR, GR, ME, RO and SI). These results show that in given scenarios only TSOs of MK, RS and XK will not face any network bottlenecks with high RES integration as foreseen in this analysis.

The highest number of outages in one scenario is 8 and it is found in scenario 5. Clearly, there is no scenario with extremely high number of contingencies which is good sign of network robustness.

Network models are based on official TSOs' 10-year network development plans. This analysis assumed significant changes till 2030 in all power systems, including additional 25% of RES capacities on top of RES capacities already included in official 10-year network development plans. **Total installed capacities will increase for 30% or for more than 24000 MW.**

Therefore**, in the network with more than 10000 elements and only 22 bottlenecks that are found in the region in all 11 scenarios, we can conclude that regional network is quite robust and solid for future absorption of additional RES capacities from the steady state perspective. Other aspects of large scale RES integration such as system balancing or dynamics issues are not analyzed in this study. Regional perspective of these aspects should be covered in the future studies.**

Finally, this region consists of mainly small systems (with few exceptions) and its mutual impact is quite significant. At the same time, there are no combined market and network analyses on this level of details that could support internal market and network development plans with additional information on the regional perspective. So, regional studies like this one are very valuable both from the regional and internal perspective, for the TSOs, MOs, policy makers and investors.

8. APPENDIX

8.1. Market database

8.1.1. OST market area

OST market area – Demand

Forecasted consumption in the OST market area is at a level of 9.5 TWh in 2030 (Table 33). The highest consumption is observed in the winter (December, January), while the lowest consumption is in the mid-spring and autumn (May, September), as depicted in Figure 252. Since the TSO did not provide the dataset for the hourly load profile in 2030, it was taken from the previous EMI study.

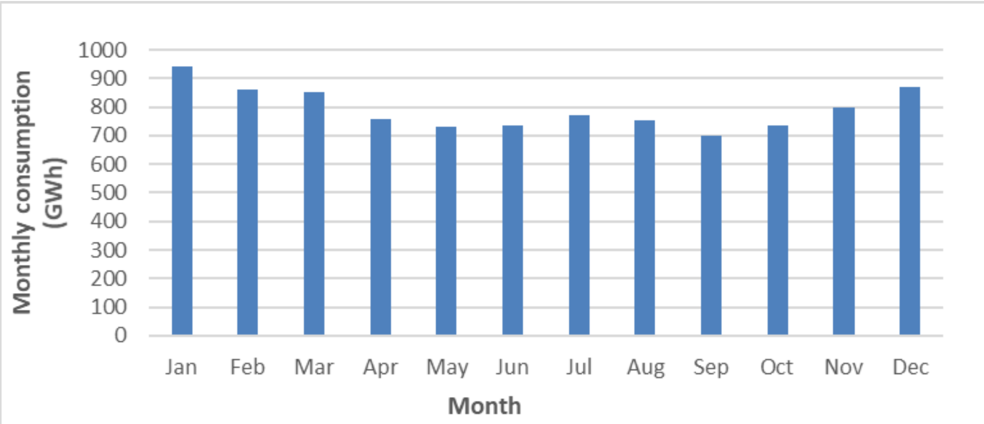


Figure 252: Monthly energy consumption (GWh) for 2030 – OST market area

Total consumption in the Referent scenario is expected to reach 9.5 TWh, while in the low demand scenario, with a reduced growth rate, total annual consumption would be 8.3 TWh, as shown in Table 33.

Table 33: Referent and low demand scenarios in 2030 – OST market area

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

OST market area – Production

For the OST market area, we have confirmed that two new units of TPP Vlora will be in operation in 2030. Wind and solar power plants will participate with 384 MW and 445 MW, respectively (Table 34).

Table 34: Installed capacities per technology in 2030 – OST market area

Technology	Installed capacity (MW)	
	2018	2030
Thermal – gas	0	300
Hydro	1912	2949
Wind	0	384/480[6]
Solar	0	445/557[6]

In 2030, the OST market area will still be highly dependent on hydro production, with 72% of the installed capacity in HPPs. This is much less than in 2018, when it was 100%. The remaining 28% of generation capacity will be divided between other generation technologies such as thermal, wind and solar (Figure 253).

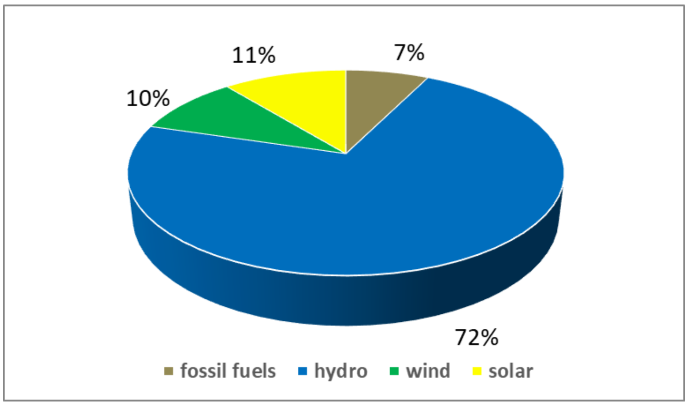


Figure 253: Installed capacity per fuel type in 2030 – OST market area

Table 35 shows the average annual capacity factors for wind and solar power plants in Albania. Since hourly profiles of capacity factors for wind and solar generation were not available, we used data on capacity factors from the MEPSO market area for OST.

Table 35: Adopted average wind and solar capacity factors for 1982, 1984 and 2007 – OST market area

[6] Installed capacities expected in Referent/High RES Scenarios

OST market area – average wind and solar capacity factors			
Year	**1982**	**1984**	**2007**
Wind CF	19.71%	21.61%	21.72%
Solar CF	15.69%	15.23%	15.76%

Regarding new hydro plants, the missing yearly to monthly generation breakdown is based on data from OST. Table 36 shows the annual generation of all HPPs in the OST market area for different hydrological conditions.

Table 36: Annual generation for all HPPs for dry and average hydrology in 2030 – OST market area

Annual generation (GWh)	Dry	Average
ROR	2208	2068
HPPs with reservoirs	4978	6410
Total	7186	8478

8.1.2. NOSBiH market area

NOSBiH market area – Demand

Considering the currently low levels of demand in the NOSBiH market area, it is expected that the demand will moderately grow. The peak load in the NOSBiH market area in 2030 will be around 2,290 MW, with the minimum load expected to be about 800 MW (Figure 254). The highest consumption is observed during the winter months, while in spring and September, electricity consumption is at the lowest levels, as also depicted in Figure 254.

The hourly dataset with load time series for all three climatic years was provided by the NOSBiH.

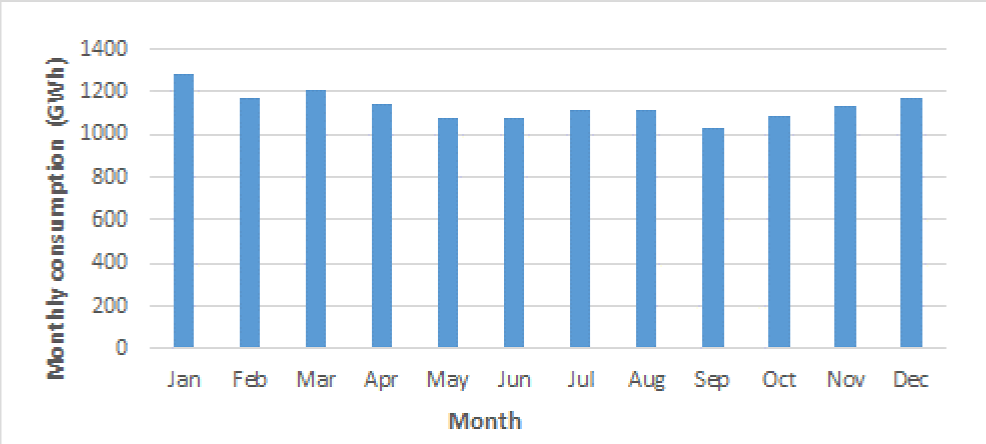


Figure 254: Monthly energy consumption (GWh) for 2030 – NOSBiH market area

Total consumption in the Referent scenario is expected to grow at just 0.62% per year, and reach about 13.6 TWh in 2030, while in the low demand scenario, with an even lower growth rate (0.31%), the total annual consumption would be approximately 13.08 TWh (Table 37).

Table 37: Referent and low demand scenarios in 2030 – NOSBiH market area

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)
BA	12.6	0.62%	13.57	0.31%	13.08

NOSBiH market area – Production

For the NOSBiH market area, NOSBiH provided all necessary data related to TPPs and HPPs.

The TPPs in the NOSBiH market area are dominated by locally sourced coal-fired power plants. No new gas-fired TPPs are expected. Some of existing TPP units will be decommissioned by 2030, but also the addition of new lignite units at TPP Tuzla and TPP Kakanj is expected. In the net sum, there is not going to be significant change in TPPs installed capacities.

The NOSBiH market area also has significant wind resources, and it is assumed that in 2030, 580 MW of wind power plants will be online. Concerning solar power plants, we expect 100 MW by 2030, which is 90 MW more than in 2018. Installed capacities for the different technologies in the NOSBiH market area are given in Table 38.

Table 38: Installed capacities per technology in 2030 – NOSBiH market area

Technology	Installed capacity (MW)	
	2018	2030
Thermal – lignite	1850	1932
Hydro	2100	2493
Wind	51	650/812[6]
Solar	10	200/250[6]

As can be seen in Figure 255, the NOSBiH market area has significant hydro resources as well. The capacity of HPPs represents near half of the total generation capacity.

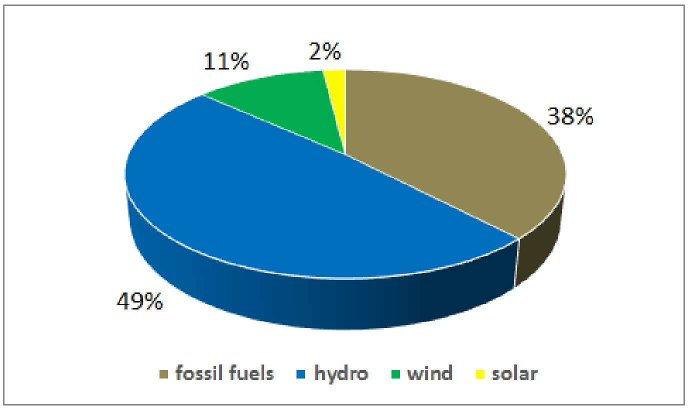


Figure 255: Installed capacity per fuel type in 2030 – NOSBiH market area

On the basis of provided hourly profiles for wind and solar generation, the average capacity factors for typical climatic years are given in Table 39.

Table 39: Average wind and solar capacity factors for 1982, 1984 and 2007 – NOSBiH market area

NOSBiH market area – average wind and solar capacity factors			
Year	**1982**	**1984**	**2007**
Wind CF	19.53%	21.64%	19.35%
Solar CF	15.41%	15.20%	15.79%

NOSBiH provided the hydro generation for average and dry hydrology. The total annual generation for Run of River (ROR) and storage HPP (HPPs with reservoir) are given in Table 40.

Table 40: Annual generation for all HPPs for dry and average hydrology – NOSBiH market area

Annual generation (GWh)	Dry	Average
ROR	2832	3742
HPPs with reservoirs	2231	2694
Total	5063	6435

Table 41 provides data regarding the single PSHPP in the NOSBiH market area. All values were provided by the NOSBiH.

Table 41: PSHPP data – NOSBiH market area

Name	Number of units	Pgen (MW)	Ppump (MW)	Efficiency
PSHPP Čapljina	2	220	220	74%

8.1.3. ESO EAD market area

ESO EAD market area – Demand

The forecasted consumption in the ESO EAD market area is 37.4 TWh in 2030 (Table 42). The observed peak load is 7054 MW with a load factor of 60.93%, while the minimum load is about 2443 MW. The highest monthly consumption is observed during winter, while the lowest consumption is present in spring and September, although a rather flat profile can be observed in the central part of the year (Figure 256).

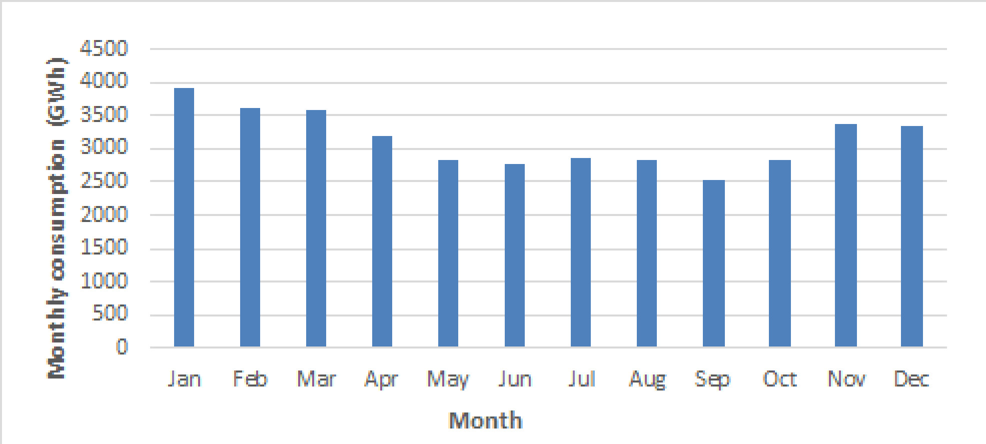


Figure 256: Monthly energy consumption (GWh) for 2030 – ESO EAD market area

Total consumption in the Referent scenario is expected to be 37.4 TWh, while in the low demand scenario, with a reduced growth rate by the half, the annual consumption would be 35.69 TWh (Table 42).

Table 42: Referent and low demand scenarios in 2030 – ESO EAD market area

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)
BG	34.1	0.76%	37.35	0.38%	35.39

ESO EAD market area – Production

In 2030, the ESO market area will have a balanced and diversified electricity production mix. Around 51% of installed capacity is in thermal plants, most of them are base load plants (nuclear and lignite). Installed capacity in renewables (wind and solar) will rise to 3,816 MW in 2030, while hydro generation will amount approximately 22% of total installed capacity (Table 43 and Figure 257). Also, the only hard coal-fired thermal power plant (TPP Sliven) will be decommissioned by 2030.

Table 43: Installed capacities per technology in 2030 – ESO EAD market area

Technology	Installed capacity (MW)

	2018	2030
Thermal - lignite	3894	2508
Thermal - gas	1368	2611
Thermal - hard coal	30	0
Thermal - nuclear	2150	2150
Hydro	3207	3207
Wind	712	887/1109[6]
Solar	1059	2929/3661[6]

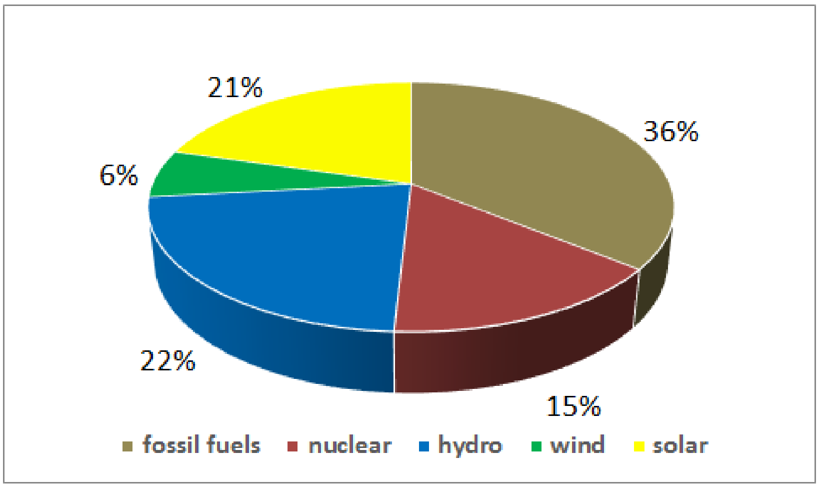


Figure 257: Installed capacity per fuel type in 2030 – ESO EAD market area

Table 44 shows the average annual capacity factors for wind and solar power plants, which we have calculated on the basis of the time series provided by the ESO.

Table 44: Average wind and solar capacity factors for 1982,1984 and 2007 – ESO EAD market area

ESO EAD market area – average wind and solar capacity factors			
Year	**1982**	**1984**	**2007**
Wind CF	19.79%	19.93%	21.20%
Solar CF	14.48%	14.25%	14.33%

We provide the annual generation for all HPPs in different hydrological conditions in Table 45. ESO did not provide generation data for dry hydrological conditions, so we calculated these values, using 25% lower values for dry hydrology.

Table 45: Annual generation for all HPPs for dry and average hydrology – ESO EAD market area

Annual generation (GWh)	Dry	Average
ROR	1280	1706
HPPs with reservoirs	2356	3145
Total	3638	4851

Table 46 shows the essential data needed for modeling PSHPP in ESO EAD market area in 2030. In this case, the consultant estimated the efficiency of PSHPP, while ESO provided other data.

Table 46: PSHPP data – ESO EAD market area

Name	Number of units	Pgen (MW)	Ppump (MW)	Efficiency
PSHPP Chaira	4	216	198	75%
PSHPP Belmeken	2	75	52	75%
PSHPP Orfei	1	40	40	75%

8.1.4. HOPS market area

HOPS market area – Demand

In the HOPS market area, it is expected that the peak load in 2030 will be around 3,000 MW, with the minimum load of around 1,300 MW. From the pattern of monthly consumption in the HOPS market area, it is clear that the air conditioning (cooling) usage in the hottest summer months has a significant impact. For this reason, July and August are significantly higher in energy usage than June and September, as depicted in Figure 258.

The dataset related to the HOPS market area hourly load profile in 2030 was taken from the TYNDP 2018 scenario Best Estimate 2025 used in the previous EMI study and then adjusted to the expected annual demand in 2030 given by the TSO.

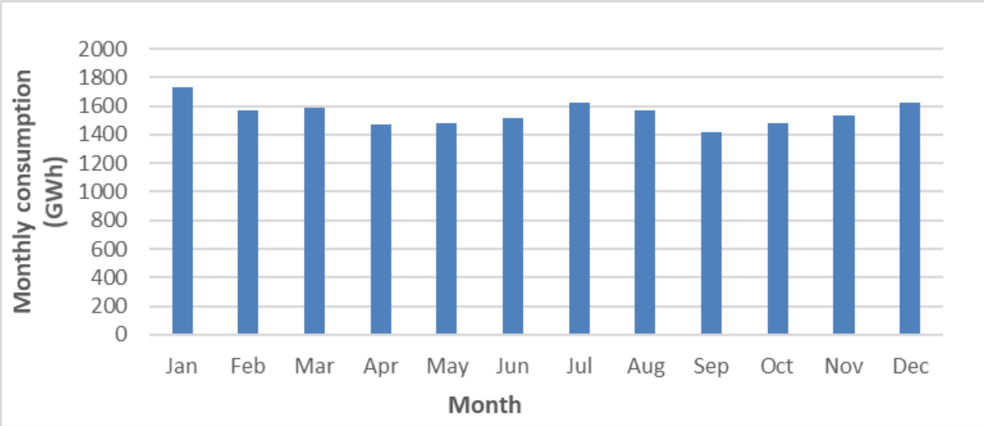


Figure 258: Monthly energy consumption (GWh) for 2030 – HOPS market area

Total consumption in the Referent scenario in 2030 is expected to be 18.6 TWh, while in the low demand scenario, with a reduced growth rate, total annual consumption would be around 18.4 TWh, as given in Table 47.

Table 47: Referent and low demand scenarios in 2030 – HOPS market area

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)
HR	18.2	0.18%	18.6	0.09%	18.40

HOPS market area – Production

The dataset provided by the TSO omitted certain information regarding some TPPs, such as the fuel price, variable O&M cost, as well as generation of new HPPs (dry hydrology). We took the additional data related to TPPs from the TYNDP 2020 ENTSO-E database.

As can be seen from Table 48, the HOPS market area in 2030 will be dominated by hydro power plants. The TPPs in HOPS market area are expected to have about 16% share of installed capacity by then, and among the TPPs only the Plomin TPP in the Istria region will run on imported coal, while the rest of the TPPs will exclusively run on natural gas.

Table 48: Installed capacities per technology in 2030 – HOPS market area

Technology	Installed capacity (MW)	
	2018	2030
Thermal - gas	1924	981
Hydro	2164	3302
Wind	582	1300/1500[6]
Solar	60	600/800[6]

In 2030 wind power plants exceed the share of TPPs, while solar power plants participate with 10% in total generation capacities (Figure 259), which gives a total of 32% of installed capacity from wind and solar power plants. The largest generation capacity is installed in hydro power plants (52%), which gives in total 84% of total installed generation capacity in RES in Croatia in 2030.

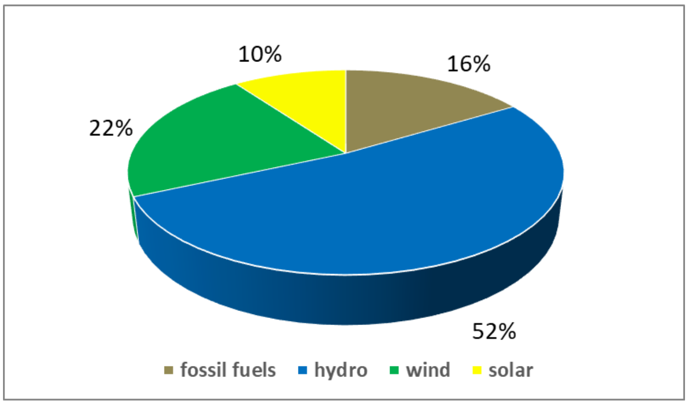


Figure 259: Installed capacity per fuel type in 2030 – HOPS market area

Hourly time series and capacity factors for wind and solar generation in Croatia in 2030 were given by HOPS. These input data are based on the last few years of operational wind and solar power plants experience in Croatia covering all three typical climate years, as shown in *Table 49*.

Table 49: Adopted average wind and solar capacity factors for 1982, 1984 and 2007 – HOPS *market area*

HOPS market area – average wind and solar capacity factors			
Year	**1982**	**1984**	**2007**
Wind CF	26.00%	26.00%	26.00%
Solar CF	16.00%	16.00%	16.00%

Regarding hydro generation, the TSO provided data for hydrology for the existing power plants. We estimated the hydro generation for the new HPPs assumed to be in operation in 2030 in line with HPPs with similar characteristics and sizes. In accordance with historical data, dry hydrological conditions are assumed to be 25% lower in comparison to the generation in average conditions. Annual generation of the portfolio of hydro power plants in HOPS market area for different hydrological conditions is in Table 50.

Table 50: Annual generation for all HPPs for dry and average hydrology – HOPS market area

Annual generation (GWh)	Dry	Average
ROR	2126	2835
HPPs with reservoirs	3285	4380
Total	5411	7215

Table 51: PSHPP data – HOPS market area. Table 51 shows essential data for the modeling of PSHPP in the Antares software tool. In the case of the HOPS market area, we estimated the efficiency of PSHPP to be 75%, while HOPS provided data on the number of units and generation capacity.

Table 51: PSHPP data – HOPS market area

Name	Number of units	Pgen (MW)	Ppump (MW)	Efficiency
PSHPP Fužina	1	4.6	5.7	75%
PSHPP Lepenica	1	0.8	1.2	75%
PSHPP Velebit	2	138.0	120.0	75%
PSHPP Blato	3	3.5	3.4	75%
PSHPP Vrdovo	1	540	490	75%

8.1.5. ADMIE/IPTO market area

ADMIE/IPTO market area – Demand

The forecasted annual consumption in 2030 in Greece is 62.4 TWh, with a load factor of 56.55% (Figure 260). The monthly consumption ratio is well balanced, with the highest values observed in the summer season from June to August, and the winter season from December to March (Figure 260). Peak load is 12,795 MW and the minimum is around 4,560 MW.

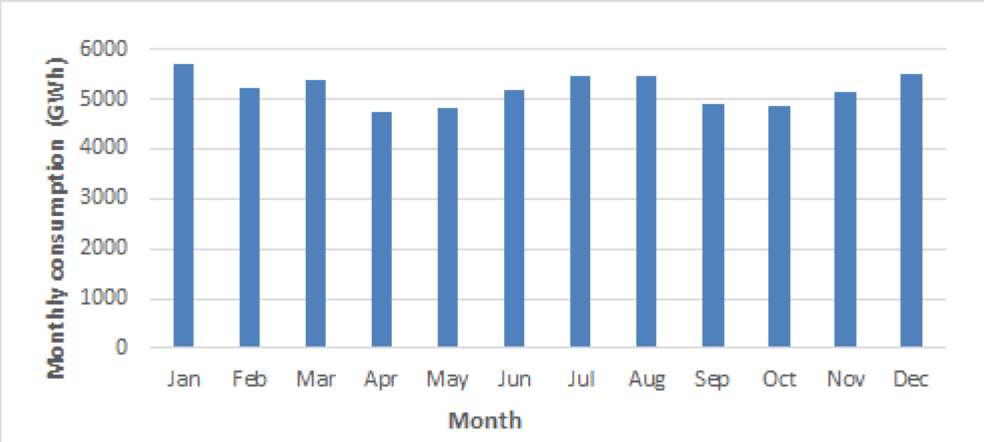


Figure 260: Monthly energy consumption (GWh) for 2030 – ADMIE/IPTO market area

Total consumption in the Referent scenario in 2030 is expected to be 62.4 TWh, while in the low demand scenario, as provided by the TSO, the total annual consumption would be 59.22 TWh (Table 52).

Table 52: Referent and low demand scenarios in 2030 – ADMIE/IPTO market area

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)
GR	51.6	1.6%	62.44	1.15%	59.22

ADMIE/IPTO market area – Production

In 2030, the ADMIE/IPTO market area will have highly diversified production mix with 7,000 MW of installed generation in wind and 7,700 MW in solar, which will give the ADMIE/IPTO market area the largest renewable wind and solar generation fleet in the region, with a share of 54% in total installed capacity. Thermal power plants will comprise 29% of total installed capacity, and most of them will be gas-fired plants. The share of HPPs is around 17% (Table 53 and Figure 261).

Table 53: Installed capacities per technology in 2030 – ADMIE/IPTO market area

Technology	Installed capacity (MW)	
	2018	2030
Thermal - lignite	3870	0
Thermal - gas	5213	7478
Thermal - heavy oil	327	98
Thermal - light oil	381	310
Hydro	3413	4545
Wind	2302	7000/8800[6]
Solar	2445	7700/9600[6]

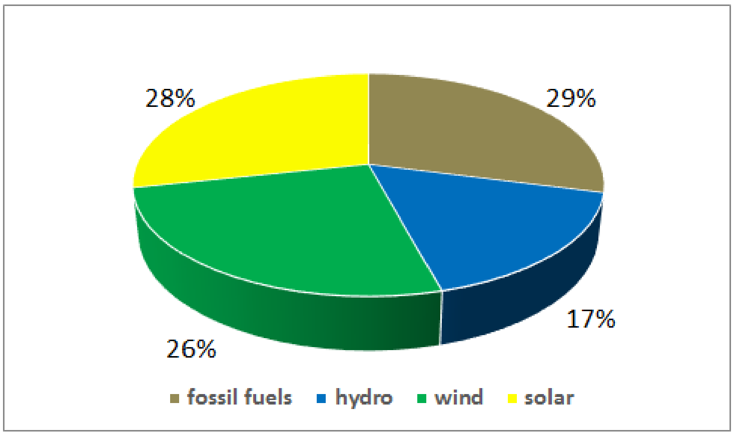


Figure 261: Installed capacity per fuel type in 2030 – ADMIE/IPTO market area

Table 54 shows the annual average wind and solar capacity factors. As expected, ADMIE/IPTO market area has one of the highest solar capacity factors in the region, over 18%.

Table 54: Average wind and solar capacity factors for 1982,1984 and 2007 – ADMIE/IPTO market area

ADMIE/IPTO market area – average wind and solar capacity factors			
Year	**1982**	**1984**	**2007**
Wind CF	21.47%	16.66%	19.65%
Solar CF	17.94%	17.72%	18.21%

In the case of hydro power plants, IPTO provided the expected generation for dry and average hydrology only. These aggregated values for RoR and HPPs with reservoirs will be used for modeling of ADMIE/IPTO market area in ANTARES (Table 55).

Table 55: Annual generation for all HPPs for dry and average hydrology

Annual generation (GWh)	Dry	Average
ROR	914	1219
HPPs with reservoirs	2500	4560
Total	3414	5779

Table 56 shows data related to PSHPPs in ADMIE/IPTO market area. TSO provided all necessary data needed for modeling of pumped storage hydro power plants.

Table 56:PSHPP data – ADMIE/IPTO market area

Name	Number of units	Pgen (MW)	Ppump (MW)	Efficiency
PSHPP Sfikia	3	105	105	70%
PSHPP Thisavros	3	128	128	70%
PSHPP Amfilochia	1	680	680	72%

8.1.6. KOSTT market area

KOSTT market area – Demand

Expected annual consumption in the KOSTT market area in 2030 is 6.85 TWh. The highest monthly consumption is expected in the winter (December, January), while the lowest consumption is present from May to September (Figure 262).

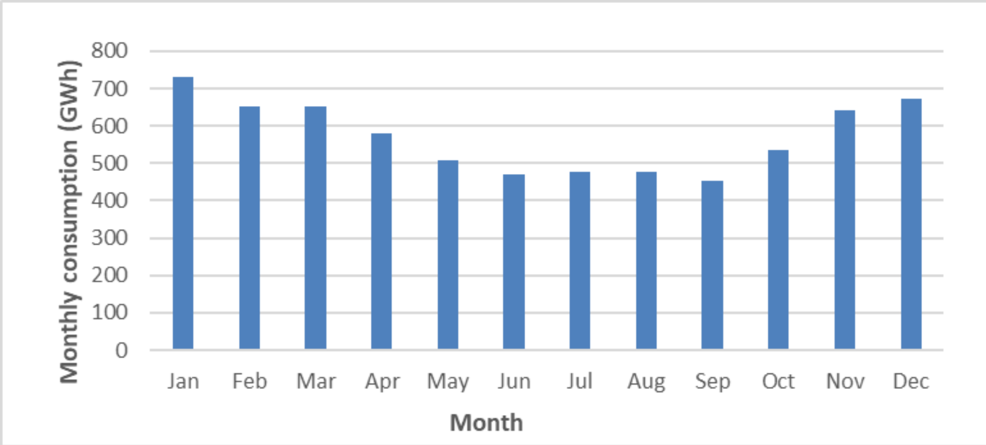


Figure 262: Monthly energy consumption (GWh) for 2030 – KOSTT market area

Total consumption in the Referent scenario is expected to reach 6.85 TWh, while in the low demand scenario, with a reduced growth rate, total annual consumption would be 6.22 TWh (Table 57).

Table 57: Referent and low demand scenarios in 2030 – KOSTT market area

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)
XK	5.58	1.90%	6.85	0.95%	6.22

KOSTT market area – Production

In 2030, in the KOSTT market area approximately half of the generation capacity will be based on lignite plants, with a share of 52% in total installed capacity. The share of wind and solar will be around 26%, while the share of HPPs will be 22% (Table 58 and Figure 263).

Table 58: Installed capacities per technology in 2018 and 2030 – KOSTT market area

Technology	Installed capacity in 2018(MW)	Installed capacity in 2030 (MW)
Thermal - lignite	960	978
Hydro	64	424
Wind	36	336/500[6]
Solar	7	150/250[6]

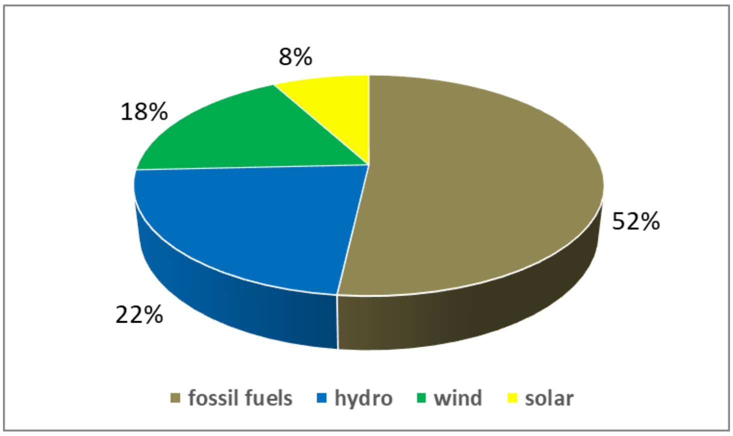


Figure 263: Installed capacity per fuel type in 2030 – KOSTT market area

Table 59 shows the average annual capacity factors for wind and solar power plants, calculated on the basis of the time series provided by KOSTT. In addition, it is interesting to note that the KOSTT market area has high average wind capacity factors in all three typical climatic years.

Table 59: Average wind and solar capacity factors for 1982,1984 and 2007 – KOSTT market area

KOSTT market area– average wind and solar capacity factors			
Year	**1982**	**1984**	**2007**
Wind CF	20.92%	24.61%	22.61%
Solar CF	15.66%	15.23%	15.88%

Table 60 shows the annual generations of all existing HPPs in the KOSTT market area for different hydrological conditions. KOSTT did not provide generation for dry hydrological conditions, so we have calculated them, as for several other market areas, by multiplying the average generation with a coefficient of 0.75. For new HPPs, generation data for both hydrological conditions were not provided by the TSO.

Table 60: Annual generation for all HPPs for dry and average hydrology – KOSTT market area

Annual generation (GWh)	Dry	Average
ROR	65	87
HPPs with reservoirs	63	84
Total	128	171

Table 61 contains data provided by TSO which will be used for modeling the new PSHPP Zhur in ANTARES software. In the case of the KOSTT market area, we estimated the efficiency of PSHPP.

Table 61: PSHPP data – KOSTT market area

Name	Number of units	Pgen (MW)	Ppump (MW)	Efficiency
PSHPP Zhur	4	250	250	75%

8.1.7. MEPSO market area

MEPSO market area – Demand

In the MEPSO market area, expected annual consumption in 2030 is 9.2 TWh. Figure 264 shows that the highest monthly consumption is expected in January, while the lowest consumption is anticipated at the beginning and at the end of summer. The forecasted peak load for 2030 is 1649 MW, giving a load factor of 63.7%.

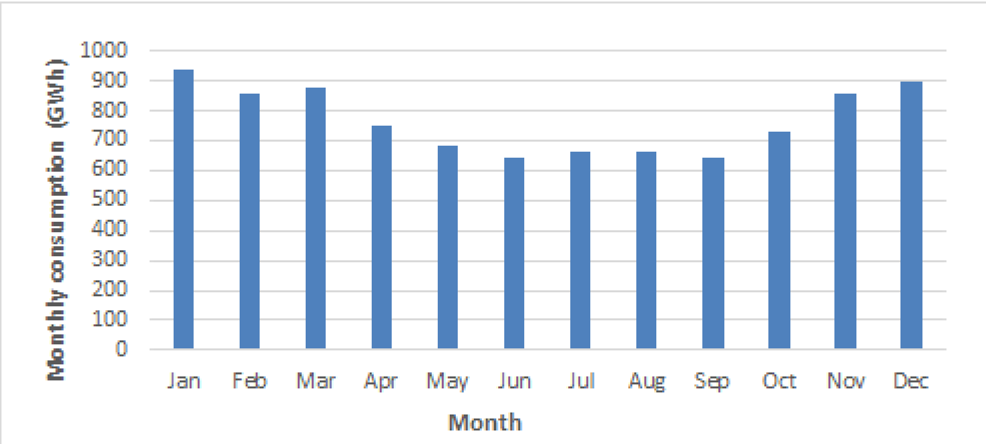


Figure 264: Monthly energy consumption (GWh) for 2030 – MEPSO market area

Total consumption in 2030 in the Referent scenario is expected to be 9.2 TWh, while in the low demand scenario, with a reduced growth rate, the total annual consumption would be 8.96 TWh, as it was reported by TSO and which is in accordance with the "The Strategy for Energy Development of the Republic of North Macedonia until 2040"[7] (Table 62).

Table 62: Referent and low demand scenarios in 2030 – MEPSO market area

[7] http://economy.gov.mk/Upload/Documents/Energy%20Development%20Strategy_FINAL%20DRAFT%20-%20For%20public%20consultations_ENG_29.10.2019(3).pdf

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)
MK	7.2	2.07%	9.2	1.85%	8.96

MEPSO market area – Production

In 2030, the MEPSO market area's hydro-thermal production mix will stay balanced, with around 30% of generation capacities installed in wind and solar power plants. Base load plants (lignite) will still represent the largest group of thermal units in terms of installed capacities (Table 63 and Figure 265).

Note that only lignite and gas-fired thermal power plants exist in 2030.

Table 63: Installed capacities per technology in 2030 – MEPSO market area[8]

Technology	Installed capacity (MW)	
	2018	2030
Thermal - lignite	759	426
Thermal - gas	316.5	336.5
Thermal - heavy oil	198	0
Hydro	693	900
Wind	37	306/366[6]
Solar	17	403/550[6]

[8] All installed capacities are in accordance with revised values provided by MEPSO

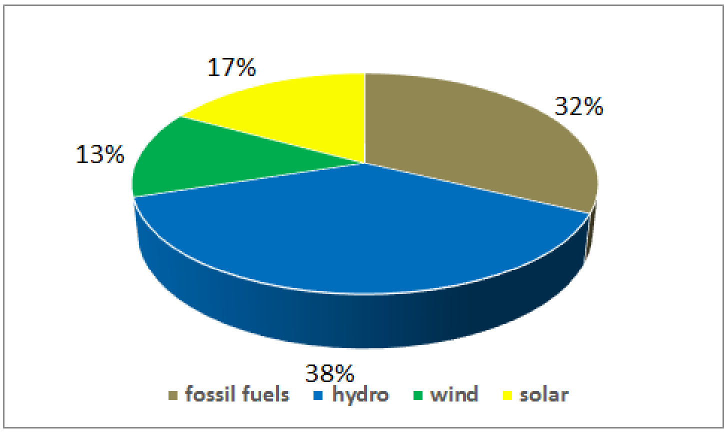


Figure 265: Installed capacity per fuel type in 2030 – MEPSO market area

Table 64 presents the average annual capacity factors for wind and solar power plants, while at Table 47 annual generation of all HPPs for dry and average hydrological conditions are presented, both were provided by MEPSO.

Table 64: Average wind and solar capacity factors for 1982, 1984 and 2007 – MEPSO market area

MEPSO market area – average wind and solar capacity factors			
Year	**1982**	**1984**	**2007**
Wind CF	19.71%	21.61%	21.72%
Solar CF	15.69%	15.23%	15.76%

Table 65: Annual generation for all HPPs for dry and average hydrology – MEPSO market area

Annual generation (GWh)	Dry	Average
ROR	207	295
HPPs with reservoirs	1238	1768
Total	1444	2063

8.1.8. CGES market area

CGES market area – Demand

Total consumption in the Referent scenario in the CGES market area is expected to be 4.73 TWh, while in the low demand scenario, with a lower growth rate, the total annual consumption would be 4.01 TWh (Table 66).

The forecasted peak load for 2030 is 909 MW, giving the load factor of 59.34%. In the winter season (November - March), the highest monthly consumption, above 400 GWh is expected, while in summer (June - September), the forecasted monthly consumption is below 400 GWh (Figure 266).

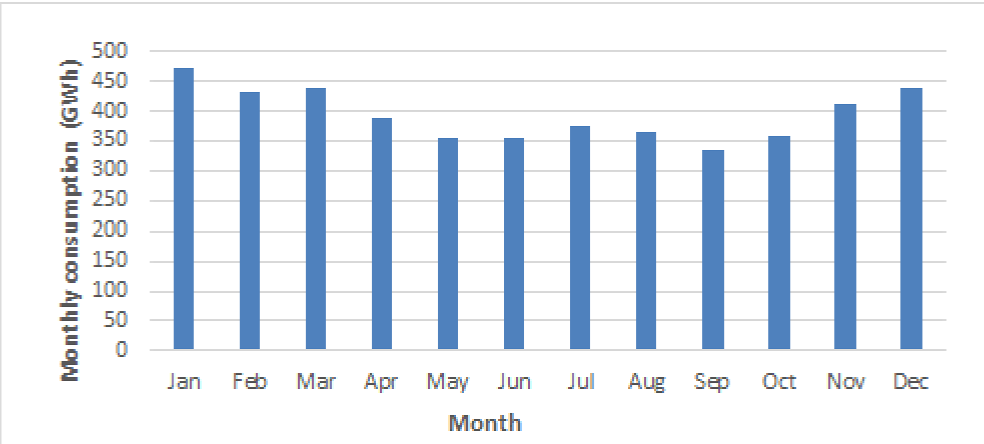


Figure 266: Monthly energy consumption (GWh) for 2030 – CGES market area

Table 66: Referent and low demand scenarios in 2030 – CGES market area

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)
ME	3.4	2.79%	4.73	1.39%	4.01

CGES market area – Production

In 2030, the highest share of installed generation capacity in the CGES market area will be in HPPs - around 61%, while the TPP capacity share will be just 12%. In addition, we envisage 243 MW of wind and 250 MW of solar capacity, which gives 27% of solar and wind power plants in total installed generation capacity 2030 (Table 67 and Figure 267). Together with large hydro, total RES share in installed generation capacity in Montenegro in 2030 will be 88%.

Table 67: Installed capacities per technology in 2030 – CGES market area

Technology	Installed capacity (MW)	
	2018	2030
Thermal - lignite	225	225
Hydro	649	1117
Wind	118	243/304[6]
Solar	0	250/313[6]

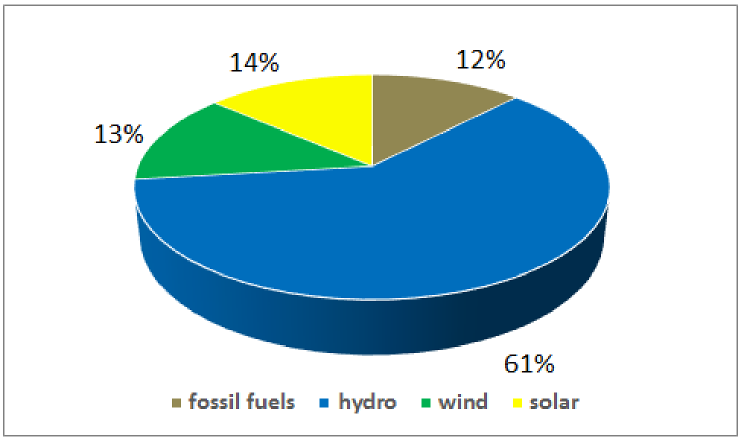


Figure 267: Installed capacity per fuel type in 2030 – CGES market area

The average wind and solar capacities for relevant climatic years are given in Table 68. The annual generation for dry and average hydrology provided by TSO is given in Table 69. For new HPPs, we calculated values for dry hydrological conditions by multiplying average value with a coefficient of 0.75. Also, it should be noted that all HPPs within the CGES market area are HPPs with reservoirs.

Table 68: Average wind and solar capacity factors for 1982, 1984 and 2007 – CGES market area

CGES market area – average wind and solar capacity factors			
Year	**1982**	**1984**	**2007**
Wind CF	18.94%	21.70%	19.32%
Solar CF	15.68%	15.27%	15.83%

Table 69: Annual generation for all HPPs for dry and average hydrology – CGES market area

Annual generation (GWh)	Dry	Average
ROR	0	0
HPPs with reservoirs	1611	2856
Total	1611	2856

8.1.9. Transelectrica market area

Transelectrica market area – Demand

The Transelectrica market area is one of the largest in SEE, both in terms of load and production.

The highest monthly consumption is observed during the winter– in months of January or December, while the lowest monthly consumption is present in September or June, as depicted in Figure 268.

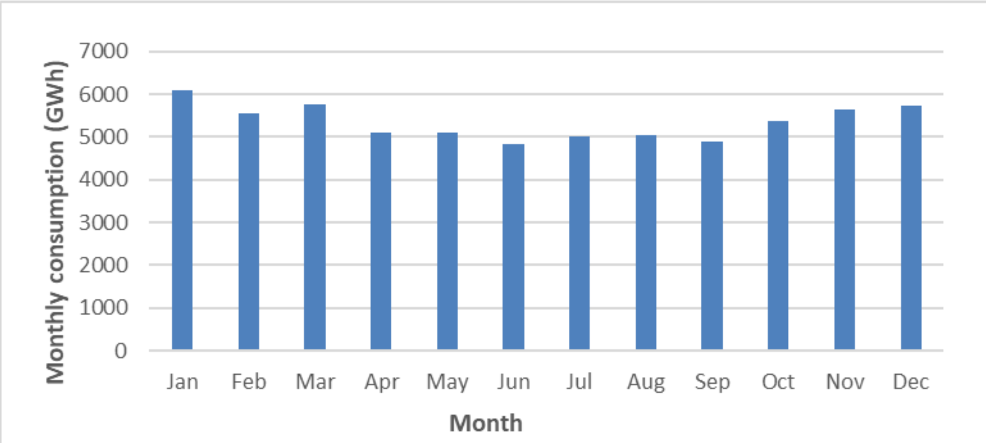


Figure 268: Monthly energy consumption (GWh) for 2030 – Transelectrica market area

Total consumption in the Referent scenario is expected to reach 63.5 TWh in 2030, while in the low demand scenario, with a reduced growth rate, total annual consumption would be around 60.7 TWh (Table 70).

Table 70: Referent and low demand scenarios in 2030 – Transelectrica market area

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)
RO	57.9	0.81%	63.50	0.40%	60.70

Transelectrica market area – Production

Table 71 provides data on the installed generation capacities in 2030 in the Transelectrica market area by technology. The share of TPP capacity will be around 29% of the total. Nuclear power is prominent in the Transelectrica market area's generation mix although its share will be just 9% of installed capacity. Hydropower will have a significant share of capacity – 31%.

Table 71: Installed capacities per technology in 2018 and 2030 – Transelectrica market area

Technology	Installed capacity in 2018 (MW)	Installed capacity in 2030 (MW)
Thermal - lignite	3073	3073
Thermal - gas	2672	2835
Thermal - hard coal	1032	412
Nuclear	1300	1965
Hydro	6420	6742
Wind	2977	4200/5100[6]
Solar	1262	2000/3700[6]
Biomass	121	350

Renewable power is expected to play a very significant role in the Transelectrica market area, since wind and solar power will almost have a share of 29% in the generation mix in 2030. In specific, wind power plants will contribute with 20%, while solar power plants with 9% of generation capacities. Besides wind and solar, another renewable source will contribute to the generation mix – biomass, with a share of 2%. Detailed representation of generation mix in the Transelectrica market area is given in Figure 269.

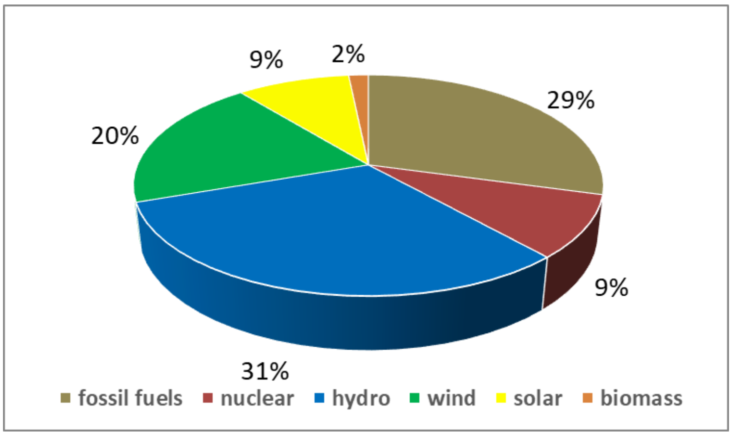


Figure 269: Installed capacity per fuel type in 2030 – Transelectrica market area

On the basis of Transelectrica's hourly profiles of capacity factors for wind and solar generation, the average capacity factors for different climatic years are given in Table 72.

Table 72: Average wind and solar capacity factors for 1982, 1984 and 2007 – Transelectrica market area

Transelectrica market area – average wind and solar capacity factors			
Year	**1982**	**1984**	**2007**
Wind CF	24,68%	27,67%	27,74%
Solar CF	19,31%	18,82%	19,48%

Transelectrica provided the hydro generation for average and dry hydrology. The total annual generations for Run of River (ROR) and storage HPPs (with reservoir) are given in Table 73.

Table 73: Annual generation for all HPPs for dry and average hydrology – Transelectrica market area

Annual generation (GWh)	Dry	Average
ROR	8297	10371
HPPs with reservoirs	4443	5553
Total	12739	15924

8.1.10. EMS market area

EMS market area – Demand

Forecasted consumption in the EMS market area (excluding the KOSTT market area) is 38.95 TWh in 2030 (Table 74), and the expected peak load is 6654 MW, with a load factor of 67.18%. The highest monthly consumption is anticipated in the winter season (December, January), while the lowest consumption will occur from midspring to early autumn (May - September), as shown in Figure 270.

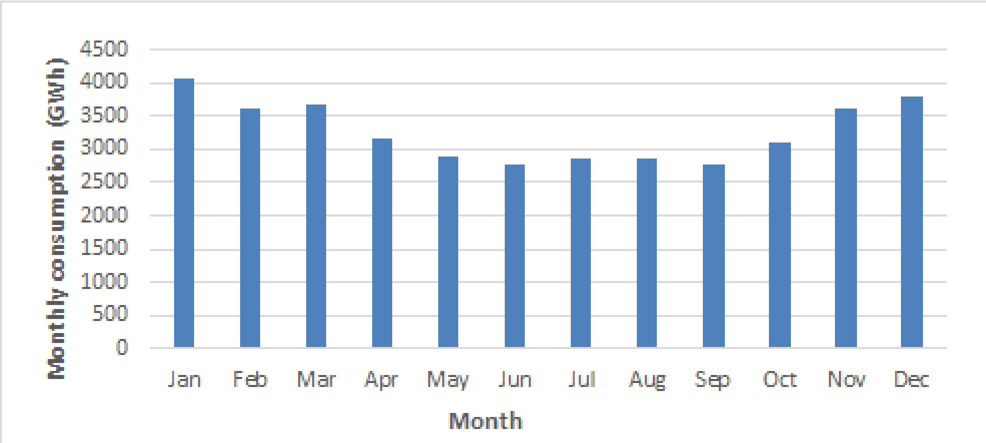


Figure 270: Monthly energy consumption (GWh) for 2030 – EMS market area

Total consumption in the Referent scenario is expected to be 38.95 TWh, while in the low demand scenario, with a reduced growth rate, total consumption in 2030 would be 36.88 TWh (Table 74).

Table 74: Referent and low demand scenarios in 2030 – EMS market area

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)
RS	34.9	0.92%	38.95	0.46%	36.88

EMS market area – Production

In 2030, the EMS market area production portfolio (excluding the KOSTT market area) will be shared between thermal (still based on lignite), hydro and wind power plants. As can be seen, the penetration of solar power into the EMS system is expected to be very low (less than 1%). Capacities of TPPs take almost one half of the generation mix (45%) while hydro and wind power capacities practically equally share the remaining half of total installed capacity. All of these data are presented below (Table 75 and Figure 271).

Table 75: Installed capacities per technology in 2030 – EMS market area

Technology	Installed capacity (MW)	
	2018	2030
Thermal - lignite	4092	4428
Thermal - gas	228	411
Hydro	3018	3031
Wind	201	2892/3615[6]
Solar	6	32/40[6]

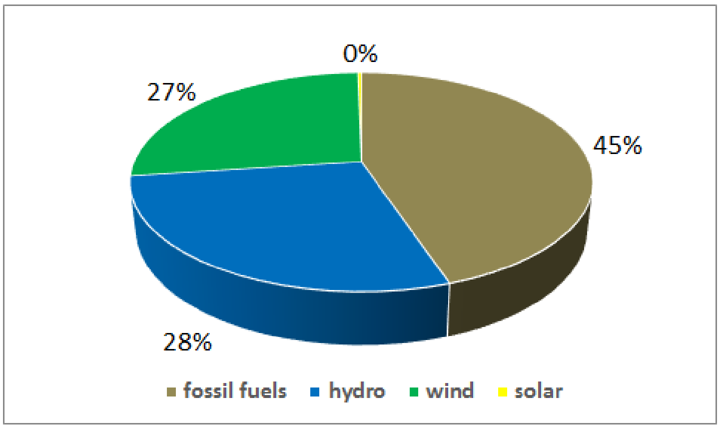


Figure 271: Installed capacity per fuel type in 2030 – EMS market area

The annual capacity factors for wind were provided by EMS within the questionnaire, and solar capacity factors were downloaded from a publicly available database[9], keeping in mind that capacity factors for the years 1982 and 1984 were replaced by values for 2013 and 2009 (Table 76).

Table 76: Average wind and solar capacity factors for 1982,1984 and 2007 – EMS market area

EMS market area – average wind and solar capacity factors			
Year	**1982**	**1984**	**2007**
Wind CF	21.11%	24.19%	21.72%
Solar CF	14.57%	14.22%	14.94%

Table 77 shows the generation of Run Of River and HPPs with reservoirs on an annual basis, concerning both dry and average hydrology. The TSO provided all of the figures below.

Table 77: Annual generation for all HPPs for dry and average hydrology – EMS market area

[9] https://www.renewables.ninja/

Annual generation (GWh)	Dry	Average
ROR	8169	9451
HPPs with reservoirs	718	613
Total	8887	10064

Table 78 contains data provided by the EMS, which will be used for modeling the PSHPP Bajina Basta in ANTARES software.

Table 78: PSHPP data – EMS market area

Name	Number of units	Pgen (MW)	Ppump (MW)	Efficiency
PSHPP Bajina Basta	2	307	280	75%

We assumed nominal output of the PSHPP Bajina Basta in pumping mode and corresponding efficiency, by using our internal database.

8.1.11. ELES market area

ELES market area – Demand

The ELES market area is one of the smaller ones in the region. The highest consumption is expected in the winter (December, January), while the lowest consumptions are expected in June and April.

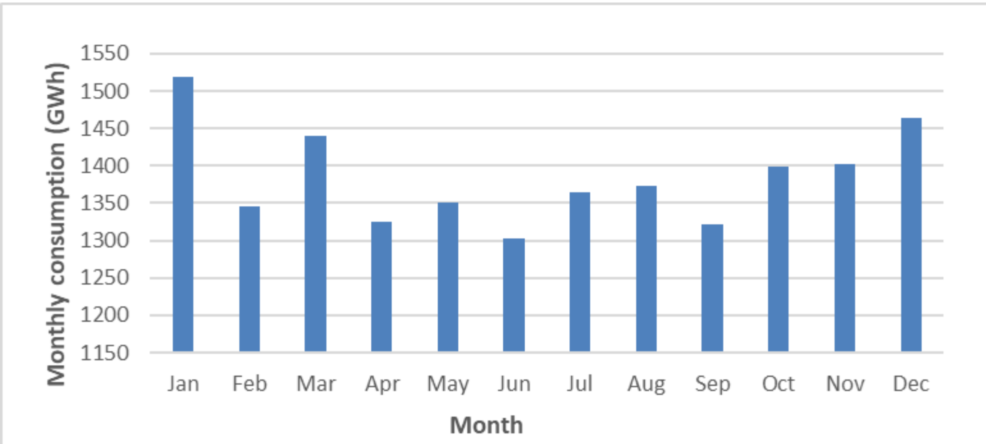


Figure 272: Monthly energy consumption (GWh) for 2030 – ELES market area

Total consumption in the Referent scenario is expected to reach 16.6 TWh, while in the low demand scenario, with a reduced growth rate, total annual consumption would be around 15.5 TWh (Table 79).

Table 79: Referent and low demand scenarios in 2030 – ELES market area

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)
SI	14.4	1.28%	16.61	0.64%	15.51

ELES market area – Production

For the ELES market area, we have confirmed that two new TPPs will be in operation in 2030 with additional generation capacity of 189 MW. Wind and solar power plants will grow to 10 MW and 492 MW, respectively. Table 80 provides data on the installed generation capacities in 2030 by technology.

Table 80: Installed capacities per technology in 2018 and 2030 – ELES market area

Technology	Installed capacity in 2018 (MW)	Installed capacity in 2030 (MW)
Thermal - lignite	1092	539
Thermal - gas	492	554
Thermal – hard coal	123	45
Nuclear	703	703
Hydro	1185	1334
Wind	3,3	10/150[6]
Solar	281	492/1650[6]

Regarding technologies, the largest share of installed power in the ELES market area will be in HPPs at level of 1,330 MW. TPPs will participate with approximately 31%. In 2030, 19% of the ELES market area's installed power will be in NPP Krško, jointly owned by Croatian HEP and Slovenian Gen-Energija. In the ELES market area, wind is expected to have a less important role than solar. Namely, there will be 492 MW in solar power and only 10 MW in wind power (14% and less than 0.1% share of installed power, respectively), as depicted in Figure 273.

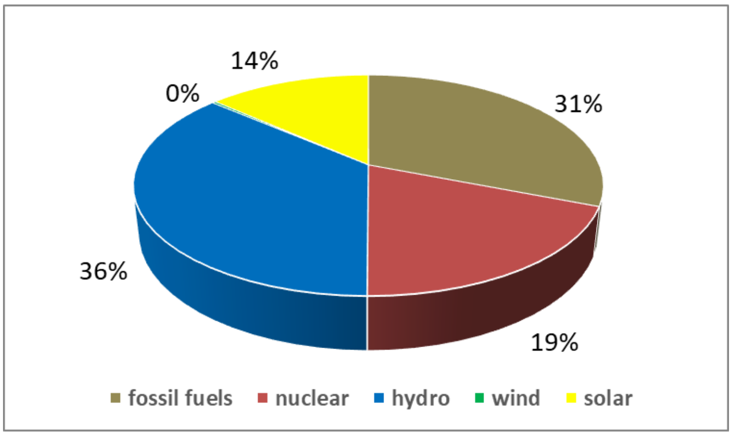


Figure 273: Installed capacity per fuel type in 2030 – ELES market area

Table 81 shows the average annual capacity factors for wind and solar plants, calculated on the basis of the time series provided by ELES.

Table 81: Adopted average wind and solar capacity factors for 1982, 1984 and 2007 – ELES market area

ELES market area – average wind and solar capacity factors			
Year	**1982**	**1984**	**2007**
Wind CF	23,06%	23,97%	22,01%
Solar CF	12,37%	11,99%	12,64%

ELES provided the hydro generation for average hydrology for all HPPs. However, dry hydrology generation was missing for certain HPPs. For these HPPs we estimated generation in dry hydrological conditions by multiplying generation in average hydrological conditions by a factor 0.77, which is in line with available data for other HPPs. All the HPPs are considered as Run of River (ROR) and their generation is given in Table 82.

Table 82: Annual generation for all HPPs for dry and average hydrology – ELES market area

Annual generation (GWh)	Dry	Average
ROR	3464	4494
HPPs with reservoirs	0	0
Total	3464	4494

Table 83 provides data for modeling PSHPPs in the ELES market area.

Table 83: PSHPP data – ELES market area

Name	Number of units	Pgen (MW)	Ppump (MW)	Efficiency
PSHPP Soča	1	185	180	75%

8.2. Network models

The following subchapters provide brief information on the national/TSO models collected for the EMI grid analyses, the engagement of the generation units for each country is a result of TSOs internal analyses.

8.2.1. OST models (AL)

In the year 2030, OST expects its transmission system to have 9 tie-lines at these voltage levels:

- 4 tie-lines of voltage level 400 kV
- 3 tie-lines of voltage level 220 kV
- 1 tie-line of voltage level 150 kV
- 1 tie-line of voltage level 110 kV

The elements used to model the power system of AL in 2030 are shown in *Table 84*.

Table 84: Number of elements in models of AL in 2030

333 BUSES	101 PLANTS	107 MACHINES	0 INDUCTION GENS	0 INDUCTION MOTORS
98 LOADS	0 FIXED SHUNTS	1 SWITCHED SHUNTS		
387 BRANCHES	148 TRANSFORMERS	0 DC LINES	0 FACTS DEVICES	0 GNE DEVICES

We show the expected installed generation capacities in the AL power system in 2030 in *Table 85*. This table shows the total maximum active power output; total rated apparent power; and the number of generation units. The data are given for each type of unit (fuel/technology type) and the last row shows the sum of all data in the corresponding column.

Table 85: Installed generation capacities in 2030 in the AL power system

Unit (fuel) type	Referent RES			High RES		
	Total P_{max} (MW)	Total S_n (MVA)	Number of units	Total P_{max} (MW)	Total S_n (MVA)	Number of units
CCGT OLD 2	100.00	117.64	1	100.00	117.64	1
CCGT NEW	200.00	235.30	2	200.00	235.30	2
Run-of-river (turbine)	772.02	881.22	115	772.02	881.22	115
Pump Storage Annual Reservoir (turbine)	2,108.54	2,448.27	34	2,108.54	2,448.27	34
Pump Storage & Storage / Weekly reservoir (turbine)	68.00	76.00	2	68.00	76.00	2
WIND ONSHORE	384.00	402.81	10	**480.00**	**503.67**	**12**
Solar (Photovoltaic)	445.40	455.16	9	**557.40**	**569.44**	**10**
Total	**4,077.96**	**4,616.40**	**173**	**4,285.96**	**4,831.54**	**176**

The right side of the table shows the data used for the High RES variant, and the differences compared to the Referent RES are shown in red. The high RES case includes two additional WPPs and one additional SPP.

We show the loading of branches in the AL transmission grid in *Figure 274*, for branches of voltage levels of 110 kV and above.

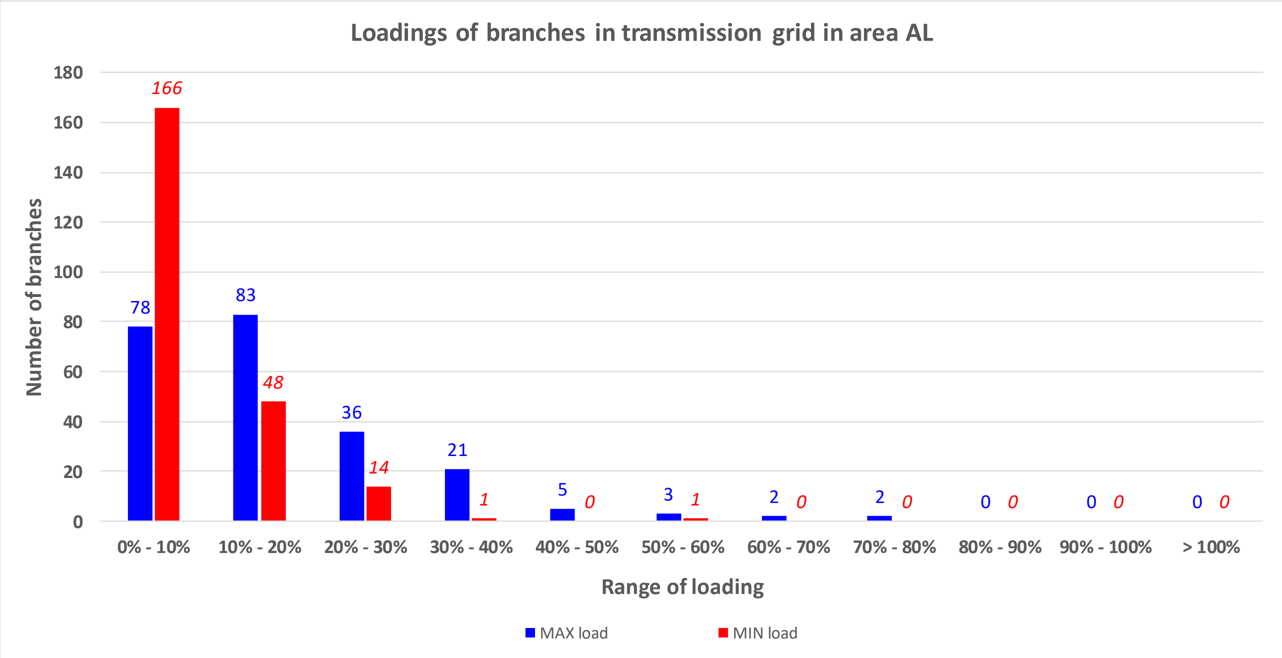


Figure 274: Histogram of branch loading in expected maximum and minimum regimes in 2030 in transmission grid of AL

From the figure, we see that there are no overloaded branches in the AL transmission grid, and that most elements are loaded below 20%. During the maximum load regime, there are 5 branches loaded over 50%, and two have loadings of 70% – 80%.

During the minimum load regime, almost all the elements have loadings below 30%. There is just one branch with a loading of 50% – 60%, and one branch with a loading of 30% – 40%.

Maximum load regime

We show the summary of area totals, as reported from PSS®E, for the maximum load 2030 regime in the Referent RES variant in *Table 86*. The first row represents data related to active power (in MW), while the second row shows data related to reactive power (in MVar).

Table 86: Area summary of AL power system in maximum load 2030 regime, variant Referent 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	TO TIES + LOADS	DESIRED NET INT
10	1149.3	0.0	0.0	1873.0	0.0	0.0	4.9	0.0	27.7	-756.3	-756.3	-757.0
AL	117.4	0.0	0.0	506.4	-51.4	0.0	29.5	674.3	330.6	-23.5	-23.5	

The total AL system load is 1.873 MW and 506,4 MVar, including auxiliary loads. The value of active power losses is around 32,6 MW, which is a relatively low share (1,74%) of total system active load. In this regime we expect that OST would import around 757 MW from neighboring systems.

It should be noted that counting of total losses include all lines and transformers in this power system, including step up transformers and transformers to distribution network (if any).

We show the AL system summary per voltage level in *Table 87*. For each voltage level, this table shows assigned total active and reactive power losses, as well as part of the losses that result from line shunts (i.e., transformer magnetizing losses). The last column shows the level of reactive power generated by line charging.

Table 87: Summary per voltage levels in the AL power system for maximum load in 2030, Referent RES

VOLTAGE LEVEL	BRANCHES	LOSSES MW	LOSSES MVAR	LINE SHUNTS MW	LINE SHUNTS MVAR	CHARGING MVAR
400.0	13	3.40	37.55	0.0	0.0	356.3
220.0	54	5.96	72.49	0.9	4.7	227.4
154.0	1	0.19	0.50	0.0	0.0	1.5
150.0	1	0.09	0.22	0.0	0.0	0.7
110.0	204	15.36	134.88	1.3	10.7	88.4
35.0	23	0.14	2.67	0.4	1.4	0.0
30.0	5	0.07	4.52	0.2	1.8	0.0
20.0	36	0.21	6.14	0.6	1.9	0.0
13.8	4	1.21	35.64	0.3	1.7	0.0
11.5	4	0.53	21.05	0.2	1.5	0.0
10.5	11	0.44	12.21	0.5	2.5	0.0
10.0	3	0.01	0.17	0.1	0.4	0.0
7.3	1	0.02	0.22	0.0	0.1	0.0
6.6	1	0.00	0.09	0.0	0.1	0.0
6.3	26	0.11	2.18	0.5	2.8	0.0
TOTAL	387	27.74	330.56	4.9	29.5	674.3

From this table it can be seen that most of the active power losses, 55,4% arise on the 110 kV system, while losses in the HV grid participate with 90,1% in total system losses.

We show the level of active power generation in the AL power system, in the maximum load regime for 2030, using Referent RES, in *Table 88*. This table shows data per unit type (fuel/technology type) as well as the sum of all the data in corresponding columns, for operating units. It should be noted that this data shows output from generation units (values on transmission level must be decreased by auxiliary loads and losses in step up transformers).

The data include total active power generation and total maximum available active power, so we can estimate the active power reserve. In addition, we show total rated apparent power, so we can also estimate reactive power levels. Finally, each row shows the number of units in operation, and those that are overloaded, if any.

Table 88: Active power generation in the AL power system, maximum load regime, for 2030, Referent RES Case

Fuel type	Total P_{gen} (MW)	Total P_{max} (MW)	Total S_n (MVA)	Number of units
CCGT OLD 2	80.00	100.00	117.64	1
CCGT NEW	160.00	200.00	235.30	2
Run-of-river (turbine)	214.83	641.18	731.21	84
Pump Storage Annual Reservoir (turbine)	482.48	636.00	735.19	6
Pump Storage & Storage / Weekly reservoir (turbi	9.72	34.00	38.00	1
WIND ONSHORE	110.28	270.00	282.68	6
Solar (Photovoltaic)	92.00	387.90	396.44	7
Total	**1,149.31**	**2,269.08**	**2,536.46**	**107**

This table shows that in the maximum load regime, there are 107 units in operation.

In the High RES scenario, a different generation pattern is defined. Generation per fuel type is shown in *Table 89*. The differences are significant, in comparison to the Referent RES scenario.

Table 89: Active power generation in the AL power system, maximum load regime, for 2030, High RES Case

Fuel type	Total P_{gen} (MW)	Total P_{max} (MW)	Total S_n (MVA)	Number of units
CCGT OLD 2	80.00	100.00	117.64	1
CCGT NEW	160.00	200.00	235.30	2
Run-of-river (turbine)	209.08	633.07	721.11	81
Pump Storage Annual Reservoir (turbine)	323.45	436.00	506.39	4
Pump Storage & Storage / Weekly reservoir (turbi	9.72	34.00	38.00	1
WIND ONSHORE	178.00	446.00	467.59	11
Solar (Photovoltaic)	184.70	462.40	472.50	8
Total	**1,144.95**	**2,311.47**	**2,558.53**	**108**

As result of this different generation pattern, the total values related to this area do not change. The summary of area totals, as reported from PSS®E, is shown in Table 90.

Table 90: Area summary of AL power system in maximum load 2030 regime, variant High RES

X-- AREA --X	FROM GENE-RATION	AT AREA BUSES: FROM IND GENERATN	AT AREA BUSES: TO IND MOTORS	AT AREA BUSES: 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	1144.9	0.0	0.0	1873.0	0.0	0.0	4.7	0.0	24.0	-756.8	-756.8	-757.0
AL	162.9	0.0	0.0	506.4	-51.0	0.0	28.7	666.1	308.9	36.0	36.0	

Due to a different generation pattern, the value of active power losses is changed to 28,7 MW compared to 32,6 MW in the referent RES scenario.

Minimum load regime

We show a summary of area totals, as reported from PSS®E, for the minimum load 2030 regime in the Referent RES case in Table 91. The first row represents data related to active power (in MW), while the second row shows data related to reactive power (in MVar).

Table 91: Area summary of AL power system in minimum load 2030 regime, variant Referent RES

X-- AREA --X	FROM GENE-RATION	AT AREA BUSES: FROM IND GENERATN	AT AREA BUSES: TO IND MOTORS	AT AREA BUSES: 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	708.6	0.0	0.0	560.7	0.0	0.0	4.7	0.0	13.3	129.9	129.9	130.0
AL	107.2	0.0	0.0	158.5	488.9	0.0	29.0	662.9	150.6	-57.0	-57.0	

The total AL system load is 560,7 MW and 158,5 MVar, including auxiliary loads, so the total system active load is 29,9% of the maximum load. Value of active power losses is around 18 MW, which is around 3,21% of the total system active load. In this regime, we would expect OST to export around 130 MW to the neighboring systems.

It should be noted that counting of total losses include all lines and transformers in this power system, including step up transformers and transformers to distribution network (if any).

We show the AL system summary for each voltage level in Table 92, including the total active and reactive power losses, and the share of losses from line shunts (i.e., transformer magnetizing losses). The final column shows the reactive power generated by line chargings.

Table 92: Summary per voltage levels in power system of AL for minimum load 2030, variant with Referent RES

```
VOLTAGE        X----- LOSSES -----X    X-- LINE  SHUNTS --X    CHARGING
LEVEL  BRANCHES        MW          MVAR          MW           MVAR          MVAR
400.0       13        4.90        54.08         0.0           0.0         339.8
220.0       54        3.24        25.39         0.8           4.5         229.8
154.0        1        0.08         0.21         0.0           0.0           1.5
150.0        1        0.04         0.10         0.0           0.0           0.7
110.0      204        3.15        16.82         1.3          10.8          91.0
 35.0       23        0.03         0.77         0.4           1.5           0.0
 30.0        5        0.15         8.86         0.2           1.8           0.0
 20.0       36        0.23         6.98         0.6           1.9           0.0
 13.8        3        0.72        19.65         0.2           1.3           0.0
 11.5        4        0.22         8.87         0.2           1.4           0.0
 10.5       10        0.18         3.83         0.4           2.3           0.0
 10.0        3        0.00         0.00         0.1           0.4           0.0
  7.3        1        0.00         0.05         0.0           0.1           0.0
  6.6        1        0.00         0.00         0.0           0.1           0.0
  6.3       26        0.32         4.98         0.5           2.9           0.0
TOTAL      385       13.25       150.60         4.7          29.0         662.9
```

From this table it can be seen that the most part of active power losses 23,8% is allocated in 110 kV, while losses in HV grid participate with 86,1% in total system losses.

We show active power generation in the AL power system, in the minimum load regime for 2030, Referent RES case, in *Table 93*. This table shows the data per unit type (fuel/technology type) as well as the sum of all data in corresponding columns, for units in operation. This data shows the output from generation units (values on the transmission level must be decreased by auxiliary loads and losses in step-up transformers).

The data include total active power generation and total maximum available active power, so we can estimate active power reserve. In addition, we show the total rated apparent power, and can thus estimate reactive power possibilities. Finally, each row contains the number of units in operation.

Table 93: Active power generation in AL power system, minimum load regime, year 2030, Referent RES Case

Fuel type	Total P_{gen} (MW)	Total P_{max} (MW)	Total S_n (MVA)	Number of units
CCGT OLD 2	0.00	0.00	0.00	0
CCGT NEW	90.00	100.00	117.65	1
Run-of-river (turbine)	124.90	199.17	228.52	27
Pump Storage Annual Reservoir (turbine)	299.72	407.67	464.80	8
Pump Storage & Storage / Weekly reservoir (turbi	0.00	0.00	0.00	0
WIND ONSHORE	162.00	300.00	314.10	8
Solar (Photovoltaic)	32.00	330.00	337.36	5
Total	**708.62**	**1,336.84**	**1,462.43**	**49**

We see that in the minimum load regime, there are 49 units in operation.

In case of High RES scenario, different generation pattern is defined. Generation per fuel type is shown in *Table 94*. From the table it can be seen that differences are significant, in comparison against Referent RES scenario.

Table 94: Active power generation in AL power system, minimum load regime, year 2030, High RES Case

Fuel type	Total P_{gen} (MW)	Total P_{max} (MW)	Total S_n (MVA)	Number of units
CCGT OLD 2	0.00	0.00	0.00	0
CCGT NEW	90.00	100.00	117.65	1
Run-of-river (turbine)	124.90	199.17	228.52	27
Pump Storage Annual Reservoir (turbine)	234.80	407.67	464.80	8
Pump Storage & Storage / Weekly reservoir (turbi	0.00	0.00	0.00	0
WIND ONSHORE	197.00	396.00	414.96	10
Solar (Photovoltaic)	62.00	330.00	337.36	5
Total	**708.70**	**1,432.84**	**1,563.29**	**51**

As result of this different generation pattern, total values related to this area are not changed. Summary of area totals, as report from PSS®E, in shown in *Table 95*.

Table 95: Area summary of AL power system in minimum load 2030 regime, variant Referent 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	708.7	0.0	0.0	560.7	0.0	0.0	4.8	0.0	13.3	129.9	129.9	130.0
AL	100.5	0.0	0.0	158.5	496.0	0.0	29.3	666.6	142.6	-59.4	-59.4	

8.2.2. NOS BiH models (BA)

In the year 2030, NOS BiH expects its transmission system to have 41 tie-lines at these voltage levels:

- 6 tie-lines of voltage level 400 kV
- 14 tie-lines of voltage level 220 kV
- 21 tie-line of voltage level 110 kV

The elements used to model the power system of BA in 2030 are shown in *Table 96*.

Table 96: Number of elements in models of BA in 2030

893 BUSES	63 PLANTS	42 MACHINES	0 INDUCTION GENS	0 INDUCTION MOTORS
187 LOADS	0 FIXED SHUNTS	0 SWITCHED SHUNTS		
828 BRANCHES	384 TRANSFORMERS	0 DC LINES	0 FACTS DEVICES	0 GNE DEVICES

We show the expected installed generation capacities in the BA power system in 2030 in **Table 97**. This table shows the total maximum active power output; total rated apparent power; and the number of generation units. The data are given for each type of unit (fuel/technology type) and the last row shows the sum of all data in the corresponding column.

Table 97: Installed generation capacities in 2030 in the BA power system

Unit (fuel) type	Referent RES			High RES		
	Total P_{max} (MW)	Total S_n (MVA)	Number of units	Total P_{max} (MW)	Total S_n (MVA)	Number of units
Lignite old 1	1,773.00	2,102.90	9	1,773.00	2,102.90	9
LIGNITE NEW	1,050.00	1,186.00	3	1,050.00	1,186.00	3
Run-of-river (turbine)	1,196.90	1,349.10	32	1,196.90	1,349.10	32
Pump Storage Annual Reservoir (turbine)	516.00	586.00	11	516.00	586.00	11
Pump Storage / Daily reservoir (pump)	-420.00	480.00	2	-420.00	480.00	2
Pump Storage / Daily reservoir (turbine)	545.00	600.00	5	545.00	600.00	5
Pump Storage & Storage / Weekly reservoir (turbi	230.00	250.00	3	230.00	250.00	3
WIND ONSHORE	579.60	835.60	11	**649.60**	**895.60**	11
Solar (Photovoltaic)	100.00	200.00	2	**200.00**	**300.00**	2
Total	**5,570.50**	**7,589.60**	**78**	**5,740.50**	**7,749.60**	**78**

The right side of the table shows the data used for the High RES variant, and the differences compared to the Referent RES are shown in red. It can be seen that the variant with High RES does not include additional units of WPP or SPP, only additional installed capacity.

We show the loading of branches in the BA transmission grid in *Figure 275*, for branches of voltage levels of 110 kV and above.

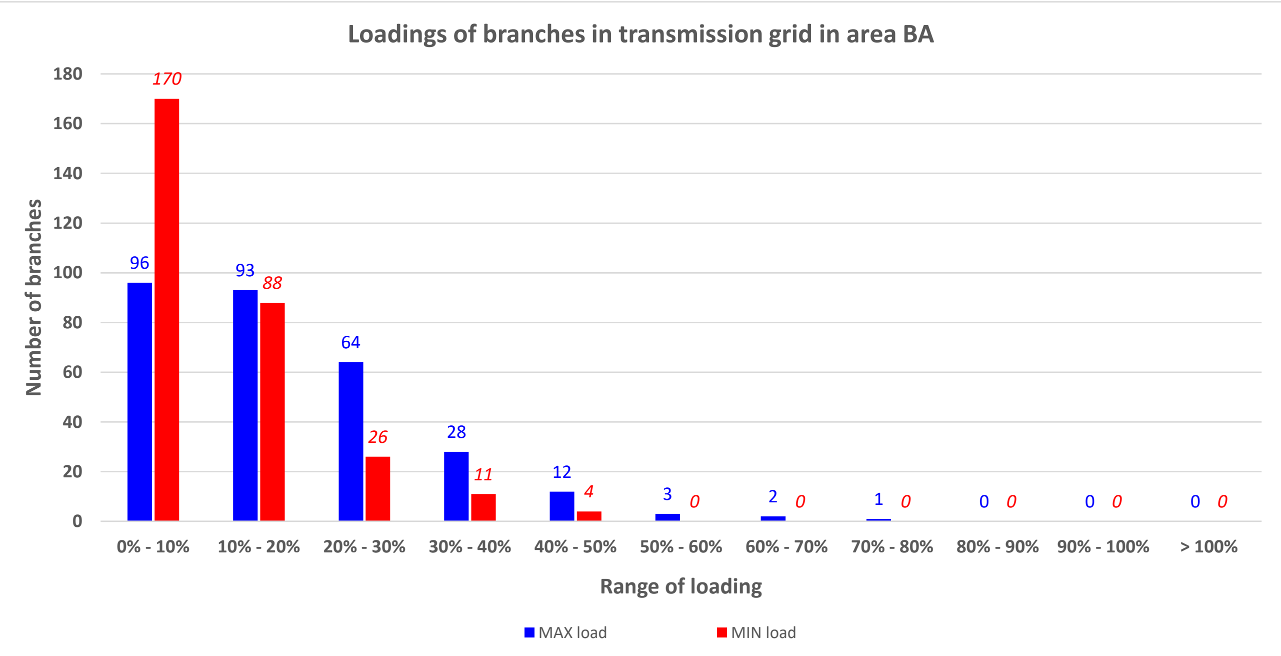


Figure 275: Histogram of branch loading in expected maximum and minimum regimes in 2030 in transmission grid of BA

From the figure, we see that there are no overloaded branches in the BA transmission grid, and that most elements are loaded below 30%.During the maximum load regime, there are 6 branches loaded over 50%, and one have loading of 70% – 80%.

During the minimum load regime, almost all the elements have loadings below 40%. There are just four branches with loadings of 40% – 50%.

Maximum load regime

We show the summary of area totals, as reported from PSS®E, for the maximum load 2030 regime in the Referent RES variant in *Table 98*. The first row represents data related to active power (in MW), while the second row shows data related to reactive power (in MVar).

Table 98: Area summary of BA power system in maximum load 2030 regime, variant Referent RES

X-- AREA --X	FROM GENE-RATION (AT AREA BUSES)	FROM IND GENERATN (AT AREA BUSES)	TO IND MOTORS (AT AREA BUSES)	TO LOAD (AT AREA BUSES)	TO BUS SHUNT	TO GNE BUS DEVICES	TO LINE SHUNT	FROM CHARGING	TO LOSSES	NET INTERCHANGE TO TIE LINES	NET INTERCHANGE TO TIES + LOADS	DESIRED NET INT
13	3178.7	0.0	0.0	2328.0	0.0	0.0	15.8	0.0	64.9	770.0	783.5	770.0
BA	554.3	0.0	0.0	458.4	0.0	0.0	160.9	1056.2	737.0	254.2	246.8	

The total BA system load is 2.328 MW and 458,4 MVar, including auxiliary loads. The value of active power losses is around 80,7MW, which is relatively around 3,47%, in comparison against total system active load. In this regime it is expected that NOS BiH exports around 770 MW to neighboring systems.

It should be noted that counting of total losses include all lines and transformers in this power system, including step up transformers and transformers to distribution network (if any).

We show the BA system summary per voltage level in *Table 99*. For each voltage level this table shows assigned total active and reactive power losses as well as part of this losses which resulted from line shunts (i.e. transformer magnetizing losses). Last column shows reactive power generated by line chargings.

Table 99: Summary per voltage levels in the BA power system for maximum load 2030, variant with Referent RES

VOLTAGE LEVEL	BRANCHES	LOSSES MW	LOSSES MVAR	LINE SHUNTS MW	LINE SHUNTS MVAR	CHARGING MVAR
400.0	19	8.05	81.67	0.0	0.0	621.0
220.0	49	10.56	68.89	0.7	9.1	261.0
110.0	292	32.87	180.44	2.6	26.3	174.0
42.0	9	0.02	0.85	0.1	1.5	0.0
35.0	189	2.33	44.65	3.9	38.7	0.1
30.0	3	0.17	3.67	0.0	0.0	0.0
22.0	3	1.99	95.16	0.8	8.2	0.0
20.0	60	3.13	90.58	2.0	19.7	0.0
15.8	5	0.70	33.41	0.8	8.5	0.0
15.7	2	0.00	0.00	0.3	2.6	0.0
15.6	2	0.47	16.83	0.2	1.7	0.0
14.4	3	0.44	17.89	0.3	2.5	0.0
13.8	5	0.16	5.71	0.4	4.3	0.0
10.5	18	0.85	21.61	0.5	4.3	0.0
10.0	156	2.77	57.94	2.9	31.5	0.0
6.3	9	0.44	17.67	0.1	1.4	0.0
6.0	4	0.00	0.00	0.1	0.7	0.0
TOTAL	828	64.93	736.97	15.8	160.9	1056.2

From this table it can be seen that the most part of active power losses 50,6% is allocated in 110 kV, while losses in HV grid participate with 79,3% in total system losses.

We show the level of active power generation in the BA power system, in the maximum load regime for 2030, using Referent RES, in *Table 100*. This table shows data per unit type (fuel/technology type) as well as the sum of all the data in corresponding columns, for operating units. It should be noted that this data shows output from generation units (values on transmission level must be decreased by auxiliary loads and losses in step up transformers).

The data include total active power generation and total maximum available active power, so we can estimate the active power reserve. In addition, we show total rated apparent power, so we can also estimate reactive power levels. Finally, each row shows the number of units in operation, and those that are overloaded.

Table 100: Active power generation in BA power system, maximum load regime, for 2030, Referent RES Case

Fuel type	Total P_{gen} (MW)	Total P_{max} (MW)	Total S_n (MVA)	Number of units
Lignite old 1	744.68	830.00	976.50	3
LIGNITE NEW	1,030.00	1,050.00	1,186.00	3
Run-of-river (turbine)	451.00	589.90	666.50	14
Pump Storage Annual Reservoir (turbine)	366.00	368.50	420.00	8
Pump Storage / Daily reservoir (pump)	0.00	0.00	0.00	0
Pump Storage / Daily reservoir (turbine)	40.00	45.00	50.00	1
Pump Storage & Storage / Weekly reservoir (turbi	160.00	175.00	185.00	2
WIND ONSHORE	387.00	579.60	835.60	11
Solar (Photovoltaic)	0.00	0.00	0.00	0
Total	**3,178.68**	**3,638.00**	**4,319.60**	**42**

This table shows that in the maximum load regime, there are 42 units in operation.

In case of High RES scenario, generation pattern is the same as in Referent RES scenario, so the only difference in models is in installed capacities of additional RES.

Minimum load regime

We show a summary of area totals, as reported from PSS®E, for the minimum load 2030 regime in the Referent RES case in *Table 101*. The first row represents data related to active power (in MW), while the second row shows data related to reactive power (in MVar).

Table 101: Area summary of BA power system in minimum load 2030 regime, variant Referent RES

```
                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

  13           1558.1      0.0      0.0   1105.0      0.0      0.0     16.2       0.0      37.0    399.9    416.6    400.0
BA              153.3      0.0      0.0    232.3      0.0      0.0    165.2    1071.7     374.0    453.6    445.5
```

The total BA system load is 1.105 MW and 232,3 MVar, including auxiliary loads, so the total system active load is 47,5% of the maximum load. Value of active power losses is around 53,2 MW, which is around 4,81%, of the total system active load. In this regime we would expect NOS BiH to export 400 MW to the neighboring systems.

It should be noted that counting of total losses include all lines and transformers in this power system, including step up transformers and transformers to distribution network (if any).

We show the BA system summary for each voltage level in *Table 102*, including the total active and reactive power losses, and the share of losses from line shunts (i.e., transformer magnetizing losses). The final column shows the reactive power generated by line chargings.

Table 102: Summary per voltage levels in the BA power system for minimum load 2030, variant with Referent RES

VOLTAGE LEVEL	BRANCHES	LOSSES MW	LOSSES MVAR	LINE SHUNTS MW	LINE SHUNTS MVAR	CHARGING MVAR
400.0	19	10.26	104.04	0.0	0.0	627.2
220.0	49	7.60	52.25	0.8	9.2	263.8
110.0	292	15.43	76.99	2.7	26.8	180.5
42.0	9	0.02	0.85	0.1	1.5	0.0
35.0	189	0.45	8.68	4.1	40.3	0.1
30.0	3	0.14	3.03	0.0	0.0	0.0
22.0	3	1.67	80.45	0.8	8.4	0.0
20.0	60	0.83	29.85	2.0	20.1	0.0
15.8	5	0.05	3.53	0.8	8.7	0.0
15.7	2	0.00	0.00	0.3	2.6	0.0
15.6	2	0.00	0.00	0.2	1.7	0.0
14.4	3	0.00	0.00	0.3	2.4	0.0
13.8	5	0.00	0.00	0.4	4.4	0.0
10.5	18	0.00	0.00	0.5	4.3	0.0
10.0	156	0.51	10.68	3.1	32.8	0.0
6.3	9	0.08	3.60	0.1	1.4	0.0
6.0	4	0.00	0.00	0.1	0.7	0.0
TOTAL	828	37.03	373.95	16.2	165.2	1071.7

From this table it can be seen that the most part of active power losses 41,7% is allocated in 110 kV, while losses in HV grid participate with 89,9% in total system losses.

We show active power generation in the BA power system, in the minimum load regime for 2030, Referent RES case, in *Table 103*. This table shows the data per unit type (fuel/technology type) as well as the sum of all data in corresponding columns, for units in operation. This data shows the output from generation units (values on the transmission level must be decreased by auxiliary loads and losses in step-up transformers).

The data include total active power generation and total maximum available active power, so we can estimate active power reserve. In addition, we show the total rated apparent power, and can thus estimate reactive power possibilities. Finally, each row contains the number of units in operation.

Table 103: Active power generation in BA power system, minimum load regime, year 2030, Referent RES Case

Fuel type	Total P_{gen} (MW)	Total P_{max} (MW)	Total S_n (MVA)	Number of units
Lignite old 1	243.14	300.00	353.00	1
LIGNITE NEW	960.00	1,050.00	1,186.00	3
Run-of-river (turbine)	100.00	105.00	115.00	1
Pump Storage Annual Reservoir (turbine)	30.00	30.50	36.00	1
Pump Storage / Daily reservoir (pump)	0.00	0.00	0.00	0
Pump Storage / Daily reservoir (turbine)	0.00	0.00	0.00	0
Pump Storage & Storage / Weekly reservoir (turbi	0.00	0.00	0.00	0
WIND ONSHORE	225.00	579.60	835.60	11
Solar (Photovoltaic)	0.00	0.00	0.00	0
Total	**1,558.14**	**2,065.10**	**2,525.60**	**17**

We see that in the minimum load regime, there are 17 units in operation.

In case of High RES scenario, generation pattern is the same as in Referent RES scenario, so the only difference in models is in installed capacities of additional RES.

8.2.3. ESO models (BG)

In the year 2030, ESO expects its transmission system to have 10 tie-lines at 400kV voltage level.

The elements used to model the power system of BG in 2030 are shown in *Table 104*.

Table 104: Number of elements in models of BG in 2030

```
 839 BUSES        165 PLANTS          90 MACHINES       0 INDUCTION GENS       0 INDUCTION MOTORS
 932 LOADS          4 FIXED SHUNTS     0 SWITCHED SHUNTS
1061 BRANCHES     235 TRANSFORMERS     0 DC LINES         0 FACTS DEVICES        0 GNE DEVICES
```

We show the expected installed generation capacities in the BG power system in 2030 in *Table 105*. This table shows the total maximum active power output; total rated apparent power; and the number of generation units. The data are given for each type of unit (fuel/technology type) and the last row shows the sum of all data in the corresponding column.

Table 105: Installed generation capacities in 2030 in the BG power system

Unit (fuel) type	Referent RES			High RES		
	Total P_{max} (MW)	Total S_n (MVA)	Number of units	Total P_{max} (MW)	Total S_n (MVA)	Number of units
NUCLEAR	2,200.00	2,440.00	2	2,200.00	2,440.00	2
Lignite old 1	1,822.00	2,114.00	8	1,822.00	2,114.00	8
Lignite old 2	686.00	872.00	2	686.00	872.00	2
Hard Coal old 1	286.00	980.00	8	286.00	980.00	8
Conventional gas old 1	1,596.80	2,204.89	23	1,596.80	2,204.89	23
CCGT NEW	750.00	912.93	6	750.00	912.93	6
OCGT NEW	20.70	20.74	1	20.70	20.74	1
Run-of-river (turbine)	152.73	193.51	25	152.73	193.51	25
Pump Storage Annual Reservoir (turbine)	1,331.90	1,678.09	53	1,331.90	1,678.09	53
Pump Storage / Daily reservoir (pump)	-140.70	216.00	3	-140.70	216.00	3
Pump Storage / Daily reservoir (turbine)	510.00	615.00	9	510.00	615.00	9
Pump Storage & Storage / Weekly reservoir (pum	-784.00	940.00	4	-784.00	940.00	4
Pump Storage & Storage / Weekly reservoir (turbi	840.00	940.00	4	840.00	940.00	4
WIND ONSHORE	886.77	1,640.10	16	**1,108.77**	1,640.10	16
Solar (Photovoltaic)	2,942.90	2,847.90	63	**3,578.90**	**3,827.90**	**65**
Others renewable	12.00	10.00	1	12.00	10.00	1
Total	**13,113.10**	**18,625.16**	**228**	**13,971.10**	**19,605.16**	**230**

The right side of the table shows the data used for the High RES variant, and the differences compared to the Referent RES are shown in red. It can be seen that the variant with High RES includes one additional WPPs and six additional SPP.

We show the loading of branches in the BG transmission grid in *Figure 276*, for branches of voltage levels of 110 kV and above.

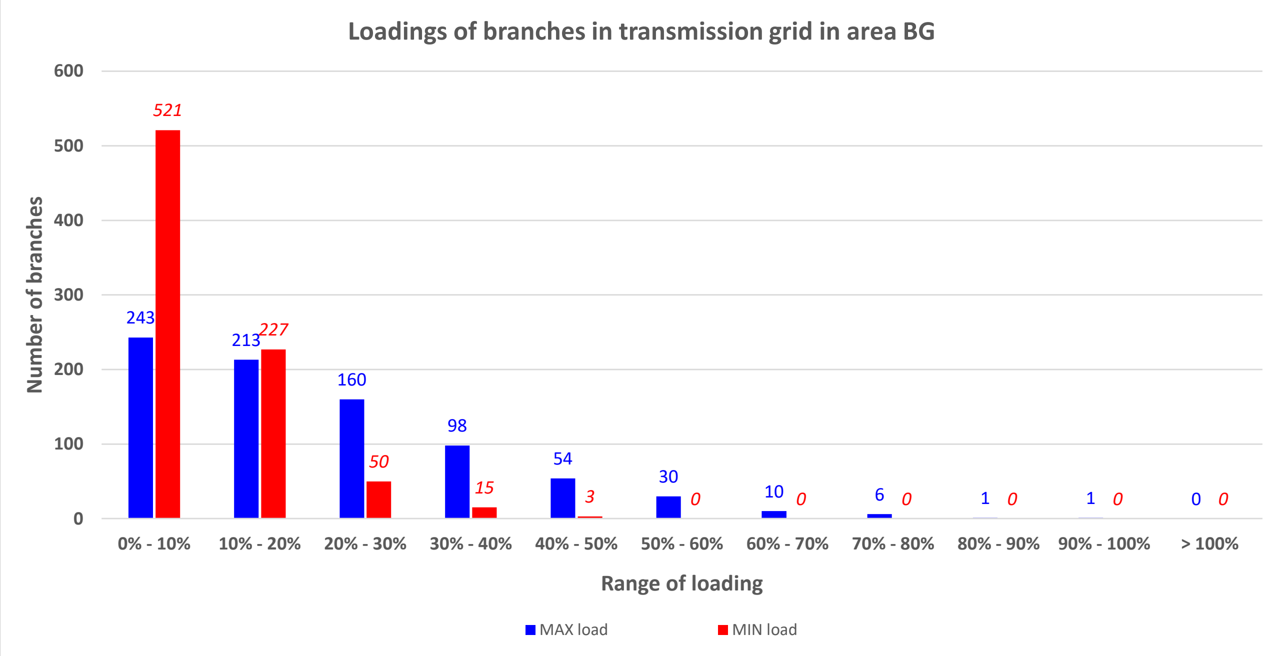


Figure 276: Histogram of branch loading in expected maximum and minimum regimes in 2030 in transmission grid of BG

From the figure, we see that there are no overloaded branches in the BG transmission grid, and that most elements are loaded below 40%. During the maximum load regime, there are 8 branches loaded over 70%, one having a loading of 90% – 100%.

During the minimum load regime, almost all the elements have loadings below 40%. There are just three branches with a loading of 40% – 50%.

Maximum load regime

We show the summary of area totals, as reported from PSS®E, for the maximum load 2030 regime in the Referent RES variant in *Table 106*. The first row represents data related to active power (in MW), while the second row shows data related to reactive power (in MVar).

Table 106: Area summary of BG power system in maximum load 2030 regime, variant Referent RES

X-- AREA --X	FROM GENE-RATION (AT AREA BUSES)	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
14	7188.3	0.0	0.0	6982.3	0.0	0.0	61.0	0.0	145.0	0.0	0.0	0.0
BG	2113.0	0.0	0.0	2763.8	85.1	0.0	169.9	2826.5	1920.7	0.0	0.0	

The total BG system load is 6.982,3 MW and 2.763,8 MVar, including auxiliary loads. The value of active power losses is around 206 MW, which is relatively around 2,95%, in comparison against total system active load. In this regime it is expected that ESO exchanges zero with neighboring systems.

It should be noted that counting of total losses include all lines and transformers in this power system, including step up transformers and transformers to distribution network (if any).

We show the BG system summary per voltage level in *Table 107*. For each voltage level this table shows assigned total active and reactive power losses as well as part of this losses which resulted from line shunts (i.e. transformer magnetizing losses). Last column shows reactive power generated by line chargings.

Table 107: Summary per voltage levels in the BG power system for maximum load 2030, variant with Referent RES

VOLTAGE LEVEL	BRANCHES	LOSSES MW	LOSSES MVAR	LINE SHUNTS MW	LINE SHUNTS MVAR	CHARGING MVAR
400.0	37	23.30	245.06	44.3	0.0	1639.9
380.0	10	0.05	0.56	1.2	0.0	371.6
220.0	65	30.45	241.77	1.1	39.6	385.0
110.0	776	78.08	653.07	6.0	51.7	430.0
24.0	2	3.12	247.72	1.9	14.4	0.0
21.0	19	0.00	0.00	0.0	0.0	0.0
20.0	3	0.75	50.09	0.5	2.7	0.0
19.0	2	0.07	11.89	0.3	6.2	0.0
18.0	4	2.72	75.58	0.5	6.8	0.0
15.8	1	0.88	24.82	0.2	1.8	0.0
15.8	12	2.11	199.90	2.0	14.6	0.0
13.8	6	0.22	18.61	0.0	3.9	0.0
11.5	1	0.11	2.69	0.0	0.1	0.0
10.5	55	2.81	111.88	2.0	9.3	0.0
6.3	67	0.33	37.01	1.1	18.3	0.0
5.0	1	0.00	0.08	0.0	0.4	0.0
TOTAL	1061	144.99	1920.74	61.0	169.9	2826.5

From this table it can be seen that the most part of active power losses 53,9% is allocated in 110 kV, while losses in HV grid participate with 91% in total system losses.

We show the level of active power generation in the BG power system, in the maximum load regime for 2030, using Referent RES, *Table 108*. This table shows data per unit type (fuel/technology type) as well as the sum of all the data in corresponding columns, for operating units. It should be noted that this data shows output from generation units (values on transmission level must be decreased by auxiliary loads and losses in step up transformers).

The data include total active power generation and total maximum available active power, so we can estimate the active power reserve. In addition, we show total rated apparent power, so we can also estimate reactive power levels. Finally, each row shows the number of units in operation, and those that are overloaded.

Table 108: Active power generation in BG power system, maximum load regime, for 2030, Referent RES Case

Fuel type	Total P_{gen} (MW)	Total P_{max} (MW)	Total S_n (MVA)	Number of units
NUCLEAR	2,139.09	2,200.00	2,440.00	2
Lignite old 1	1,767.25	1,822.00	2,114.00	8
Lignite old 2	541.18	686.00	872.00	2
Hard Coal old 1	59.97	60.00	78.75	1
Conventional gas old 1	569.75	670.80	820.39	13
CCGT NEW	727.69	750.00	912.93	6
OCGT NEW	0.00	0.00	0.00	0
Run-of-river (turbine)	47.84	61.05	75.78	12
Pump Storage Annual Reservoir (turbine)	681.62	778.10	961.09	26
Pump Storage / Daily reservoir (pump)	0.00	0.00	0.00	0
Pump Storage / Daily reservoir (turbine)	218.90	250.00	299.00	4
Pump Storage & Storage / Weekly reservoir (pum	0.00	0.00	0.00	0
Pump Storage & Storage / Weekly reservoir (turbi	200.00	210.00	235.00	1
WIND ONSHORE	235.24	662.77	1,140.10	15
Solar (Photovoltaic)	0.00	0.00	0.00	0
Others renewable	0.00	0.00	0.00	0
Total	**7,188.53**	**8,150.72**	**9,949.04**	**90**

This table shows that in the maximum load regime, there are 90 units in operation.

In case of High RES scenario, generation pattern is the same as in Referent RES scenario, so the only difference in models is in installed capacities of additional RES.

Minimum load regime

We show a summary of area totals, as reported from PSS®E, for the minimum load 2030 regime in the Referent RES case in Table 109. The first row represents data related to active power (in MW), while the second row shows data related to reactive power (in MVar).

Table 109: Area summary of BG power system in minimum load 2030 regime, variant Referent RES

```
                 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

    14          3236.6       0.0       0.0   3142.3       0.6      0.0     63.5       0.0      30.3      0.0      0.0      0.0
  BG             319.2       0.0       0.0   1243.8    1328.5      0.0    177.9    2970.5     539.4      0.0      0.0
```

The total BG system load is 3.142,3 MW and 1.243,8 MVar, including auxiliary loads, so the total system active load is 45% of the maximum load. Value of active power losses is around 93,8 MW, which is around 2,98% of the total system active load. In this regime we would expect ESO to exchange zero with the neighboring systems.

It should be noted that counting of total losses includes all lines and transformers in this power system, including step up transformers and transformers to the distribution network (if any).

We show the BG system summary for each voltage level in *Table 110*, including the total active and reactive power losses, and the share of losses from line shunts (i.e., transformer magnetizing losses). The final column shows the reactive power generated by line chargings.

Table 110: Summary per voltage levels in the BG power system for minimum load 2030, variant with Referent RES

VOLTAGE LEVEL	BRANCHES	X----- LOSSES -----X MW	MVAR	X-- LINE SHUNTS --X MW	MVAR	CHARGING MVAR
400.0	37	6.33	65.07	46.0	0.0	1704.8
380.0	10	0.05	0.59	1.2	0.0	385.8
220.0	65	6.85	64.70	1.1	41.0	405.0
110.0	776	13.74	137.51	6.4	54.4	474.8
24.0	2	1.55	122.81	1.9	14.8	0.0
21.0	19	0.00	0.00	0.0	0.0	0.0
20.0	3	0.28	18.45	0.5	2.7	0.0
19.0	2	0.08	13.72	0.3	6.3	0.0
18.0	4	0.06	1.68	0.5	7.0	0.0
15.8	1	0.00	0.00	0.2	1.9	0.0
15.8	12	0.92	84.88	2.0	15.1	0.0
13.8	6	0.16	6.46	0.0	4.3	0.0
11.5	1	0.07	1.64	0.0	0.1	0.0
10.5	55	0.06	12.81	2.1	9.6	0.0
6.3	67	0.10	9.03	1.2	20.4	0.0
5.0	1	0.00	0.06	0.0	0.4	0.0
TOTAL	1061	30.25	539.41	63.5	177.9	2970.5

From this table it can be seen that the most part of active power losses 45,4% is allocated in 110 kV, while losses in HV grid participate with 89,2% in total system losses.

We show active power generation in the BG power system, in the minimum load regime for 2030, Referent RES case, in *Table 111*. This table shows the data per unit type (fuel/technology type) as well as the sum of all data in corresponding columns, for units in operation. This data shows the output from generation units (values on the transmission level must be decreased by auxiliary loads and losses in step-up transformers).

The data include total active power generation and total maximum available active power, so we can estimate active power reserve. In addition, we show the total rated apparent power, and can thus estimate reactive power possibilities. Finally, each row contains the number of units in operation.

Table 111: Active power generation in BG power system, minimum load regime, year 2030, Referent RES Case

Fuel type	Total P_{gen} (MW)	Total P_{max} (MW)	Total S_n (MVA)	Number of units
NUCLEAR	1,070.00	1,100.00	1,220.00	1
Lignite old 1	1,140.03	1,592.00	1,844.00	7
Lignite old 2	342.11	686.00	872.00	2
Hard Coal old 1	20.00	60.00	78.75	1
Conventional gas old 1	132.48	222.00	281.00	6
CCGT NEW	65.99	94.00	268.73	2
OCGT NEW	0.00	0.00	0.00	0
Run-of-river (turbine)	33.43	46.25	55.68	9
Pump Storage Annual Reservoir (turbine)	70.17	82.50	103.00	4
Pump Storage / Daily reservoir (pump)	0.00	0.00	0.00	0
Pump Storage / Daily reservoir (turbine)	0.00	0.00	0.00	0
Pump Storage & Storage / Weekly reservoir (pum	0.00	0.00	0.00	0
Pump Storage & Storage / Weekly reservoir (turbi	200.00	630.00	705.00	3
WIND ONSHORE	162.59	662.77	1,140.10	15
Solar (Photovoltaic)	0.00	0.00	0.00	0
Others renewable	0.00	0.00	0.00	0
Total	**3,236.80**	**5,175.52**	**6,568.26**	**50**

We see that in the minimum load regime, there are 50 units in operation.

In case of High RES scenario, generation pattern is the same as in Referent RES scenario, so the only difference in models is in installed capacities of additional RES.

8.2.4. HOPS models (HR)

In the year 2030, HOPS expects its transmission system to have 39 tie-lines at these voltage levels:

- 11 tie-lines of voltage level 400 kV
- 9 tie-lines of voltage level 220 kV
- 1 tie-line of voltage level 120 kV
- 18 tie-line of voltage level 110 kV

The elements used to model the power system of HR in 2030 are shown in *Table 112*.

Table 112: Number of elements in 2030 in the HR power system

815 BUSES	87 PLANTS	61 MACHINES	0 INDUCTION GENS	0 INDUCTION MOTORS
207 LOADS	229 FIXED SHUNTS	4 SWITCHED SHUNTS		
791 BRANCHES	405 TRANSFORMERS	0 DC LINES	0 FACTS DEVICES	0 GNE DEVICES

We show the expected installed generation capacities in the HR power system in 2030 in *Table 113*. This table shows the total maximum active power output; total rated apparent power; and the number of generation units. The data are given for each type of unit (fuel/technology type) and the last row shows the sum of all data in the corresponding column.

Table 113: Installed generation capacities in 2030 in the HR power system

Unit (fuel) type	Referent RES			High RES		
	Total P_{max} (MW)	Total S_n (MVA)	Number of units	Total P_{max} (MW)	Total S_n (MVA)	Number of units
Hard Coal old 2	110.00	156.00	1	110.00	156.00	1
Hard Coal new	210.00	247.00	1	210.00	247.00	1
CCGT NEW	648.00	700.60	7	648.00	700.60	7
Run-of-river (turbine)	413.60	454.00	17	413.60	454.00	17
Pump Storage Annual Reservoir (turbine)	1,777.50	1,911.80	24	1,777.50	1,911.80	24
Pump Storage / Daily reservoir (pump)	-730.00	910.00	4	-730.00	910.00	4
Pump Storage / Daily reservoir (turbine)	816.00	850.00	4	816.00	850.00	4
WIND ONSHORE	1,299.00	1,514.00	28	**1,496.00**	**1,716.00**	**32**
Solar (Photovoltaic)	605.80	669.03	13	**799.80**	**874.03**	**16**
Total	**5,149.90**	**7,412.43**	**99**	**5,540.90**	**7,819.43**	**106**

The right side of the table shows the data used for the High RES variant, and the differences compared to the Referent RES are shown in red. It can be seen that the variant with High RES includes four additional WPPs and three additional SPP.

We show the loading of branches in the HR transmission grid in *Figure 277*, for branches of voltage levels of 110 kV and above.

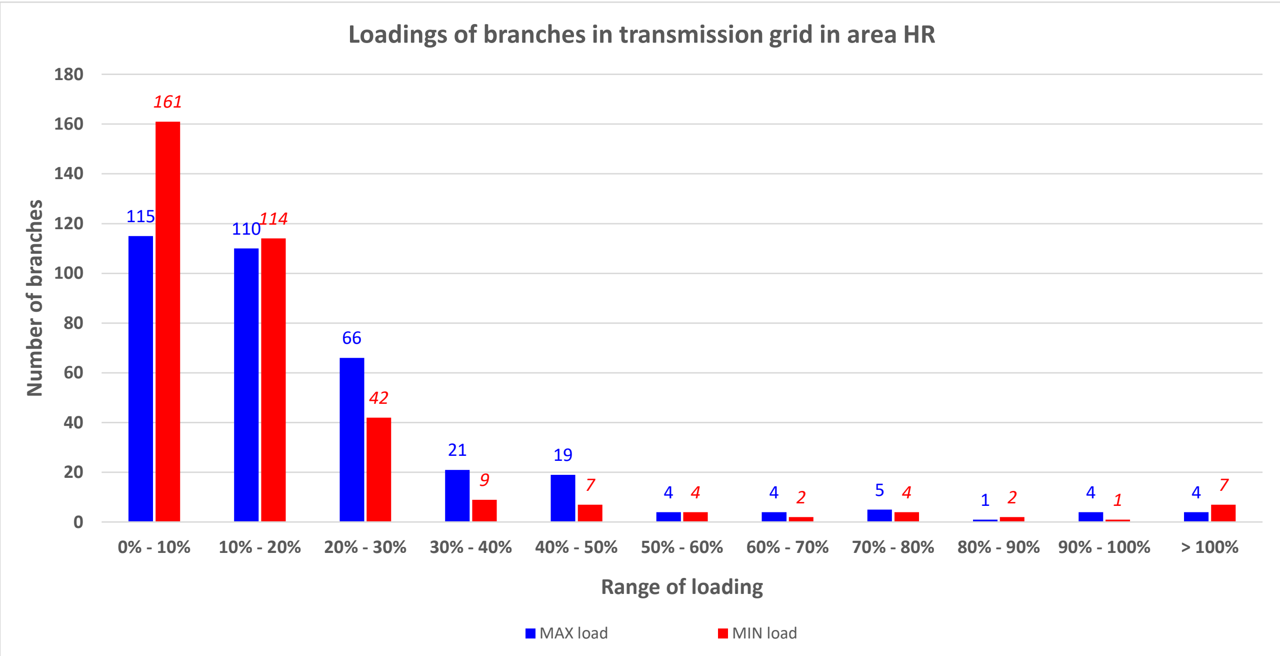


Figure 277: Histogram of branch loading in expected maximum and minimum regimes in 2030 in transmission grid of HR

From the figure, we see that there are overloaded branches in the HR transmission grid, and that most elements are loaded below 30%. During the maximum load regime, there are 8 branches loaded over 90%, and four have loadings over 100%.

During the minimum load regime, there are 8 branches loaded over 90%, and seven of them have a loadings over 100%.

Maximum load regime

We show the summary of area totals, as reported from PSS®E, for the maximum load 2030 regime in the Referent RES variant in *Table 114*. The first row represents data related to active power (in MW), while the second row shows data related to reactive power (in MVar).

Table 114: Area summary of HR power system in maximum load 2030 regime, variant Referent RES

X-- AREA --X	FROM GENE-RATION	AT AREA BUSES FROM IND GENERATN	AT AREA BUSES TO IND MOTORS	AT AREA BUSES 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
16	3162.1	0.0	0.0	2630.0	0.0	0.0	4.6	0.0	112.0	415.4	415.4	730.0
HR	-119.7	0.0	0.0	620.5	108.6	0.0	22.5	1564.4	846.7	-153.6	-153.6	

The total HR system load is 2.630 MW and 620,5 MVar, including auxiliary loads. The value of active power losses is around 116,6 MW, which is relatively around 4.43%, in comparison against total system active load. In this regime it is expected that HOPS exports around 730 MW to neighboring systems.

It should be noted that counting of total losses include all lines and transformers in this power system, including step up transformers and transformers to distribution network (if any).

We show the HR system summary per voltage level in *Table 115*. For each voltage level this table shows assigned total active and reactive power losses as well as part of this losses which resulted from line shunts (i.e. transformer magnetizing losses). Last column shows reactive power generated by line chargings.

Table 115: Summary per voltage levels in the HR power system for maximum load 2030, variant with Referent RES

VOLTAGE LEVEL	BRANCHES	X----- LOSSES -----X MW	MVAR	X-- LINE SHUNTS --X MW	MVAR	CHARGING MVAR
400.0	24	14.48	152.67	0.0	0.0	998.0
220.0	39	9.29	67.07	0.9	2.8	196.7
110.0	366	73.04	304.46	2.3	12.0	369.7
35.0	137	0.06	0.98	0.1	1.1	0.0
30.0	28	1.86	18.54	0.2	0.4	0.0
20.0	62	2.07	24.94	0.1	0.5	0.0
18.0	2	1.13	27.06	0.0	0.0	0.0
16.0	6	1.98	52.44	0.0	0.0	0.0
15.8	4	0.67	15.96	0.0	0.6	0.0
14.4	2	0.26	11.60	0.0	0.0	0.0
13.8	1	0.11	19.82	0.0	0.5	0.0
12.0	3	0.04	3.18	0.0	0.0	0.0
11.5	2	0.13	6.86	0.0	0.3	0.0
10.5	32	3.68	109.98	0.8	3.4	0.0
10.0	73	0.00	0.00	0.0	0.0	0.0
6.3	6	3.14	30.15	0.1	0.7	0.0
6.0	2	0.00	0.00	0.0	0.0	0.0
3.7	2	0.02	1.02	0.0	0.1	0.0
TOTAL	791	111.96	846.75	4.6	22.4	1564.4

From this table it can be seen that the most part of active power losses 65,2% is allocated in 110 kV, while losses in HV grid participate with 86,5% in total system losses.

We show the level of active power generation in the HR power system, in the maximum load regime for 2030, using Referent RES, *Table 116*. This table shows data per unit type (fuel/technology type) as well as the sum of all the data in corresponding columns, for operating units. It should be noted that this data shows output from generation units (values on transmission level must be decreased by auxiliary loads and losses in step up transformers).

The data include total active power generation and total maximum available active power, so we can estimate the active power reserve. In addition, we show total rated apparent power, so we can also estimate reactive power levels. Finally, each row shows the number of units in operation, and those that are overloaded.

Table 116: Active power generation in HR power system, maximum load regime, for 2030, Referent RES Case

Fuel type	Total P_{gen} (MW)	Total P_{max} (MW)	Total S_n (MVA)	Number of units
Hard Coal old 2	0.00	0.00	0.00	0
Hard Coal new	200.00	210.00	247.00	1
CCGT NEW	400.00	421.00	463.00	5
Run-of-river (turbine)	345.20	354.80	386.00	14
Pump Storage Annual Reservoir (turbine)	1,289.86	1,505.00	1,627.80	20
Pump Storage / Daily reservoir (pump)	0.00	0.00	0.00	0
Pump Storage / Daily reservoir (turbine)	388.00	408.00	425.00	2
WIND ONSHORE	539.00	731.00	826.10	19
Solar (Photovoltaic)	0.00	0.00	0.00	0
Total	**3,162.06**	**3,629.80**	**3,974.90**	**61**

This table shows that in the maximum load regime, there are 61 units in operation.

In case of High RES scenario, generation pattern is the same as in Referent RES scenario, so the only difference in models is in installed capacities of additional RES.

Minimum load regime

We show a summary of area totals, as reported from PSS®E, for the minimum load 2030 regime in the Referent RES case in *Table 117*. The first row represents data related to active power (in MW), while the second row shows data related to reactive power (in MVar).

Table 117: Area summary of HR power system in minimum load 2030 regime, variant Referent RES

```
                  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

   16           1209.8      0.0      0.0   1405.0      0.0      0.0      5.1       0.0     79.2    -279.6   -279.6    730.0
 HR             -145.2      0.0      0.0    331.4    119.0      0.0     24.6    1708.3    519.0     569.0    569.0
```

The total HR system load is 1.405 MW and 331,4 MVar, including auxiliary loads, so the total system active load is 53,4% of the maximum load. Value of active power losses is around 84,3 MW, which is around 6% of the total system active load. In this regime we would expect HOPS to export 730 MW to the neighboring systems.

It should be noted that counting of total losses include all lines and transformers in this power system, including step up transformers and transformers to distribution network (if any).

We show the HR system summary for each voltage level in *Table 118*, including the total active and reactive power losses, and the share of losses from line shunts (i.e., transformer magnetizing losses). The final column shows the reactive power generated by line chargings.

Table 118: Summary per voltage levels in the HR power system for minimum load 2030, variant with Referent RES

VOLTAGE LEVEL	BRANCHES	LOSSES MW	LOSSES MVAR	LINE SHUNTS MW	LINE SHUNTS MVAR	CHARGING MVAR
400.0	24	11.64	123.04	0.0	0.0	1082.1
220.0	39	4.90	41.22	1.0	3.0	215.8
110.0	366	59.04	242.19	2.5	13.0	410.4
35.0	137	0.00	0.05	0.1	1.3	0.0
30.0	28	0.02	1.93	0.2	0.5	0.0
20.0	62	0.00	0.00	0.1	0.5	0.0
18.0	2	0.00	0.00	0.0	0.0	0.0
16.0	6	1.75	46.21	0.0	0.0	0.0
15.8	4	0.00	0.00	0.0	0.6	0.0
14.4	2	0.26	11.57	0.0	0.0	0.0
13.8	1	0.00	0.00	0.0	0.6	0.0
12.0	3	0.00	0.00	0.0	0.0	0.0
11.5	2	0.00	0.00	0.0	0.4	0.0
10.5	32	1.48	48.71	0.9	3.8	0.0
10.0	73	0.00	0.00	0.0	0.0	0.0
6.3	6	0.10	3.11	0.2	0.8	0.0
6.0	2	0.00	0.00	0.0	0.0	0.0
3.7	2	0.02	0.98	0.0	0.1	0.0
TOTAL	791	79.23	519.00	5.1	24.6	1708.3

From this table it can be seen that the most part of active power losses 74,5% is allocated in 110 kV, while losses in HV grid participate with 95,4% in total system losses.

We show active power generation in the HR power system, in the minimum load regime for 2030, Referent RES case, in *Table 93*. This table shows the data per unit type (fuel/technology type) as well as the sum of all data in corresponding columns, for units in operation. This data shows the output from generation units (values on the transmission level must be decreased by auxiliary loads and losses in step-up transformers).

The data include total active power generation and total maximum available active power, so we can estimate active power reserve. In addition, we show the total rated apparent power, and can thus estimate reactive power possibilities. Finally, each row contains the number of units in operation.

Table 119: Active power generation in HR power system, minimum load regime, year 2030, Referent RES Case

Fuel type	Total P_{gen} (MW)	Total P_{max} (MW)	Total S_n (MVA)	Number of units
Hard Coal old 2	0.00	0.00	0.00	0
Hard Coal new	0.00	0.00	0.00	0
CCGT NEW	62.00	62.00	80.00	1
Run-of-river (turbine)	121.00	125.80	138.00	4
Pump Storage Annual Reservoir (turbine)	993.76	1,130.00	1,240.80	16
Pump Storage / Daily reservoir (pump)	0.00	0.00	0.00	0
Pump Storage / Daily reservoir (turbine)	0.00	0.00	0.00	0
WIND ONSHORE	33.00	42.00	44.20	1
Solar (Photovoltaic)	0.00	0.00	0.00	0
Total	**1,209.76**	**1,359.80**	**1,503.00**	**22**

We see that in the minimum load regime, there are 22 units in operation.

In case of High RES scenario, generation pattern is the same as in Referent RES scenario, so the only difference in models is in installed capacities of additional RES.

8.2.5. IPTO models (GR)

In the year 2030, IPTO expects its transmission system to have 8 tie-lines at these voltage levels:

- 6 tie-lines of voltage level 400 kV
- 1 HVDC interconnection of 400kV voltage level
- 1 tie-line of voltage level 150 kV

The elements used to model the power system of GR in 2030 are shown in *Table 120*.

Table 120: Number of elements in models of GR in 2030

```
 2000 BUSES        419 PLANTS        401 MACHINES       0 INDUCTION GENS       0 INDUCTION MOTORS
  445 LOADS         42 FIXED SHUNTS  127 SWITCHED SHUNTS
 2375 BRANCHES     784 TRANSFORMERS    2 DC LINES       1 FACTS DEVICES        0 GNE DEVICES
```

We show the expected installed generation capacities in the GR power system in 2030 in *Table 121*. This table shows the total maximum active power output; total rated apparent power; and the number of generation units. The data are given for each type of unit (fuel/technology type) and the last row shows the sum of all data in the corresponding column.

Table 121: Installed generation capacities in 2030 in the GR power system

Unit (fuel) type	Referent RES			High RES		
	Total P_{max} (MW)	Total S_n (MVA)	Number of units	Total P_{max} (MW)	Total S_n (MVA)	Number of units
CCGT OLD 2	1,026.50	1,357.97	7	1,026.50	1,357.97	7
CCGT NEW	6,303.93	7,915.35	18	6,303.93	7,915.35	18
OCGT OLD	147.76	189.50	3	147.76	189.50	3
OCGT NEW	450.00	570.00	3	450.00	570.00	3
LIGHT OIL	323.39	499.74	8	323.39	499.74	8
Heavy oil old 2	98.00	128.36	2	98.00	128.36	2
Run-of-river (turbine)	419.27	289.87	31	419.27	289.87	31
Pump Storage Annual Reservoir (pump)	-710.00	782.00	6	-710.00	782.00	6
Pump Storage Annual Reservoir (turbine)	3,406.70	3,810.90	45	3,406.70	3,810.90	45
Pump Storage / Daily reservoir (pump)	-735.00	771.00	6	-735.00	771.00	6
Pump Storage / Daily reservoir (turbine)	699.00	771.00	6	699.00	771.00	6
WIND ONSHORE	6,683.30	7,325.59	155	**8,618.30**	**9,460.92**	**157**
Wind Offshore	316.70	348.83	5	**181.70**	**197.50**	**3**
Solar (Photovoltaic)	7,721.03	8,581.38	159	**9,621.03**	**10,689.84**	**159**
Solar (Thermal)	255.51	315.30	11	255.51	315.30	11
Others renewable	154.46	176.49	23	154.46	176.49	23
Others non-renewable	295.54	338.13	22	295.54	338.13	22
Total	**26,856.09**	**34,171.41**	**510**	**30,556.09**	**38,263.87**	**510**

The right side of the table shows the data used for the High RES variant, and the differences compared to the Referent RES are shown in red. It can be seen that the variant with High RES does not include additional WPPs or SPPs, only additional installed capacity.

We show the loading of branches in the GR transmission grid in *Figure 278*, for branches of voltage levels of 110 kV and above.

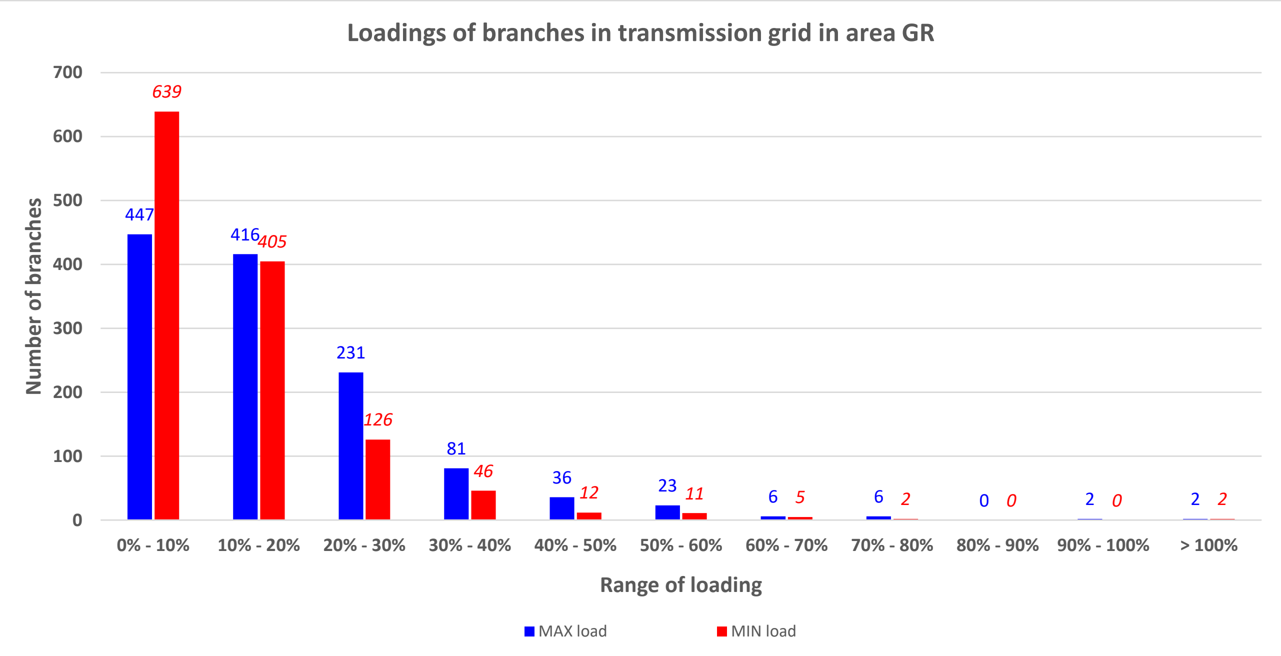


Figure 278: Histogram of branch loading in expected maximum and minimum regimes in 2030 in transmission grid of GR

From the figure, we see that there are overloaded branches in the GR transmission grid, and that most elements are loaded below 30%. During the maximum load regime, there are 4 branches loaded over 90%, and two of them are overloaded.

During the minimum load regime, almost all the elements have loadings below 60%. There are two branches with loading of 70% – 80% and two branches with loading over 100%.

Maximum load regime

We show the summary of area totals, as reported from PSS®E, for the maximum load 2030 regime in the Referent RES variant in *Table 122*. The first row represents data related to active power (in MW), while the second row shows data related to reactive power (in MVar).

Table 122: Area summary of GR power system in maximum load 2030 regime, variant Referent RES

X-- AREA --X	FROM GENE-RATION	AT AREA BUSES: FROM IND GENERATN	AT AREA BUSES: TO IND MOTORS	AT AREA BUSES: 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
30	9159.8	0.0	0.0	8374.0	0.0	0.0	0.0	0.0	185.2	600.6	600.6	601.0
GR	574.0	0.0	0.0	4124.6	1812.6	0.0	22.5	7651.1	2017.1	248.3	248.3	

The total GR system load is 8.374 MW and 4.124,6 MVar, including auxiliary loads. The value of active power losses is around 185,2 MW, which is around 2,21%, in comparison against total system active load. In this regime it is expected that IPTO exports around 601 MW to neighboring systems.

It should be noted that counting of total losses include all lines and transformers in this power system, including step up transformers and transformers to distribution network (if any).

We show the GR system summary per voltage level in *Table 123*. For each voltage level this table shows assigned total active and reactive power losses as well as part of this losses which resulted from line shunts (i.e. transformer magnetizing losses). Last column shows reactive power generated by line chargings.

Table 123: Summary per voltage levels in the GR power system for maximum load 2030, variant with Referent RES

VOLTAGE		X----- LOSSES	-----X	X-- LINE SHUNTS	--X	CHARGING
LEVEL	BRANCHES	MW	MVAR	MW	MVAR	MVAR
DC	2	13.70	-73.49			
400.0	117	32.99	326.20	0.0	0.0	3892.8
150.0	1209	99.72	833.60	0.0	12.7	3476.8
66.0	5	0.00	0.00	0.0	0.7	1.2
33.0	5	0.01	0.09	0.0	0.0	2.5
30.0	7	0.01	0.12	0.0	0.0	3.6
21.0	4	2.30	313.99	0.0	0.0	0.0
20.0	602	3.97	60.64	0.0	2.1	273.9
19.0	2	3.26	105.31	0.0	0.2	0.0
18.0	1	1.02	29.48	0.0	0.1	0.0
17.0	3	3.43	98.23	0.0	0.5	0.0
16.0	1	0.47	13.58	0.0	0.1	0.0
15.8	40	21.13	219.36	0.0	2.7	0.0
15.8	3	2.03	20.30	0.0	0.0	0.0
15.0	35	1.04	41.62	0.0	1.0	0.2
13.8	2	0.00	0.00	0.0	0.1	0.0
11.5	4	0.00	0.00	0.0	0.1	0.0
11.0	4	0.00	0.00	0.0	0.3	0.0
6.3	1	0.08	2.28	0.0	0.0	0.0
1.0	20	0.01	0.08	0.0	0.0	0.0
0.8	4	0.00	0.11	0.0	0.0	0.0
0.8	31	0.01	0.60	0.0	0.0	0.0
0.7	57	0.00	0.14	0.0	0.0	0.0
0.7	15	0.00	0.03	0.0	0.0	0.0
0.4	203	0.04	24.86	0.0	0.0	0.0
TOTAL	2377	185.24	2017.12	0.0	20.6	7651.1

From this table it can be seen that the most part of active power losses 53,8% is allocated in 110 kV, while losses in HV grid participate with 79% in total system losses.

We show the level of active power generation in the GR power system, in the maximum load regime for 2030, using Referent RES, *Table 124*. This table shows data per unit type (fuel/technology type) as well as the sum of all the data in corresponding columns, for operating units. It should be noted that this data shows output from generation units (values on transmission level must be decreased by auxiliary loads and losses in step up transformers).

The data include total active power generation and total maximum available active power, so we can estimate the active power reserve. In addition, we show total rated apparent power, so we can also estimate reactive power levels. Finally, each row shows the number of units in operation, and those that are overloaded.

Table 124: Active power generation in GR power system, maximum load regime, for 2030, Referent RES Case

Fuel type	Total P_{gen} (MW)	Total P_{max} (MW)	Total S_n (MVA)	Number of units
CCGT OLD 2	462.24	476.30	606.00	3
CCGT NEW	5,331.50	5,449.04	6,814.97	16
OCGT OLD	0.00	0.00	0.00	0
OCGT NEW	0.00	0.00	0.00	0
LIGHT OIL	0.00	0.00	0.00	0
Heavy oil old 2	0.00	0.00	0.00	0
Run-of-river (turbine)	137.00	291.26	155.01	8
Pump Storage Annual Reservoir (pump)	0.00	0.00	0.00	0
Pump Storage Annual Reservoir (turbine)	997.00	1,830.88	2,036.00	25
Pump Storage / Daily reservoir (pump)	0.00	0.00	0.00	0
Pump Storage / Daily reservoir (turbine)	600.00	699.00	771.00	6
WIND ONSHORE	291.85	6,683.30	7,325.59	155
Wind Offshore	15.15	316.70	348.83	5
Solar (Photovoltaic)	1,090.11	7,721.03	8,581.38	159
Solar (Thermal)	0.00	0.00	0.00	0
Others renewable	79.03	89.15	101.25	11
Others non-renewable	155.97	175.92	201.57	13
Total	**9,159.85**	**23,732.58**	**26,941.60**	**401**

This table shows that in the maximum load regime, there are 401 units in operation.

In the case of the High RES scenario, a different generation pattern is defined. Generation per fuel type is shown in *Table 125*. From the table it can be seen that the differences are significant, in comparison to the Referent RES scenario.

Table 125: Active power generation in GR power system, maximum load regime, for 2030, High RES Case

Fuel type	Total P_{gen} (MW)	Total P_{max} (MW)	Total S_n (MVA)	Number of units
CCGT OLD 2	462.24	476.30	606.00	3
CCGT NEW	4,957.33	5,071.38	6,346.97	15
OCGT OLD	0.00	0.00	0.00	0
OCGT NEW	0.00	0.00	0.00	0
LIGHT OIL	0.00	0.00	0.00	0
Heavy oil old 2	0.00	0.00	0.00	0
Run-of-river (turbine)	137.00	291.26	155.01	8
Pump Storage Annual Reservoir (pump)	0.00	0.00	0.00	0
Pump Storage Annual Reservoir (turbine)	1,024.66	1,830.88	2,036.00	25
Pump Storage / Daily reservoir (pump)	0.00	0.00	0.00	0
Pump Storage / Daily reservoir (turbine)	600.00	699.00	771.00	6
WIND ONSHORE	377.48	8,618.30	9,460.92	157
Wind Offshore	7.96	181.70	197.50	3
Solar (Photovoltaic)	1,369.42	9,621.03	10,689.84	159
Solar (Thermal)	0.00	0.00	0.00	0
Others renewable	79.03	89.15	101.25	11
Others non-renewable	155.97	175.92	201.57	13
Total	**9,171.09**	**27,054.92**	**30,566.06**	**400**

As result of this different generation pattern, total values related to this area are not changed. Summary of area totals, as report from PSS®E, in shown in *Table 126*.

Table 126: Area summary of GR power system in maximum load 2030 regime, variant Referent 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
30	9171.1	0.0	0.0	8374.0	0.0	0.0	0.0	0.0	196.5	600.6	600.6	601.0
GR	428.7	0.0	0.0	4124.5	1794.6	0.0	22.4	7676.8	1917.3	246.7	246.7	

Due to different generation pattern the value of active power losses is changed, 196,5 MW compared to the 185,2 MW in referent RES scenario.

Minimum load regime

We show a summary of area totals, as reported from PSS®E, for the minimum load 2030 regime in the Referent RES case in *Table 127*. The first row represents data related to active power (in MW), while the second row shows data related to reactive power (in MVar).

Table 127: Area summary of GR power system in minimum load 2030 regime, variant Referent 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
30	5505.3	0.0	0.0	5168.7	0.0	0.0	0.0	0.0	101.5	235.1	235.1	235.0
GR	-1354.4	0.0	0.0	2653.7	2097.5	0.0	21.9	7995.6	1915.7	-47.7	-47.7	

The total GR system load is 5.168.7 MW and 2.653,7 MVar, including auxiliary loads, so the total system active load is 61,7% of the maximum load. Value of active power losses is around 101,5 MW, which is around 1,96% of the total system active load. In this regime we would expect IPTO to exports 235 MW to the neighboring systems.

It should be noted that counting of total losses include all lines and transformers in this power system, including step up transformers and transformers to distribution network (if any).

We show the GR system summary for each voltage level in *Table 128*, including the total active and reactive power losses, and the share of losses from line shunts (i.e., transformer magnetizing losses). The final column shows the reactive power generated by line chargings.

Table 128: Summary per voltage levels in the GR power system for minimum load 2030, variant with Referent RES

VOLTAGE		X----- LOSSES -----X		X-- LINE SHUNTS --X		CHARGING
LEVEL	BRANCHES	MW	MVAR	MW	MVAR	MVAR
DC	2	8.02	613.70			
400.0	115	19.53	191.01	0.0	0.0	3948.0
150.0	1207	55.25	476.81	0.0	13.3	3749.0
66.0	5	0.00	0.00	0.0	0.7	1.4
33.0	5	0.12	0.84	0.0	0.0	2.6
30.0	7	0.15	1.23	0.0	0.0	3.9
21.0	3	0.16	253.03	0.0	0.0	0.0
20.0	602	7.90	64.92	0.0	2.2	290.5
17.0	3	3.35	95.92	0.0	0.5	0.0
15.8	32	5.24	149.96	0.0	1.7	0.0
15.8	2	1.03	10.31	0.0	0.0	0.0
15.0	35	0.32	18.52	0.0	1.0	0.2
13.8	2	0.00	0.00	0.0	0.1	0.0
11.5	4	0.00	0.00	0.0	0.1	0.0
11.0	4	0.00	0.00	0.0	0.3	0.0
6.3	1	0.19	5.46	0.0	0.0	0.0
1.0	20	0.07	0.97	0.0	0.0	0.0
0.8	4	0.00	1.28	0.0	0.0	0.0
0.8	31	0.12	7.44	0.0	0.0	0.0
0.7	57	0.04	3.55	0.0	0.0	0.0
0.7	15	0.00	0.82	0.0	0.0	0.0
0.4	62	0.01	19.93	0.0	0.0	0.0
TOTAL	2218	101.51	1915.70	0.0	19.9	7995.6

From this table it can be seen that the most part of active power losses 54,4% is allocated in 110 kV, while losses in HV grid participate with 81,6% in total system losses.

We show active power generation in the GR power system, in the minimum load regime for 2030, Referent RES case, in *Table 129*. This table shows the data per unit type (fuel/technology type) as well as the sum of all data in corresponding columns, for units in operation. This data shows the output from generation units (values on the transmission level must be decreased by auxiliary loads and losses in step-up transformers).

The data include total active power generation and total maximum available active power, so we can estimate active power reserve. In addition, we show the total rated apparent power, and can thus estimate reactive power possibilities. Finally, each row contains the number of units in operation.

Table 129: Active power generation in GR power system, minimum load regime, year 2030, Referent RES Case

Fuel type	Total P_{gen} (MW)	Total P_{max} (MW)	Total S_n (MVA)	Number of units
CCGT OLD 2	0.00	0.00	0.00	0
CCGT NEW	3,055.24	3,410.74	4,318.53	9
OCGT OLD	0.00	0.00	0.00	0
OCGT NEW	0.00	0.00	0.00	0
LIGHT OIL	0.00	0.00	0.00	0
Heavy oil old 2	0.00	0.00	0.00	0
Run-of-river (turbine)	137.00	291.26	155.01	8
Pump Storage Annual Reservoir (pump)	-100.00	-113.80	125.00	1
Pump Storage Annual Reservoir (turbine)	1,202.59	1,612.50	1,778.00	23
Pump Storage / Daily reservoir (pump)	-200.00	-245.00	257.00	2
Pump Storage / Daily reservoir (turbine)	0.00	0.00	0.00	0
WIND ONSHORE	1,143.40	6,808.78	7,459.69	155
Wind Offshore	32.11	191.22	214.73	5
Solar (Photovoltaic)	0.00	0.00	0.00	0
Solar (Thermal)	0.00	0.00	0.00	0
Others renewable	79.03	89.15	101.25	11
Others non-renewable	155.97	175.92	201.57	13
Total	**5,505.34**	**12,220.77**	**14,610.78**	**227**

We see that in the minimum load regime, there are 227 units in operation.

In the case of the High RES scenario, a different generation pattern is defined. Generation per fuel type is shown in *Table 130*. From the table it can be seen that differences are significant, in comparison to the Referent RES scenario.

Table 130: Active power generation in GR power system, minimum load regime, year 2030, High RES Case

Fuel type	Total P_{gen} (MW)	Total P_{max} (MW)	Total S_n (MVA)	Number of units
CCGT OLD 2	0.00	0.00	0.00	0
CCGT NEW	3,055.24	3,410.74	4,318.53	9
OCGT OLD	0.00	0.00	0.00	0
OCGT NEW	0.00	0.00	0.00	0
LIGHT OIL	0.00	0.00	0.00	0
Heavy oil old 2	0.00	0.00	0.00	0
Run-of-river (turbine)	137.00	291.26	155.01	8
Pump Storage Annual Reservoir (pump)	-100.00	-113.80	125.00	1
Pump Storage Annual Reservoir (turbine)	1,202.33	1,612.50	1,778.00	23
Pump Storage / Daily reservoir (pump)	-200.00	-245.00	257.00	2
Pump Storage / Daily reservoir (turbine)	0.00	0.00	0.00	0
WIND ONSHORE	1,447.27	8,618.30	9,460.92	157
Wind Offshore	30.51	181.70	197.50	3
Solar (Photovoltaic)	0.00	0.00	0.00	0
Solar (Thermal)	0.00	0.00	0.00	0
Others renewable	79.03	89.15	101.25	11
Others non-renewable	155.97	175.92	201.57	13
Total	**5,807.35**	**14,020.77**	**16,594.78**	**227**

As result of this different generation pattern, total values related to this area are changed. Summary of area totals, as report from PSS®E, in shown in *Table 131*.

Table 131: Area summary of GR power system in minimum load 2030 regime, variant Referent RES

```
                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

    30         5807.4      0.0       0.0   5168.7      0.0      0.0      0.0      0.0    103.2     535.4    535.4    535
  GR          -1066.6      0.0       0.0   2652.9   2052.0      0.0     21.5   7885.0   1904.2     187.7    187.7
```

Due to different generation pattern the value of active power losses is changed, 196,5 MW compared to the 185,2 MW in referent RES scenario. In this regime IPTO exports 535 MW to the neighboring systems, compared to the 235 MW in the referent RES scenario.

8.2.6. KOSTT models (XK)

In the year 2030, KOSTT expects its transmission system to have 6 tie-lines at these voltage levels:

- 4 tie-lines of voltage level 400 kV
- 2 tie-lines of voltage level 220 kV

The elements used to model the power system of XK in 2030 are shown in *Table 132*.

Table 132: Number of elements in models of XK in 2030

```
 171 BUSES          19 PLANTS            16 MACHINES        0 INDUCTION GENS        0 INDUCTION MOTORS
  83 LOADS           0 FIXED SHUNTS       0 SWITCHED SHUNTS
 210 BRANCHES      117 TRANSFORMERS       0 DC LINES          0 FACTS DEVICES          0 GNE DEVICES
```

We show the expected installed generation capacities in the XK power system in 2030 in *Table 133*. This table shows the total maximum active power output; total rated apparent power; and the number of generation units. The data are given for each type of unit (fuel/technology type) and the last row shows the sum of all data in the corresponding column.

Table 133: Installed generation capacities in 2030 in the XK power system

Unit (fuel) type	Referent RES			High RES		
	Total P_{max} (MW)	Total S_n (MVA)	Number of units	Total P_{max} (MW)	Total S_n (MVA)	Number of units
Lignite old 2	678.00	798.00	2	678.00	798.00	2
LIGNITE NEW	500.00	587.77	1	500.00	587.80	1
Run-of-river (turbine)	70.00	77.90	3	70.00	77.90	3
Pump Storage & Storage / Weekly reservoir (pum	-250.00	400.00	4	-250.00	400.00	4
Pump Storage & Storage / Weekly reservoir (turbi	250.00	294.00	4	250.00	294.00	4
WIND ONSHORE	335.60	393.20	6	**484.00**	**537.80**	6
Solar (Photovoltaic)	180.20	181.37	3	**204.20**	**221.06**	3
Total	**1,763.80**	**2,732.24**	**23**	**1,936.20**	**2,916.56**	**23**

The right side of the table shows the data used for the High RES variant, and the differences compared to the Referent RES are shown in red. It can be seen that the variant with High RES does not include additional WPPs or SPPs, only additional installed capacity.

We show the loading of branches in the XK transmission grid in *Figure 279*, for branches of voltage levels of 110 kV and above.

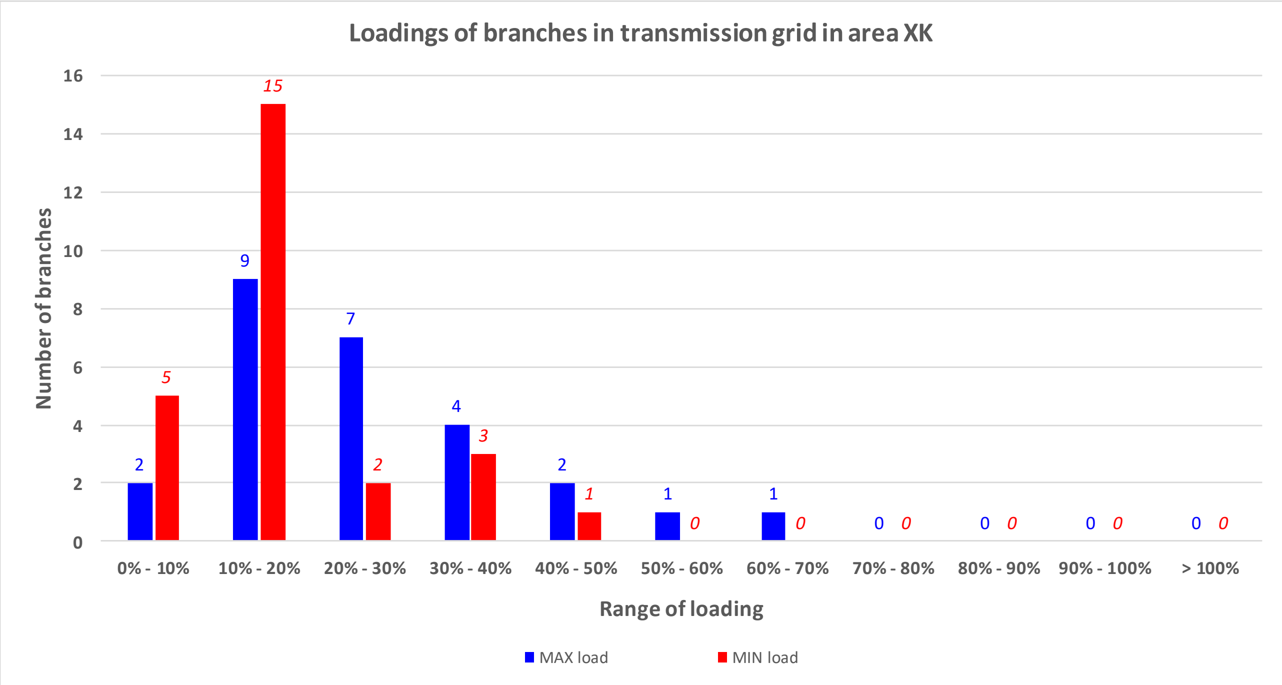


Figure 279: Histogram of branch loading in expected maximum and minimum regimes in 2030 in transmission grid of XK

From the figure, we see that there are no overloaded branches in the XK transmission grid, and that most elements are loaded below 40%. During the maximum load regime, there are 2 branches loaded over 50%, and one have loading of 60% – 70%.

During the minimum load regime, almost all the elements have loadings below 40%. There is only one branch with loading of 40% – 50%.

Maximum load regime

We show the summary of area totals, as reported from PSS®E, for the maximum load 2030 regime in the Referent RES variant in *Table 134*. The first row represents data related to active power (in MW), while the second row shows data related to reactive power (in MVar).

Table 134: Area summary of XK power system in maximum load 2030 regime, variant Referent 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
47	1479.2	0.0	0.0	1440.0	0.0	0.0	4.9	0.0	33.7	0.5	0.5	1.0
XK	257.2	0.0	0.0	476.9	0.0	0.0	14.7	234.5	429.8	-429.6	-429.6	

The total XK system load is 1.440 MW and 476,9 MVar, including auxiliary loads. The value of active power losses is around 38,6 MW, which is relatively around 2,68%, in comparison against total system active load. In this regime it is expected that KOSTT has zero exchange with neighboring systems.

It should be noted that counting of total losses include all lines and transformers in this power system, including step up transformers and transformers to distribution network (if any).

We show the XK system summary per voltage level in *Table 135*. For each voltage level this table shows assigned total active and reactive power losses as well as part of this losses which resulted from line shunts (i.e. transformer magnetizing losses). Last column shows reactive power generated by line chargings.

Table 135: Summary per voltage levels in the XK power system for maximum load 2030, variant with Referent RES

VOLTAGE LEVEL	BRANCHES	LOSSES MW	LOSSES MVAR	LINE SHUNTS MW	LINE SHUNTS MVAR	CHARGING MVAR
400.0	7	3.49	40.68	0.0	0.0	153.5
220.0	26	9.42	89.38	0.8	2.1	52.4
110.0	109	16.41	148.79	1.8	2.5	28.6
35.0	28	1.39	35.78	0.5	1.6	0.0
24.0	3	1.52	77.74	1.1	6.9	0.0
10.0	33	1.43	36.05	0.7	1.1	0.0
6.3	4	0.07	1.41	0.1	0.5	0.0
TOTAL	210	33.73	429.83	4.9	14.7	234.5

From this table it can be seen that most of the active power losses, 48,7%, are allocated in the 110 kV system, while losses in the HV grid participate with 86,9% in total system losses.

We show the level of active power generation in the XK power system, in the maximum load regime for 2030, using Referent RES, in *Table 136*. This table shows data per unit type (fuel/technology type) as well as the sum of all the data in corresponding columns, for operating units. It should be noted that this data shows output from generation units (values on transmission level must be decreased by auxiliary loads and losses in step up transformers).

The data include total active power generation and total maximum available active power, so we can estimate the active power reserve. In addition, we show total rated apparent power, so we can also estimate reactive power levels. Finally, each row shows the number of units in operation, and those that are overloaded.

Table 136: Active power generation in XK power system, maximum load regime, for 2030, Referent RES Case

Fuel type	Total P_{gen} (MW)	Total P_{max} (MW)	Total S_n (MVA)	Number of units
Lignite old 2	552.18	678.00	798.00	2
LIGNITE NEW	445.00	500.00	587.77	1
Run-of-river (turbine)	42.00	70.00	77.90	3
Pump Storage & Storage / Weekly reservoir (pum	0.00	0.00	0.00	0
Pump Storage & Storage / Weekly reservoir (turbi	200.00	250.00	294.00	4
WIND ONSHORE	240.00	335.60	393.20	6
Solar (Photovoltaic)	0.00	0.00	0.00	0
Total	**1,479.18**	**1,833.60**	**2,150.87**	**16**

This table shows that in the maximum load regime, there are 16 units in operation.

In case of High RES scenario, slightly different generation pattern is defined. Generation per fuel type is shown in *Table 137*. From the table it can be seen that differences are not so significant, in comparison against Referent RES scenario, so there should not be significant influence to total values related to this area.

Table 137: Active power generation in XK power system, maximum load regime, for 2030, High RES Case

Fuel type	Total P_{gen} (MW)	Total P_{max} (MW)	Total S_n (MVA)	Number of units
Lignite old 2	568.22	678.00	798.00	2
LIGNITE NEW	445.00	500.00	587.80	1
Run-of-river (turbine)	18.00	52.50	58.40	2
Pump Storage & Storage / Weekly reservoir (pum	0.00	0.00	0.00	0
Pump Storage & Storage / Weekly reservoir (turbi	170.00	250.00	294.00	4
WIND ONSHORE	279.00	484.00	537.80	6
Solar (Photovoltaic)	0.00	0.00	0.00	0
Total	**1,480.22**	**1,964.50**	**2,276.00**	**15**

Minimum load regime

We show a summary of area totals, as reported from PSS®E, for the minimum load 2030 regime in the Referent RES case in Table 138. The first row represents data related to active power (in MW), while the second row shows data related to reactive power (in MVar).

Table 138: Area summary of XK power system in minimum load 2030 regime, variant Referent RES

```
                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

   47           738.9       0.0      0.0     700.0       0.0       0.0      5.8       0.0      13.0        20.0      20.0      20.0
 XK            -290.8       0.0      0.0     233.6       0.0       0.0     17.2     271.4     165.2      -435.4    -435.4
```

The total XK system load is 700 MW and 233,6 MVar, including auxiliary loads, including auxiliary loads, so the total system active load is 48,6% of the maximum load. Value of active power losses is around 18,8 MW, which is around 2,68% of the total system active load. In this regime we would expect KOSTT to export 20 MW to the neighboring systems.

It should be noted that counting of total losses include all lines and transformers in this power system, including step up transformers and transformers to distribution network (if any).

We show the XK system summary for each voltage level in Table 139, including the total active and reactive power losses, and the share of losses from line shunts (i.e., transformer magnetizing losses). The final column shows the reactive power generated by line chargings.

Table 139: Summary per voltage levels in the XK power system for minimum load 2030, variant with Referent RES

```
VOLTAGE        X----- LOSSES -----X    X-- LINE SHUNTS --X    CHARGING
LEVEL BRANCHES       MW        MVAR         MW        MVAR        MVAR
400.0       7      2.18       25.30        0.0         0.0       173.7
220.0      26      4.61       32.61        0.9         2.5        62.5
110.0     109      4.61       39.11        2.2         3.0        35.2
 35.0      28      0.62       16.96        0.6         1.9         0.0
 24.0       3      0.73       45.69        1.2         7.8         0.0
 10.0      33      0.21        5.37        0.9         1.4         0.0
  6.3       4      0.01        0.14        0.1         0.6         0.0
TOTAL     210     12.97      165.17        5.8        17.2       271.4
```

From this table it can be seen that the most part of active power losses 35,5% is allocated in 110 kV, while losses in HV grid participate with 87,9% in total system losses.

We show active power generation in the XK power system, in the minimum load regime for 2030, Referent RES case, in Table 140. This table shows the data per unit type (fuel/technology type) as well as the sum of all data in corresponding columns, for units in operation. This data shows the output from generation units (values on the transmission level must be decreased by auxiliary loads and losses in step-up transformers).

The data include total active power generation and total maximum available active power, so we can estimate active power reserve. In addition, we show the total rated apparent power, and can thus estimate reactive power possibilities. Finally, each row contains the number of units in operation.

Table 140: Active power generation in XK power system, minimum load regime, year 2030, Referent RES Case

Fuel type	Total P_{gen} (MW)	Total P_{max} (MW)	Total S_n (MVA)	Number of units
Lignite old 2	63.88	339.00	399.00	1
LIGNITE NEW	445.00	500.00	587.77	1
Run-of-river (turbine)	0.00	0.00	0.00	0
Pump Storage & Storage / Weekly reservoir (pum	0.00	0.00	0.00	0
Pump Storage & Storage / Weekly reservoir (turbi	20.00	62.50	73.50	1
WIND ONSHORE	210.00	335.60	393.20	6
Solar (Photovoltaic)	0.00	0.00	0.00	0
Total	**738.88**	**1,237.10**	**1,453.47**	**9**

We see that in the minimum load regime, there are 9 units in operation.

In case of High RES scenario, slightly different generation pattern is defined. Generation per fuel type is shown in Table 141. From the table it can be seen that differences are not so significant, in comparison against Referent RES scenario, so there should not be significant influence to total values related to this area.

Table 141: Active power generation in XK power system, minimum load regime, year 2030, High RES Case

Fuel type	Total P_{gen} (MW)	Total P_{max} (MW)	Total S_n (MVA)	Number of units
Lignite old 2	93.80	339.00	399.00	1
LIGNITE NEW	445.00	500.00	587.80	1
Run-of-river (turbine)	0.00	0.00	0.00	0
Pump Storage & Storage / Weekly reservoir (pum	0.00	0.00	0.00	0
Pump Storage & Storage / Weekly reservoir (turbi	0.00	0.00	0.00	0
WIND ONSHORE	240.00	484.00	537.80	6
Solar (Photovoltaic)	0.00	0.00	0.00	0
Total	**778.80**	**1,323.00**	**1,524.60**	**8**

8.2.7. CGES models (ME)

In the year 2030, CGES expects its transmission system to have 13 tie-lines at these voltage levels:

- 5 tie-lines of voltage level 400 kV
- 4 tie-lines of voltage level 220 kV
- 4 tie-line of voltage level 110 kV

The elements used to model the power system of ME in 2030 are shown in *Table 142*.

Table 142: Number of elements in models of ME in 2030

```
  240 BUSES          27 PLANTS           27 MACHINES        0 INDUCTION GENS       0 INDUCTION MOTORS
   81 LOADS           0 FIXED SHUNTS      0 SWITCHED SHUNTS
  209 BRANCHES      102 TRANSFORMERS      0 DC LINES        0 FACTS DEVICES        0 GNE DEVICES
```

We show the expected installed generation capacities in the ME power system in 2030 in *Table 143*. This table shows the total maximum active power output; total rated apparent power; and the number of generation units. The data are given for each type of unit (fuel/technology type) and the last row shows the sum of all data in the corresponding column.

Table 143: Installed generation capacities in 2030 in the ME power system

Unit (fuel) type	Referent RES			High RES		
	Total P_{max} (MW)	Total S_n (MVA)	Number of units	Total P_{max} (MW)	Total S_n (MVA)	Number of units
Lignite new	250.00	270.00	1	250.00	270.00	1
Run-of-river (turbine)	238.40	264.00	8	238.40	264.00	8
Pump Storage & Storage / Weekly reservoir (turbine)	875.50	941.00	14	875.50	941.00	14
WIND ONSHORE	240.00	252.65	4	**368.00**	**387.11**	**6**
Solar (Photovoltaic)	300.00	318.00	6	300.00	318.00	6
Total	**1,903.90**	**2,045.65**	**33**	**2,031.90**	**2,180.11**	**35**

The right side of the table shows the data used for the High RES variant, and the differences compared to the Referent RES are shown in red. It can be seen that the variant with High RES includes two additional WPPs.

We show the loading of branches in the ME transmission grid in *Figure 280*, for branches of voltage levels of 110 kV and above.

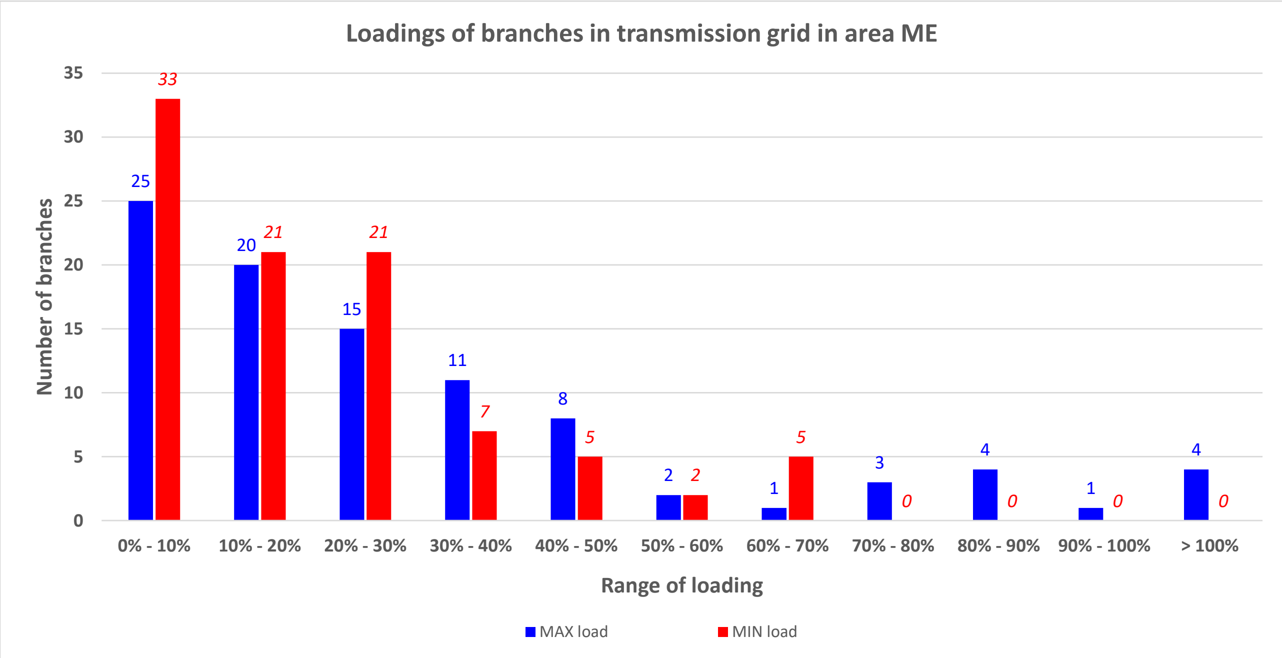


Figure 280: Histogram of branch loading in expected maximum and minimum regimes in 2030 in transmission grid of ME

From the figure, we see that there are overloaded branches in ME transmission grid, and that most elements are loaded below 50%. During the maximum load regime, there are 9 branches loaded over 80%, and four of them are overloaded.

During the minimum load regime, almost all the elements have loadings below 50%. There are two branches with loadings of 50% – 60% and five branches with loadings of 60% – 70%.

Maximum load regime

We show the summary of area totals, as reported from PSS®E, for the maximum load 2030 regime in the Referent RES variant in *Table 144*. The first row represents data related to active power (in MW), while the second row shows data related to reactive power (in MVar).

Table 144: Area summary of ME power system in maximum load 2030 regime, variant Referent RES

X-- AREA --X	FROM GENE- RATION	AT AREA BUSES FROM IND GENERATN	AT AREA BUSES TO IND MOTORS	AT AREA BUSES 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
38	1477.5	0.0	0.0	838.0	0.0	0.0	4.3	0.0	68.2	567.0	567.0	567.0
ME	447.9	0.0	0.0	285.6	0.0	0.0	29.3	429.0	659.5	-97.5	-97.5	

The total ME system load is 838 MW and 285,6 MVar, including auxiliary loads. The value of active power losses is around 72.5 MW, which is relatively around 8,6%, in comparison against total system active load. In this regime it is expected that CGES exports around 567 MW to neighboring systems.

It should be noted that counting of total losses include all lines and transformers in this power system, including step up transformers and transformers to distribution network (if any).

We show the ME system summary per voltage level in *Table 145*. For each voltage level this table shows assigned total active and reactive power losses as well as part of this losses which resulted from line shunts (i.e. transformer magnetizing losses). Last column shows reactive power generated by line chargings.

Table 145: Summary per voltage levels in the ME power system for maximum load 2030, variant with Referent RES

```
 VOLTAGE       X----- LOSSES -----X    X-- LINE SHUNTS --X   CHARGING
LEVEL BRANCHES       MW         MVAR         MW        MVAR        MVAR
400.0      11      20.00      232.12        0.0         0.0       286.0
220.0      11      16.06      119.87        0.3         3.3        51.1
110.0      99      25.59       90.23        1.0        10.6        91.9
 35.0      48       1.40       52.24        1.2         5.8         0.0
 30.0       1       0.13        4.02        0.0         0.1         0.0
 15.8       4       1.67       70.82        0.5         3.7         0.0
 13.8       2       0.37       11.54        0.2         0.3         0.0
 10.5      14       1.94       44.00        0.6         2.7         0.0
 10.0      16       0.41       10.85        0.4         1.8         0.0
  6.3       3       0.66       23.82        0.1         0.8         0.0
TOTAL     209      68.23      659.52        4.2        29.2       429.0
```

From this table it can be seen that the most part of active power losses 37,5% is allocated in 110 kV, while losses in HV grid participate with 90,4% in total system losses.

We show the level of active power generation in the ME power system, in the maximum load regime for 2030, using Referent RES, in *Table 146*. This table shows data per unit type (fuel/technology type) as well as the sum of all the data in corresponding columns, for operating units. It should be noted that this data shows output from generation units (values on transmission level must be decreased by auxiliary loads and losses in step up transformers).

The data include total active power generation and total maximum available active power, so we can estimate the active power reserve. In addition, we show total rated apparent power, so we can also estimate reactive power levels. Finally, each row shows the number of units in operation, and those that are overloaded.

Table 146: Active power generation in ME power system, maximum load regime, for 2030, Referent RES Case

Fuel type	Total P_{gen} (MW)	Total P_{max} (MW)	Total S_n (MVA)	Number of units
Lignite new	250.00	250.00	270.00	1
Run-of-river (turbine)	202.00	238.40	264.00	8
Pump Storage & Storage / Weekly reservoir (turbi	815.54	875.50	941.00	14
WIND ONSHORE	210.00	240.00	252.65	4
Solar (Photovoltaic)	0.00	0.00	0.00	0
Total	**1,477.54**	**1,603.90**	**1,727.65**	**27**

This table shows that in the maximum load regime, there are 27 units in operation.

In case of High RES scenario, generation pattern is the same as in Referent RES scenario, so the only difference in models is in installed capacities of additional RES.

Minimum load regime

We show a summary of area totals, as reported from PSS®E, for the minimum load 2030 regime in the Referent RES case in *Table 147*. The first row represents data related to active power (in MW), while the second row shows data related to reactive power (in MVar).

Table 147: Area summary of ME power system in minimum load 2030 regime, variant Referent RES

X-- AREA --X	FROM GENE-RATION	AT AREA BUSES FROM IND GENERATN	AT AREA BUSES TO IND MOTORS	AT AREA BUSES 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
38	701.5	0.0	0.0	410.0	0.0	0.0	4.3	0.0	26.2	261.0	261.0	261.0
ME	0.9	0.0	0.0	138.6	0.0	0.0	28.5	466.8	261.1	39.5	39.5	

The total ME system load is 410 MW and 138,6 MVar, including auxiliary loads, so the total system active load is 48,9% of the maximum load. Value of active power losses is around 30,5 MW, which is around 7,43% of the total system active load. In this regime we would expect CGES to export 261 MW to the neighboring systems.

It should be noted that counting of total losses include all lines and transformers in this power system, including step up transformers and transformers to distribution network (if any).

We show the ME system summary for each voltage level in Table 148, including the total active and reactive power losses, and the share of losses from line shunts (i.e., transformer magnetizing losses). The final column shows the reactive power generated by line chargings.

Table 148: Summary per voltage levels in the ME power system for minimum load 2030, variant with Referent RES

VOLTAGE LEVEL	BRANCHES	LOSSES MW	LOSSES MVAR	LINE SHUNTS MW	LINE SHUNTS MVAR	CHARGING MVAR
400.0	11	10.93	126.91	0.0	0.0	310.7
220.0	11	3.24	23.04	0.3	3.6	55.0
110.0	99	9.57	36.21	1.1	11.5	101.1
35.0	47	0.28	16.35	1.4	6.4	0.0
30.0	1	0.02	0.56	0.0	0.2	0.0
15.8	2	0.38	14.52	0.2	1.5	0.0
13.8	2	0.10	3.10	0.2	0.3	0.0
10.5	11	1.38	30.34	0.5	2.3	0.0
10.0	16	0.10	2.43	0.4	2.0	0.0
6.3	2	0.21	7.69	0.1	0.6	0.0
TOTAL	202	26.22	261.15	4.2	28.5	466.8

From this table it can be seen that the most part of active power losses 36,5% is allocated in 110 kV, while losses in HV grid participate with 90,5% in total system losses.

We show active power generation in the ME power system, in the minimum load regime for 2030, Referent RES case, in Table 149. This table shows the data per unit type (fuel/technology type) as well as the sum of all data in corresponding columns, for units in operation. This data shows the output from generation units (values on the transmission level must be decreased by auxiliary loads and losses in step-up transformers).

The data include total active power generation and total maximum available active power, so we can estimate active power reserve. In addition, we show the total rated apparent power, and can thus estimate reactive power possibilities. Finally, each row contains the number of units in operation.

Table 149: Active power generation in ME power system, minimum load regime, year 2030, Referent RES Case

Fuel type	Total P_{gen} (MW)	Total P_{max} (MW)	Total S_n (MVA)	Number of units
Lignite new	0.00	0.00	0.00	0
Run-of-river (turbine)	122.00	156.20	173.00	6
Pump Storage & Storage / Weekly reservoir (turbi	476.91	573.50	617.00	9
WIND ONSHORE	102.57	168.00	176.85	3
Solar (Photovoltaic)	0.00	0.00	0.00	0
Total	**701.48**	**897.70**	**966.85**	**18**

We see that in the minimum load regime, there are 18 units in operation.

In case of High RES scenario, generation pattern is the same as in Referent RES scenario, so the only difference in models is in installed capacities of additional RES.

8.2.8. MEPSO models (MK)

In the year 2030, MEPSO expects its transmission system to have 8 tie-lines at these voltage levels:

- 6 tie-lines of voltage level 400 kV
- 2 tie-line of voltage level 110 kV

The elements used to model the power system of MK in 2030 are shown in *Table 150*.

Table 150: Number of elements in 2030 in the MK power system

```
 375 BUSES          68 PLANTS          24 MACHINES        0 INDUCTION GENS        0 INDUCTION MOTORS
  85 LOADS           0 FIXED SHUNTS     4 SWITCHED SHUNTS
 420 BRANCHES      230 TRANSFORMERS     0 DC LINES        0 FACTS DEVICES         0 GNE DEVICES
```

We show the expected installed generation capacities in the MK power system in 2030 in *Table 151*. This table shows the total maximum active power output; total rated apparent power; and the number of generation units. The data are given for each type of unit (fuel/technology type) and the last row shows the sum of all data in the corresponding column.

Table 151: Installed generation capacities in 2030 in the MK power system

Unit (fuel) type	Referent RES			High RES		
	Total P_{max} (MW)	Total S_n (MVA)	Number of units	Total P_{max} (MW)	Total S_n (MVA)	Number of units
Lignite old 1	466.00	551.40	2	466.00	551.40	2
Conventional gas old 1	60.00	77.50	3	60.00	77.50	3
CCGT OLD 1	257.00	311.70	2	257.00	311.70	2
Run-of-river (turbine)	214.50	146.00	6	214.50	146.00	6
Pump Storage Annual Reservoir (turbine)	650.00	1,068.10	20	650.00	1,068.10	20
Pump Storage / Daily reservoir (turbine)	37.00	41.00	2	37.00	41.00	2
WIND ONSHORE	306.00	398.05	8	**366.00**	**451.60**	**9**
Solar (Photovoltaic)	403.00	2,900.00	29	**550.01**	**3,200.00**	**32**
Others renewable	27.00	100.00	1	27.00	100.00	1
Total	**2,420.50**	**5,593.75**	**73**	**2,627.51**	**5,947.30**	**77**

The right side of the table shows the data used for the High RES variant, and the differences compared to the Referent RES are shown in red. It can be seen that the variant with High RES includes one additional WPPs and three additional SPP.

We show the loading of branches in the MK transmission grid in *Figure 281*, for branches of voltage levels of 110 kV and above.

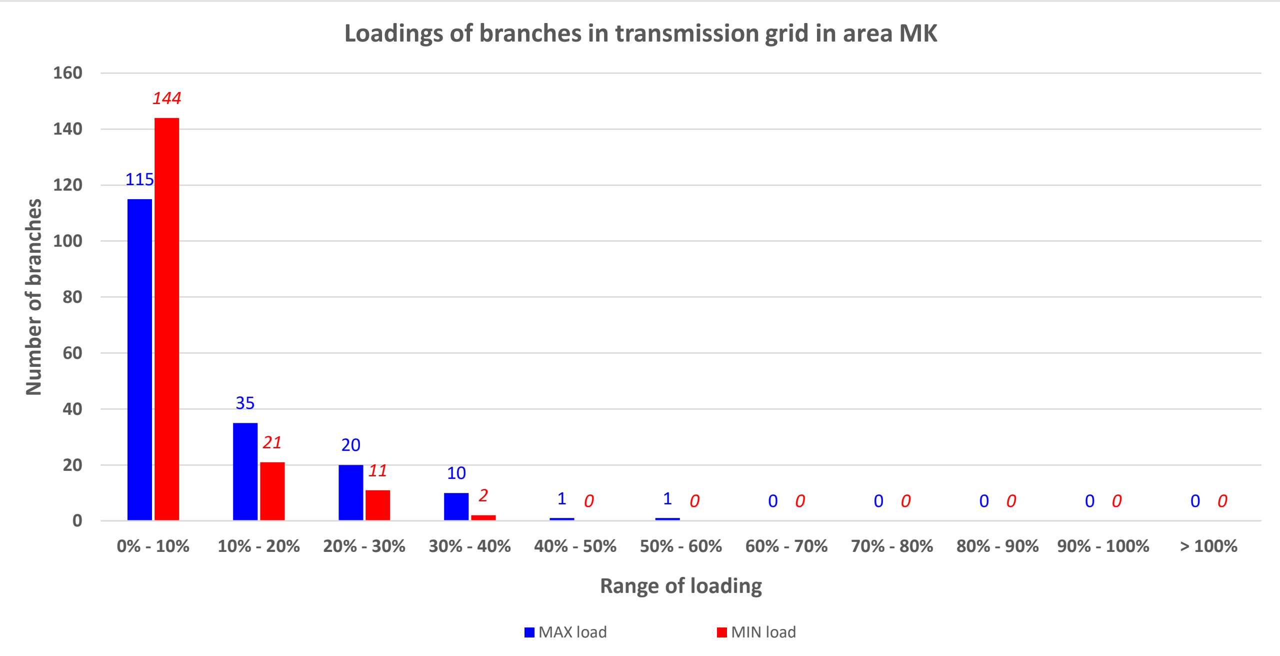


Figure 281: Histogram of branch loading in expected maximum and minimum regimes in 2030 in transmission grid of MK

From the figure, we see that there are no overloaded branches in the MK transmission grid, and that most elements are loaded below 10%. During the maximum load regime, there are 2 branches loaded over 40%, and one have loading of 50% – 60%.

During the minimum load regime, almost all the elements have loadings below 30%. There are just two branches with loadings of 30% – 40%.

Maximum load regime

We show the summary of area totals, as reported from PSS®E, for the maximum load 2030 regime in the Referent RES variant in *Table 152*. The first row represents data related to active power (in MW), while the second row shows data related to reactive power (in MVar).

Table 152: Area summary of MK power system in maximum load 2030 regime, variant Referent 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	TO TIES + LOADS	DESIRED NET INT
37	720.3	0.0	0.0	1393.0	0.0	0.0	2.0	0.0	12.3	-687.0	-687.0	-687.0
MK	279.4	0.0	0.0	488.8	0.0	0.0	8.3	485.5	148.8	119.0	119.0	

The total MK system load is 1.393 MW and 488,8 MVar, including auxiliary loads. The value of active power losses is around 14,3 MW, which is relatively around 1,02%, in comparison against total system active load. In this regime it is expected that MEPSO imports around 687 MW from neighboring systems.

It should be noted that counting of total losses include all lines and transformers in this power system, including step up transformers and transformers to distribution network (if any).

We show the MK system summary per voltage level in *Table 153*. For each voltage level this table shows assigned total active and reactive power losses as well as part of this losses which resulted from line shunts (i.e. transformer magnetizing losses). Last column shows reactive power generated by line chargings.

Table 153: Summary per voltage levels in the MK power system for maximum load 2030, variant with Referent RES

VOLTAGE LEVEL	BRANCHES	X----- LOSSES -----X MW	MVAR	X-- LINE SHUNTS --X MW	MVAR	CHARGING MVAR
400.0	13	1.62	17.48	0.0	0.0	369.3
110.0	184	8.83	74.72	0.0	0.0	116.1
35.0	60	0.29	1.76	1.0	3.4	0.1
21.0	37	0.00	0.00	0.0	0.0	0.0
20.0	32	0.04	0.28	0.4	1.3	0.0
15.8	2	0.66	30.18	0.0	0.0	0.0
15.0	1	0.00	0.00	0.0	0.0	0.0
13.8	2	0.00	4.21	0.0	0.0	0.0
12.0	4	0.30	5.76	0.0	0.0	0.0
10.5	18	0.51	14.12	0.0	0.0	0.0
10.0	47	0.02	0.26	0.6	2.4	0.0
6.3	20	0.00	0.00	0.0	0.0	0.0
TOTAL	420	12.28	148.77	2.0	7.1	485.5

From this table it can be seen that the most part of active power losses 71,9% is allocated in 110 kV, while losses in HV grid participate with 85,1% in total system losses.

We show the level of active power generation in the MK power system, in the maximum load regime for 2030, using Referent RES, *Table 154*. This table shows data per unit type (fuel/technology type) as well as the sum of all the data in corresponding columns, for operating units. It should be noted that this data shows output from generation units (values on transmission level must be decreased by auxiliary loads and losses in step up transformers).

The data include total active power generation and total maximum available active power, so we can estimate the active power reserve. In addition, we show total rated apparent power, so we can also estimate reactive power levels. Finally, each row shows the number of units in operation, and those that are overloaded.

Table 154: Active power generation in MK power system, maximum load regime, for 2030, Referent RES Case

Fuel type	Total P_{gen} (MW)	Total P_{max} (MW)	Total S_n (MVA)	Number of units
Lignite old 1	365.27	466.00	551.40	2
Conventional gas old 1	0.00	0.00	0.00	0
CCGT OLD 1	0.00	0.00	0.00	0
Run-of-river (turbine)	22.49	41.50	46.00	5
Pump Storage Annual Reservoir (turbine)	297.32	460.50	716.50	14
Pump Storage / Daily reservoir (turbine)	19.23	37.00	41.00	2
WIND ONSHORE	0.00	0.00	0.00	0
Solar (Photovoltaic)	0.00	0.00	0.00	0
Others renewable	16.00	27.00	100.00	1
Total	**720.31**	**1,032.00**	**1,454.90**	**24**

This table shows that in the maximum load regime, there are 24 units in operation.

In case of High RES scenario, generation pattern is the same as in Referent RES scenario, so the only difference in models is in installed capacities of additional RES.

Minimum load regime

We show a summary of area totals, as reported from PSS®E, for the minimum load 2030 regime in the Referent RES case in *Table 155*. The first row represents data related to active power (in MW), while the second row shows data related to reactive power (in MVar).

Table 155: Area summary of MK power system in minimum load 2030 regime, variant Referent 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	TO TIES + LOADS	DESIRED NET INT
37	580.4	0.0	0.0	632.3	0.0	0.0	2.2	0.0	5.9	-60.0	-60.0	-60.0
MK	136.8	0.0	0.0	242.1	0.0	0.0	9.0	510.7	76.5	320.0	320.0	

The total MK system load is 632,3 MW and 242,1 MVar, including auxiliary loads, so the total system active load is 45,4% of the maximum load. Value of active power losses is around 8,1 MW, which is around 1,28% of the total system active load. In this regime we would expect MEPSO to import 60 MW from the neighboring systems.

It should be noted that counting of total losses include all lines and transformers in this power system, including step up transformers and transformers to distribution network (if any).

We show the MK system summary for each voltage level in *Table 156*, including the total active and reactive power losses, and the share of losses from line shunts (i.e., transformer magnetizing losses). The final column shows the reactive power generated by line chargings.

Table 156: Summary per voltage levels in the MK power system for minimum load 2030, variant with Referent RES

```
  VOLTAGE          X----- LOSSES -----X    X-- LINE SHUNTS --X    CHARGING
LEVEL  BRANCHES        MW         MVAR         MW         MVAR       MVAR
400.0      13        1.24        13.38        0.0         0.0       384.7
110.0     184        3.82        21.86        0.0         0.0       125.9
 35.0      60        0.00         0.00        1.0         3.6         0.1
 21.0      37        0.00         0.00        0.0         0.0         0.0
 20.0      32        0.04         0.29        0.4         1.4         0.0
 15.8       2        0.56        25.54        0.0         0.0         0.0
 15.0       1        0.11        13.38        0.0         0.0         0.0
 13.8       2        0.00         0.00        0.0         0.0         0.0
 12.0       4        0.11         1.73        0.0         0.0         0.0
 10.5      18        0.00         0.00        0.0         0.0         0.0
 10.0      47        0.03         0.28        0.7         2.6         0.0
  6.3      20        0.00         0.00        0.0         0.0         0.0
TOTAL     420        5.91        76.47        2.1         7.6       510.7
```

From this table it can be seen that the most part of active power losses 64,6% is allocated in 110 kV, while losses in HV grid participate with 85,6% in total system losses.

We show active power generation in the MK power system, in the minimum load regime for 2030, Referent RES case, in *Table 157*. This table shows the data per unit type (fuel/technology type) as well as the sum of all data in corresponding columns, for units in operation. This data shows the output from generation units (values on the transmission level must be decreased by auxiliary loads and losses in step-up transformers).

The data include total active power generation and total maximum available active power, so we can estimate active power reserve. In addition, we show the total rated apparent power, and can thus estimate reactive power possibilities. Finally, each row contains the number of units in operation.

Table 157: Active power generation in MK power system, minimum load regime, year 2030, Referent RES Case

Fuel type	Total P_{gen} (MW)	Total P_{max} (MW)	Total S_n (MVA)	Number of units
Lignite old 1	364.43	466.00	551.40	2
Conventional gas old 1	0.00	0.00	0.00	0
CCGT OLD 1	160.00	206.00	225.00	1
Run-of-river (turbine)	0.00	0.00	0.00	0
Pump Storage Annual Reservoir (turbine)	40.00	86.00	92.00	2
Pump Storage / Daily reservoir (turbine)	0.00	0.00	0.00	0
WIND ONSHORE	0.00	0.00	0.00	0
Solar (Photovoltaic)	0.00	0.00	0.00	0
Others renewable	16.00	27.00	100.00	1
Total	**580.43**	**785.00**	**968.40**	**6**

We see that in the minimum load regime, there are 6 units in operation.

In the High RES scenario, the generation pattern is the same as in the Referent RES scenario, so the only difference in the models is in the installed capacities of additional RES.

8.2.9. Transelectrica models (RO)

In the year 2030, Transelectrica expects its transmission system to have 14 tie-lines at 400kV voltage levels.

The elements used to model the power system of RO in 2030 are shown in Table 158.

Table 158: Number of elements in 2030 in the RO power system

```
 1289 BUSES        362 PLANTS           286 MACHINES       0 INDUCTION GENS       0 INDUCTION MOTORS
  734 LOADS          0 FIXED SHUNTS      12 SWITCHED SHUNTS
 1706 BRANCHES     446 TRANSFORMERS       0 DC LINES         0 FACTS DEVICES        0 GNE DEVICES
```

We show the expected installed generation capacities in the RO power system in 2030 in

Table 159. This table shows the total maximum active power output; total rated apparent power; and the number of generation units. The data are given for each type of unit (fuel/technology type) and the last row shows the sum of all data in the corresponding column.

Table 159: Installed generation capacities in 2030 in the RO power system

Unit (fuel) type	Referent RES			High RES		
	Total P_{max} (MW)	Total S_n (MVA)	Number of units	Total P_{max} (MW)	Total S_n (MVA)	Number of units
Nuclear	2,126.00	2,400.00	3	2,126.00	2,400.00	3
Lignite old 1	3,790.00	4,539.00	17	3,790.00	4,539.00	17
Hard Coal old 1	505.00	573.50	4	505.00	573.50	4
Conventional gas old 1	1,199.43	1,505.03	37	1,199.43	1,505.03	37
CCGT old 1	100.00	150.00	2	100.00	150.00	2
CCGT new	1,774.25	2,102.57	15	1,774.25	2,102.57	15
OCGT new	138.44	124.67	4	138.44	124.67	4
Run-of-river (turbine)	2,928.69	3,054.20	61	2,928.69	3,054.20	61
Pump Storage Annual Reservoir (turbine)	193.00	205.96	3	193.00	205.96	3
Pump Storage & Storage / Weekly reservoir (turbine)	2,728.24	2,912.67	60	2,728.24	2,912.67	60
Swell RoR and Daily Storage (turbine)	186.22	187.22	4	186.22	187.22	4
Wind Onshore	4,200.04	4,421.10	81	**5,099.91**	**5,368.32**	**82**
Solar (Photovoltaic)	1,999.80	2,221.96	78	**3,698.76**	**4,109.74**	**86**
Others renewable	274.05	303.04	28	500.07	555.63	28
Total	**22,143.16**	**24,700.92**	**397**	**24,968.01**	**27,788.51**	**406**

The right side of the table shows the data used for the High RES variant, and the differences compared to the Referent RES are shown in red. It can be seen that the variant with High RES includes one additional WPP and eight additional SPPs.

We show the loading of branches in the RO transmission grid in Figure 282, for branches of voltage levels of 110 kV and above.

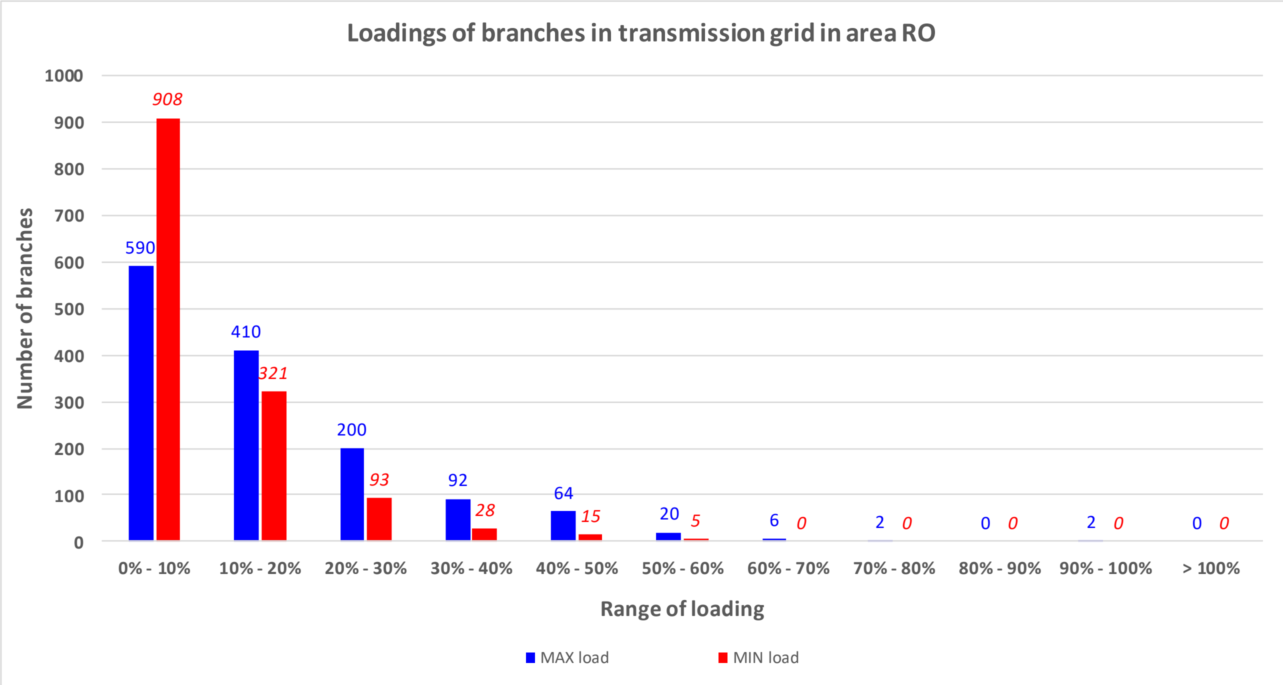


Figure 282: Histogram of branch loading in expected maximum and minimum regimes in 2030 in transmission grid of RO

From the figure, we see that there are not overloaded branches in the RO transmission grid, and that most elements are loaded below 20%. During the maximum load regime, there are 4 branches loaded over 70%, and two have loadings of 90% – 100%.

During the minimum load regime, almost all the elements have loadings below 60%. There are just five branches with loadings of 50% – 60%.

Maximum load regime

We show the summary of area totals, as reported from PSS®E, for the maximum load 2030 regime in the Referent RES variant in Table 160. The first row represents data related to active power (in MW), while the second row shows data related to reactive power (in MVar).

Table 160: Area summary of RO power system in maximum load 2030 regime, variant Referent RES

	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
44	11126.3	0.0	0.0	10253.8	0.0	0.0	96.0	0.0	226.3	550.1	550.1	550.0
RO	420.3	0.0	0.0	2219.5	1386.5	0.0	274.5	5554.0	2653.1	-559.4	-559.4	

The total RO system load is 10.253,8 MW and 2.219,5 MVar, including auxiliary loads. The value of active power losses is around 322,3 MW, which is relatively around 3,14%, in comparison against total system active load. In this regime it is expected that Transelectrica exports 550 MW to the neighboring systems.

It should be noted that counting of total losses include all lines and transformers in this power system, including step up transformers and transformers to distribution network (if any).

We show the RO system summary per voltage level in Table 161. For each voltage level this table shows assigned total active and reactive power losses as well as part of this losses which resulted from line shunts (i.e. transformer magnetizing losses). Last column shows reactive power generated by line chargings.

Table 161: Summary per voltage levels in the RO power system for maximum load 2030, variant with Referent RES

VOLTAGE LEVEL	BRANCHES	LOSSES MW	LOSSES MVAR	LINE SHUNTS MW	LINE SHUNTS MVAR	CHARGING MVAR
400.0	104	57.89	715.28	54.9	32.0	3736.3
220.0	88	42.98	263.18	11.2	0.1	631.4
110.0	1205	98.64	702.08	12.9	122.1	1186.3
33.0	15	0.56	13.70	0.5	2.9	0.0
30.0	16	0.34	14.17	0.6	2.8	0.0
24.0	9	5.04	260.29	2.4	16.5	0.0
20.0	13	0.25	8.01	0.4	1.7	0.0
18.0	1	0.25	9.00	0.2	0.9	0.0
17.0	2	0.87	62.23	0.3	2.9	0.0
15.8	18	4.44	195.19	1.9	14.5	0.0
15.0	1	0.28	12.08	0.1	0.0	0.0
10.5	119	9.02	259.90	6.0	55.8	0.0
6.3	72	3.97	117.05	1.9	17.8	0.0
1.0	3	0.32	4.58	0.2	0.3	0.0
0.7	34	1.43	15.74	2.2	3.9	0.0
0.4	6	0.07	0.63	0.4	0.4	0.0
TOTAL	1706	226.33	2653.14	96.0	274.5	5554.0

From this table it can be seen that the most part of active power losses 43,6% is allocated in 110 kV, while losses in HV grid participate with 88,2% in total system losses.

We show the level of active power generation in the RO power system, in the maximum load regime for 2030, using Referent RES, **Table 162**. This table shows data per unit type (fuel/technology type) as well as the sum of all the data in corresponding columns, for operating units. It should be noted that this data shows output from generation units (values on transmission level must be decreased by auxiliary loads and losses in step up transformers).

The data include total active power generation and total maximum available active power, so we can estimate the active power reserve. In addition, we show total rated apparent power, so we can also estimate reactive power levels. Finally, each row shows the number of units in operation, and those that are overloaded.

Table 162: Active power generation in RO power system, maximum load regime, for 2030, Referent RES Case

Fuel type	Total P_{gen} (MW)	Total P_{max} (MW)	Total S_n (MVA)	Number of units
Nuclear	1,416.00	1,416.00	1,600.00	2
Lignite old 1	1,424.04	2,000.00	2,427.50	10
Hard Coal old 1	395.47	505.00	573.50	4
Conventional gas old 1	416.17	582.48	691.18	29
CCGT old 1	83.69	100.00	150.00	2
CCGT new	1,589.08	1,760.00	2,087.90	14
OCGT new	65.68	127.00	113.06	3
Run-of-river (turbine)	2,338.94	2,796.93	2,921.92	52
Pump Storage Annual Reservoir (turbine)	134.13	193.00	205.96	3
Pump Storage & Storage / Weekly reservoir (turbine)	1,698.94	2,310.11	2,461.61	57
Swell RoR and Daily Storage (turbine)	148.67	186.22	187.22	4
Wind Onshore	1,197.90	3,994.04	4,204.25	78
Solar (Photovoltaic)	0.00	0.00	0.00	0
Others renewable	217.60	274.05	303.04	28
Total	**11,126.31**	**16,244.83**	**17,927.14**	**286**

This table shows that in the maximum load regime, there are 286 units in operation.

In case of High RES scenario, different generation pattern is defined. Generation per fuel type is shown in *Table 163*. From the table it can be seen that differences are significant, in comparison against Referent RES scenario.

Table 163: Active power generation in RO power system, maximum load regime, for 2030, High RES Case

Fuel type	Total P_{gen} (MW)	Total P_{max} (MW)	Total S_n (MVA)	Number of units
Nuclear	2,126.00	2,126.00	2,400.00	3
Lignite old 1	808.20	1,010.00	1,263.50	7
Hard Coal old 1	263.23	355.00	397.00	3
Conventional gas old 1	413.07	599.43	710.02	30
CCGT old 1	83.69	100.00	150.00	2
CCGT new	1,399.96	1,760.00	2,087.90	14
OCGT new	65.68	127.00	113.06	3
Run-of-river (turbine)	2,394.61	2,836.51	2,961.61	52
Pump Storage Annual Reservoir (turbine)	134.13	193.00	205.96	3
Pump Storage & Storage / Weekly reservoir (turbine)	1,753.29	2,307.90	2,462.79	57
Swell RoR and Daily Storage (turbine)	148.67	186.22	187.22	4
Wind Onshore	1,499.94	5,099.91	5,368.32	82
Solar (Photovoltaic)	0.00	0.00	0.00	0
Others renewable	217.60	274.05	303.04	28
Total	**11,308.07**	**16,975.02**	**18,610.42**	**288**

As result of this different generation pattern, total values related to this area are changed. Summary of area totals, as report from PSS®E, in shown in *Table 164*.

Table 164: Area summary of RO power system in maximum load 2030 regime, variant Referent RES

X-- AREA --X	FROM GENERATION	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
44	11307.5	0.0	0.0	10229.8	0.0	0.0	97.5	0.0	230.1	750.1	750.1	750.0
RO	434.4	0.0	0.0	2205.2	1400.6	0.0	281.3	5631.6	2746.4	-567.5	-567.5	

Due to different generation pattern the value of active power losses is changed, 327,6 MW compared to the 322,3 MW in the referent RES scenario. In this regime Transelectrica exports 750 MW to the neighboring systems, compared to the 550 MW in the referent RES scenario.

Minimum load regime

We show a summary of area totals, as reported from PSS®E, for the minimum load 2030 regime in the Referent RES case in Table 165. The first row represents data related to active power (in MW), while the second row shows data related to reactive power (in MVar).

Table 165: Area summary of RO power system in minimum load 2030 regime, variant Referent RES

X-- AREA --X	FROM GENERATION	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
44	5709.1	0.0	0.0	5163.5	0.0	0.0	87.6	0.0	108.4	349.7	349.7	350.0
RO	-550.5	0.0	0.0	1665.2	2100.3	0.0	205.1	5590.9	1394.4	-324.3	-324.3	

The total RO system load is 5.163,5 MW and 1.665,2 MVar, including auxiliary loads, so the total system active load is 50,36% of the maximum load. Value of active power losses is around 196 MW, which is around 3.79%of the total system active load. In this regime we would expect Transelectrica to export around 350 MW to the neighboring systems.

It should be noted that counting of total losses include all lines and transformers in this power system, including step up transformers and transformers to distribution network (if any).

We show the RO system summary for each voltage level in Table 166, including the total active and reactive power losses, and the share of losses from line shunts (i.e., transformer magnetizing losses). The final column shows the reactive power generated by line chargings.

Table 166: Summary per voltage levels in the RO power system for minimum load 2030, variant with Referent RES

VOLTAGE		X----- LOSSES -----X		X-- LINE SHUNTS --X		CHARGING
LEVEL	BRANCHES	MW	MVAR	MW	MVAR	MVAR
400.0	102	54.06	608.97	55.6	30.6	3787.4
220.0	83	18.32	106.93	10.5	0.1	583.7
110.0	1197	24.52	202.32	12.3	116.3	1219.8
33.0	11	0.37	9.58	0.5	2.6	0.0
30.0	10	0.45	15.31	0.4	2.2	0.0
24.0	8	4.28	221.22	2.1	14.6	0.0
20.0	5	0.08	2.84	0.2	0.7	0.0
17.0	2	0.48	34.55	0.3	2.8	0.0
15.8	9	1.97	92.88	1.2	9.8	0.0
15.0	1	0.34	14.76	0.1	0.0	0.0
10.5	36	1.61	46.42	1.9	15.7	0.0
6.3	23	0.89	26.98	0.7	6.3	0.0
1.0	2	0.18	2.60	0.1	0.1	0.0
0.7	22	0.67	7.66	1.6	2.8	0.0
0.4	5	0.13	1.39	0.4	0.4	0.0
TOTAL	1516	108.35	1394.42	87.6	205.1	5590.9

From this table it can be seen that the most part of active power losses 22,6% is allocated in 110 kV, while losses in HV grid participate with 89,4% in total system losses.

We show active power generation in the RO power system, in the minimum load regime for 2030, Referent RES case, in **Table 167**. This table shows the data per unit type (fuel/technology type) as well as the sum of all data in corresponding columns, for units in operation. This data shows the output from generation units (values on the transmission level must be decreased by auxiliary loads and losses in step-up transformers).

The data include total active power generation and total maximum available active power, so we can estimate active power reserve. In addition, we show the total rated apparent power, and can thus estimate reactive power possibilities. Finally, each row contains the number of units in operation.

Table 167: Active power generation in RO power system, minimum load regime, year 2030, Referent RES Case

Fuel type	Total P_{gen} (MW)	Total P_{max} (MW)	Total S_n (MVA)	Number of units
Nuclear	1,380.00	1,416.00	1,600.00	2
Lignite old 1	988.23	1,520.00	1,814.50	6
Hard Coal old 1	171.84	235.00	247.00	1
Conventional gas old 1	72.45	172.36	189.55	8
CCGT old 1	54.16	100.00	150.00	2
CCGT new	835.96	1,130.00	1,363.00	6
OCGT new	25.59	83.00	91.77	2
Run-of-river (turbine)	1,098.31	2,294.74	2,419.01	45
Pump Storage Annual Reservoir (turbine)	45.00	101.50	114.32	2
Pump Storage & Storage / Weekly reservoir (turbine)	130.00	191.07	204.06	4
Swell RoR and Daily Storage (turbine)	0.00	0.00	0.00	0
Wind Onshore	800.80	2,860.59	3,011.14	43
Solar (Photovoltaic)	0.00	0.00	0.00	0
Others renewable	106.80	158.01	175.38	17
Total	**5,709.14**	**10,262.27**	**11,379.73**	**138**

We see that in the minimum load regime, there are 138 units in operation.

In case of High RES scenario, different generation pattern is defined. Generation per fuel type is shown in *Table 168*. From the table it can be seen that differences are significant, in comparison against Referent RES scenario.

Table 168: Active power generation in RO power system, minimum load regime, year 2030, High RES Case

Fuel type	Total P_{gen} (MW)	Total P_{max} (MW)	Total S_n (MVA)	Number of units
Nuclear	2,090.00	2,126.00	2,400.00	3
Lignite old 1	911.42	1,190.00	1,426.50	5
Hard Coal old 1	171.84	235.00	247.00	1
Conventional gas old 1	72.45	172.36	189.55	8
CCGT old 1	54.16	100.00	150.00	2
CCGT new	635.96	1,130.00	1,363.00	6
OCGT new	25.59	83.00	91.77	2
Run-of-river (turbine)	978.31	2,294.74	2,419.01	45
Pump Storage Annual Reservoir (turbine)	45.00	101.50	114.32	2
Pump Storage & Storage / Weekly reservoir (turbine)	80.00	123.53	130.16	3
Swell RoR and Daily Storage (turbine)	0.00	0.00	0.00	0
Wind Onshore	1,000.98	3,513.10	3,697.93	44
Solar (Photovoltaic)	0.00	0.00	0.00	0
Others renewable	106.80	285.92	317.69	17
Total	**6,172.51**	**11,355.15**	**12,546.93**	**138**

As result of this different generation pattern, the total values related to this area are changed. A summary of the area totals, as reported from PSS®E, is shown in *Table 169*.

Table 169: Area summary of RO power system in minimum load 2030 regime, variant Referent RES

X-- AREA --X	FROM GENE-RATION	AT AREA BUSES FROM IND GENERATN	AT AREA BUSES TO IND MOTORS	AT AREA BUSES 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
44	6173.0	0.0	0.0	5193.5	0.0	0.0	87.6	0.0	141.6	750.4	750.4	750.0
RO	-423.5	0.0	0.0	1677.1	2094.9	0.0	207.5	5572.4	1738.7	-569.3	-569.3	

Due to the different generation pattern, the value of active power losses is changed, to 229,2 MW, compared to 196 MW in the referent RES scenario. In this regime, Transelectrica exports 750 MW to the neighboring systems, compared to the 350 MW in the referent RES scenario.

8.2.10. EMS models (RS)

In the year 2030, EMS expects its transmission system to have 33 tie-lines at these voltage levels:

- 14 tie-lines of voltage level 400 kV
- 4 tie-lines of voltage level 220 kV
- 15 tie-line of voltage level 110 kV

The elements used to model the power system of RS in 2030 are shown in *Table 170*.

Table 170: Number of elements in models of RS in 2030

1200 BUSES	87 PLANTS	91 MACHINES	0 INDUCTION GENS	0 INDUCTION MOTORS
355 LOADS	0 FIXED SHUNTS	0 SWITCHED SHUNTS		
1368 BRANCHES	715 TRANSFORMERS	0 DC LINES	0 FACTS DEVICES	0 GNE DEVICES

We show the expected installed generation capacities in the RS power system in 2030 in *Table 171*. This table shows the total maximum active power output; total rated apparent power; and the number of generation units. The data are given for each type of unit (fuel/technology type) and the last row shows the sum of all data in the corresponding column.

Table 171: Installed generation capacities in 2030 in the RS power system

Unit (fuel) type	Referent RES			High RES		
	Total P_{max} (MW)	Total S_n (MVA)	Number of units	Total P_{max} (MW)	Total S_n (MVA)	Number of units
Lignite old 1	4,874.60	5,619.80	14	4,874.60	5,619.80	14
CCGT NEW	437.90	579.00	5	437.90	579.00	5
Run-of-river (turbine)	2,092.94	2,250.50	29	2,092.94	2,250.50	29
Pump Storage Annual Reservoir (pump)	-560.00	630.00	2	-560.00	630.00	2
Pump Storage Annual Reservoir (turbine)	1,008.30	1,063.75	19	1,008.30	1,063.75	19
WIND ONSHORE	3,009.75	3,299.42	28	**3,708.84**	**4,124.28**	28
Total	**10,863.49**	**13,442.47**	**97**	**11,562.58**	**14,267.33**	**97**

The right side of the table shows the data used for the High RES variant, and the differences compared to the Referent RES are shown in red. It can be seen that the variant with High RES does not include additional WPPs, only additional installed capacity.

We show the loading of branches in the RS transmission grid in *Figure 283*, for branches of voltage levels of 110 kV and above.

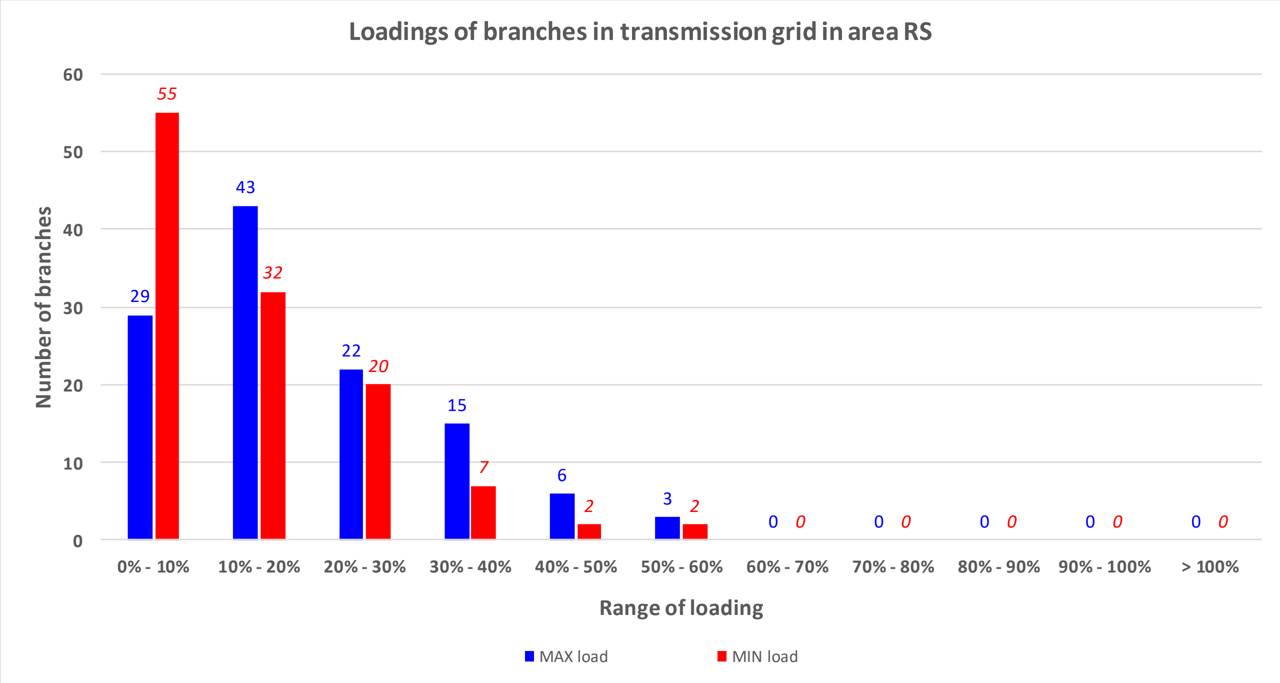


Figure 283: Histogram of branch loading in expected maximum and minimum regimes in 2030 in transmission grid of RS

From the figure, we see that there are no overloaded branches in the RS transmission grid, and that most elements are loaded below 30%. During the maximum load regime, there are 3 branches with a loading of 50% – 60%.

During the minimum load regime, almost all the elements have loadings below 40%. There are two branches with a loading of 40% – 50% and two branches with a loading of 50% – 60%.

Maximum load regime

We show the summary of area totals, as reported from PSS®E, for the maximum load 2030 regime in the Referent RES variant in *Table 172*. The first row represents data related to active power (in MW), while the second row shows data related to reactive power (in MVar).

Table 172: Area summary of RS power system in maximum load 2030 regime, variant Referent 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	TO TIES + LOADS	DESIRED NET INT
46	8437.8	0.0	0.0	6782.0	0.0	0.0	30.2	0.0	175.7	1450.0	1450.0	1450.0
RS	1146.8	0.0	0.0	1374.3	0.0	0.0	176.9	1814.8	2248.3	-837.8	-837.8	

The total RS system load is 6.782 MW and 1.374,3 MVar, including auxiliary loads. The value of active power losses is around 205,9 MW, which is relatively around 3,04%, in comparison against total system active load. In this regime it is expected that EMS exports around 1450 MW to neighboring systems.

It should be noted that the counting of total losses includes all lines and transformers in this power system, including step up transformers and transformers to the distribution network (if any).

We show the RS system summary per voltage level in *Table 173*. For each voltage level, this table shows assigned total active and reactive power losses, as well as the part of these losses which resulted from line shunts (i.e. transformer magnetizing losses). The last column shows reactive power generated by line chargings.

Table 173: Summary per voltage levels in the RS power system for maximum load 2030, variant with Referent RES

VOLTAGE LEVEL	BRANCHES	LOSSES MW	LOSSES MVAR	LINE SHUNTS MW	LINE SHUNTS MVAR	CHARGING MVAR
400.0	64	45.73	503.95	0.0	0.0	1326.2
220.0	64	21.59	181.32	1.3	8.0	185.2
110.0	594	78.70	469.73	5.2	40.5	303.4
36.8	1	0.01	0.31	0.0	0.1	0.0
35.0	277	10.94	344.76	9.3	40.9	0.0
33.0	20	1.85	109.13	1.1	4.5	0.0
22.0	3	0.62	44.11	0.8	4.2	0.0
21.0	4	1.36	91.90	0.7	2.7	0.0
20.0	129	2.98	80.21	3.5	26.2	0.0
15.8	6	1.43	86.08	1.1	4.6	0.0
15.7	2	0.47	17.68	0.3	2.2	0.0
15.6	4	0.72	33.05	0.2	0.2	0.0
15.0	3	0.99	59.58	0.6	17.2	0.0
11.0	11	1.82	51.26	0.6	4.7	0.0
10.5	5	0.58	15.58	0.2	1.3	0.0
10.0	103	3.05	98.41	3.2	11.0	0.0
8.8	4	0.19	3.65	0.1	0.5	0.0
6.9	4	0.03	0.30	0.1	0.9	0.0
6.3	19	1.36	32.42	0.5	2.1	0.0
6.0	51	1.25	24.87	1.2	4.1	0.0
TOTAL	1368	175.68	2248.29	30.0	176.0	1814.8

From this table, it can be seen that most of the active power losses of 44,8% is allocated in the 110 kV system, while the losses in the HV grid are responsible for 83,1% of total system losses.

We show the level of active power generation in the RS power system, in the maximum load regime for 2030, using Referent RES, *Table 174*. This table shows data per unit type (fuel/technology type) as well as the sum of all the data in corresponding columns, for operating units. It should be noted that this data shows output from generation units (values on transmission level must be decreased by auxiliary loads and losses in step up transformers).

The data include total active power generation and total maximum available active power, so we can estimate the active power reserve. In addition, we show the total rated apparent power, so we can also estimate reactive power levels. Finally, each row shows the number of units in operation, and those that are overloaded.

Table 174: Active power generation in RS power system, maximum load regime, for 2030, Referent RES Case

Fuel type	Total P_{gen} (MW)	Total P_{max} (MW)	Total S_n (MVA)	Number of units
Lignite old 1	3,155.00	4,089.90	4,705.30	11
CCGT NEW	437.90	437.90	579.00	5
Run-of-river (turbine)	1,429.19	2,092.94	2,250.50	29
Pump Storage Annual Reservoir (pump)	0.00	0.00	0.00	0
Pump Storage Annual Reservoir (turbine)	496.00	701.30	748.75	18
WIND ONSHORE	2,919.75	3,009.75	3,299.42	28
Total	**8,437.84**	**10,331.79**	**11,582.97**	**91**

This table shows that in the maximum load regime, there are 91 units in operation.

In the case of the High RES scenario, a different generation pattern is defined. Generation per fuel type is shown in *Table 175*. From the table it can be seen that the differences are significant, in comparison to the Referent RES scenario.

Table 175: Active power generation in RS power system, maximum load regime, for 2030, High RES Case

Fuel type	Total P_{gen} (MW)	Total P_{max} (MW)	Total S_n (MVA)	Number of units
Lignite old 1	3,155.00	4,089.90	4,705.30	11
CCGT NEW	437.90	437.90	579.00	5
Run-of-river (turbine)	1,585.36	2,092.94	2,250.50	29
Pump Storage Annual Reservoir (pump)	0.00	0.00	0.00	0
Pump Storage Annual Reservoir (turbine)	496.00	701.30	748.75	18
WIND ONSHORE	2,769.75	3,708.84	4,124.28	28
Total	**8,444.01**	**11,030.88**	**12,407.83**	**91**

As result of this different generation pattern, total values related to this area are not changed. Summary of area totals, as report from PSS®E, in shown in *Table 176*.

Table 176: Area summary of GR power system in maximum load 2030 regime, variant Referent RES

```
                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

  46           8444.0      0.0      0.0   6782.0      0.0      0.0     30.1      0.0   181.9    1450.0    1450.0   1450.0
RS             1224.7      0.0      0.0   1374.3      0.0      0.0    176.5   1810.1  2321.4    -837.4    -837.4
```

Due to different generation pattern the value of active power losses is changed, 212 MW compared to the 205,9 MW in referent RES scenario.

Minimum load regime

We show a summary of area totals, as reported from PSS®E, for the minimum load 2030 regime in the Referent RES case in *Table 177*. The first row represents data related to active power (in MW), while the second row shows data related to reactive power (in MVar).

Table 177: Area summary of RS power system in minimum load 2030 regime, variant Referent RES

```
                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

  46           3990.8      0.0      0.0   2663.5      0.0      0.0     31.9      0.0    95.5    1200.0    1200.0   1200.0
RS             -352.5      0.0      0.0    785.3      0.0      0.0    130.0   1911.7  1117.1    -473.2    -473.2
```

The total RS system load is 2.663,5 MW and 785,3 MVar, including auxiliary loads, so the total system active load is 39,3% of the maximum load. Value of active power losses is around 127,4 MW, which is around 4,78%of the total system active load. In this regime we would expect EMS to export 1200 MW to the neighboring systems.

It should be noted that counting of total losses include all lines and transformers in this power system, including step up transformers and transformers to distribution network (if any).

We show the RS system summary for each voltage level in *Table 178*, including the total active and reactive power losses, and the share of losses from line shunts (i.e., transformer magnetizing losses). The final column shows the reactive power generated by line chargings.

Table 178: Summary per voltage levels in the RS power system for minimum load 2030, variant with Referent RES

VOLTAGE LEVEL	BRANCHES	LOSSES MW	LOSSES MVAR	LINE SHUNTS MW	LINE SHUNTS MVAR	CHARGING MVAR
400.0	64	28.75	319.07	0.0	0.0	1380.0
220.0	64	15.35	132.24	1.4	6.8	196.7
110.0	594	39.15	163.95	5.5	17.2	335.0
36.8	1	0.01	0.29	0.0	0.0	0.0
35.0	277	4.31	160.74	10.2	38.3	0.0
33.0	20	1.35	80.41	1.2	4.2	0.0
22.0	2	0.43	29.99	0.5	3.2	0.0
21.0	4	0.61	44.84	0.7	2.7	0.0
20.0	129	0.47	11.45	3.9	20.7	0.0
15.8	6	0.37	16.89	1.1	4.2	0.0
15.6	4	0.03	1.58	0.2	0.2	0.0
15.0	2	0.29	18.24	0.5	5.8	0.0
11.0	11	2.34	85.22	0.6	4.8	0.0
10.5	5	0.00	0.00	0.2	1.4	0.0
10.0	103	0.50	19.26	3.6	12.0	0.0
8.8	4	0.02	0.44	0.1	0.5	0.0
6.9	4	0.03	0.29	0.1	0.9	0.0
6.3	19	0.37	11.52	0.5	2.3	0.0
6.0	51	1.10	20.71	1.3	4.5	0.0
TOTAL	1364	95.50	1117.13	31.6	129.7	1911.7

From this table it can be seen that the most part of active power losses 41% is allocated in 110 kV, while losses in HV grid participate with 87,2% in total system losses.

We show active power generation in the RS power system, in the minimum load regime for 2030, Referent RES case, in *Table 179*. This table shows the data per unit type (fuel/technology type) as well as the sum of all data in corresponding columns, for units in operation. This data shows the output from generation units (values on the transmission level must be decreased by auxiliary loads and losses in step-up transformers).

The data include total active power generation and total maximum available active power, so we can estimate the active power reserve. In addition, we show the total rated apparent power, and can thus estimate reactive power possibilities. Finally, each row contains the number of units in operation.

Table 179: Active power generation in RS power system, minimum load regime, year 2030, Referent RES Case

Fuel type	Total P_{gen} (MW)	Total P_{max} (MW)	Total S_n (MVA)	Number of units
Lignite old 1	1,665.00	2,193.50	2,564.80	6
CCGT NEW	187.90	187.90	235.00	3
Run-of-river (turbine)	264.10	539.79	586.00	11
Pump Storage Annual Reservoir (pump)	-560.00	-560.00	630.00	2
Pump Storage Annual Reservoir (turbine)	0.00	0.00	0.00	0
WIND ONSHORE	2,433.80	3,009.75	3,299.42	28
Total	**3,990.80**	**5,370.94**	**7,315.22**	**50**

We see that in the minimum load regime, there are 50 units in operation.

In case of High RES scenario, generation pattern is the same as in Referent RES scenario, so the only difference in models is in installed capacities of additional RES.

8.2.11. ELES models (SI)

In the year 2030, ELES expects its transmission system to have 15 tie-lines at these voltage levels:

- 8 tie-lines of voltage level 400 kV
- 4 tie-lines of voltage level 220 kV
- 3 tie-line of voltage level 110 kV

The elements used to model the power system of SI in 2030 are shown in Table 180.

Table 180: Number of elements in models of SI in 2030

```
   232 BUSES          60 PLANTS           85 MACHINES        0 INDUCTION GENS       0 INDUCTION MOTORS
   191 LOADS           0 FIXED SHUNTS      2 SWITCHED SHUNTS
   352 BRANCHES       83 TRANSFORMERS      0 DC LINES        0 FACTS DEVICES        0 GNE DEVICES
```

We show the expected installed generation capacities in the SI power system in 2030 in Table 181. This table shows the total maximum active power output; total rated apparent power; and the number of generation units. The data are given for each type of unit (fuel/technology type) and the last row shows the sum of all data in the corresponding column.

Table 181: Installed generation capacities in 2030 in the SI power system

Unit (fuel) type	Referent RES			High RES		
	Total P_{max} (MW)	Total S_n (MVA)	Number of units	Total P_{max} (MW)	Total S_n (MVA)	Number of units
NUCLEAR	730.00	813.00	1	730.00	813.00	1
Lignite old 2	599.00	727.00	1	599.00	727.00	1
CCGT NEW	139.00	173.75	3	139.00	173.75	3
OCGT OLD	371.00	458.44	5	371.00	458.44	5
OCGT NEW	50.00	66.78	1	50.00	66.78	1
Run-of-river (turbine)	1,246.85	1,453.40	63	1,246.85	1,453.40	63
Pump Storage / Daily reservoir (pump)	-180.00	196.81	1	-180.00	196.81	1
Pump Storage / Daily reservoir (turbine)	185.00	196.81	1	185.00	196.81	1
WIND ONSHORE	10.00	10.53	1	**150.00**	**157.90**	1
Solar (Photovoltaic)	0.00	700.00	7	0.00	700.00	7
Hard Coal biofuel	46.00	62.50	1	46.00	62.50	1
Total	**3,196.85**	**4,859.02**	**85**	**3,336.85**	**5,006.39**	**85**

The right side of the table shows the data used for the High RES variant, and the differences compared to the Referent RES are shown in red. It can be seen that the variant with High RES does not include additional WPPs or SPP, only additional installed capacity.

We show the loading of branches in the SI transmission grid in Figure 284, for branches of voltage levels of 110 kV and above.

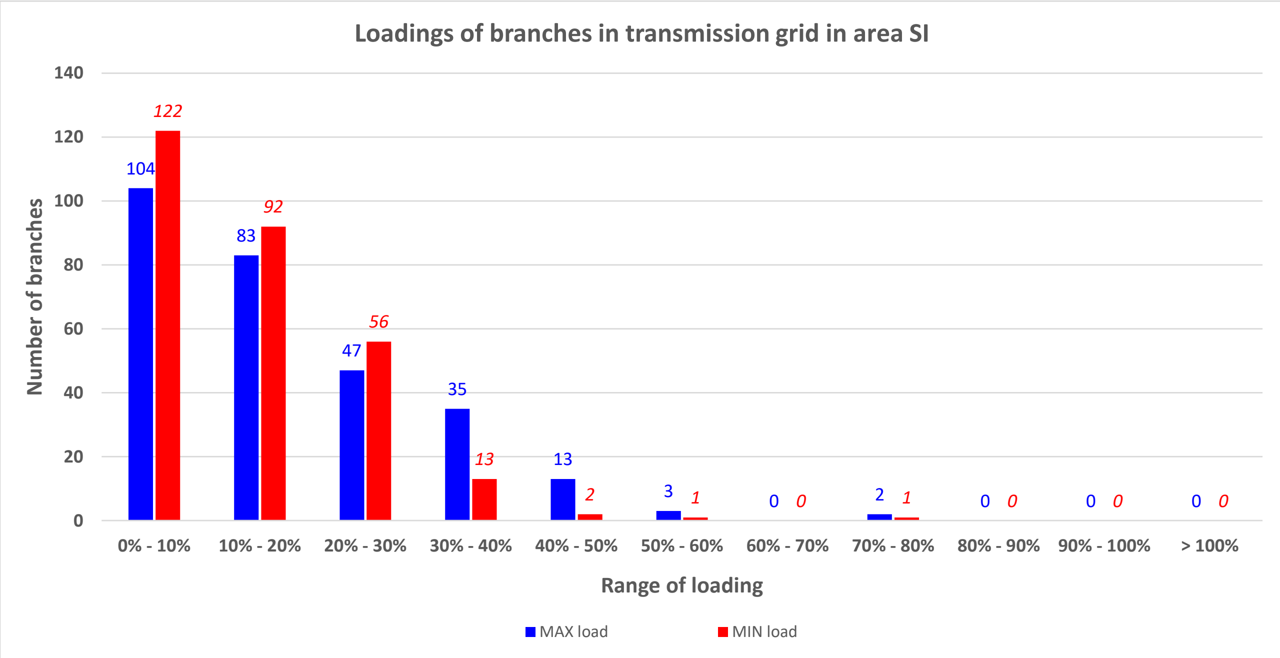


Figure 284: Histogram of branch loading in expected maximum and minimum regimes in 2030 in transmission grid of SI

From the figure, we see that there are no overloaded branches in the SI transmission grid, and that most elements are loaded below 30%. During the maximum load regime, there are 5 branches loaded over 50%, and two have loadings of 70% – 80%.

During the minimum load regime, almost all the elements have loadings below 40%. There is just one branch with a loading of 70% – 80% and one branch with a loading of 50% – 60%.

Maximum load regime

We show the summary of area totals, as reported from PSS®E, for the maximum load 2030 regime in the Referent RES variant in *Table 182*. The first row represents data related to active power (in MW), while the second row shows data related to reactive power (in MVar).

Table 182: Area summary of SI power system in maximum load 2030 regime, variant Referent RES

X-- AREA --X	FROM GENE-RATION	AT AREA BUSES FROM IND GENERATN	AT AREA BUSES TO IND MOTORS	AT AREA BUSES 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
49	2069.8	0.0	0.0	2228.1	0.0	0.0	7.6	0.0	43.9	-209.8	-209.8	-210.0
SI	118.0	0.0	0.0	354.3	0.0	0.0	49.3	513.6	619.0	-391.0	-391.0	

The total SI system load is 2.228,1 MW and 354,3 MVar, including auxiliary loads. The value of active power losses is around 51,5 MW, which is relatively around 2,31%, in comparison against total system active load. In this regime it is expected that ELES imports around 210 MW from neighboring systems.

It should be noted that counting of total losses include all lines and transformers in this power system, including step up transformers and transformers to distribution network (if any).

We show the SI system summary per voltage level in *Table 183*. For each voltage level this table shows assigned total active and reactive power losses as well as part of this losses which resulted from line shunts (i.e. transformer magnetizing losses). Last column shows reactive power generated by line chargings.

Table 183: Summary per voltage levels in the SI power system for maximum load 2030, variant with Referent RES

```
VOLTAGE        X----- LOSSES -----X   X-- LINE SHUNTS --X   CHARGING
 LEVEL BRANCHES        MW        MVAR        MW        MVAR        MVAR
 400.0      15      17.19      309.46       0.3        0.8       325.2
 220.0       8       7.26       53.45       0.3        2.0        34.2
 110.0     269      16.01      115.43       3.8       25.2       154.2
  21.0       3       1.84      103.13       0.7        8.8         0.0
  18.0       1       0.00        0.00       0.1        0.1         0.0
  10.5      39       1.16       27.65       1.9        9.3         0.0
   6.3      17       0.42        9.88       0.5        3.2         0.0
 TOTAL     352      43.88      619.00       7.6       49.3       513.6
```

From this table it can be seen that the most part of active power losses 36,5% is allocated in 110 kV, while losses in HV grid participate with 92,2% in total system losses.

We show the level of active power generation in the SI power system, in the maximum load regime for 2030, using Referent RES, in *Table 184*. This table shows data per unit type (fuel/technology type) as well as the sum of all the data in corresponding columns, for operating units. It should be noted that this data shows output from generation units (values on transmission level must be decreased by auxiliary loads and losses in step up transformers).

The data include total active power generation and total maximum available active power, so we can estimate the active power reserve. In addition, we show total rated apparent power, so we can also estimate reactive power levels. Finally, each row shows the number of units in operation, and those that are overloaded.

Table 184: Active power generation in SI power system, maximum load regime, for 2030, Referent RES Case

Fuel type	Total P_{gen} (MW)	Total P_{max} (MW)	Total S_n (MVA)	Number of units
NUCLEAR	730.15	730.00	813.00	1
Lignite old 2	576.00	599.00	727.00	1
CCGT NEW	45.80	139.00	173.75	3
OCGT OLD	0.00	371.00	458.44	5
OCGT NEW	0.00	50.00	66.78	1
Run-of-river (turbine)	685.30	1,248.15	1,453.40	63
Pump Storage / Daily reservoir (pump)	0.00	-180.00	196.81	1
Pump Storage / Daily reservoir (turbine)	0.00	185.00	196.81	1
WIND ONSHORE	0.00	10.00	10.53	1
Solar (Photovoltaic)	0.00	0.00	700.00	7
Hard Coal biofuel	32.60	46.00	62.50	1
Total	**2,069.85**	**3,198.15**	**4,859.02**	**85**

This table shows that in the maximum load regime, there are 85 units in operation.

In case of High RES scenario, generation pattern is the same as in Referent RES scenario, so the only difference in models is in installed capacities of additional RES.

Minimum load regime

We show a summary of area totals, as reported from PSS®E, for the minimum load 2030 regime in the Referent RES case in *Table 185*. The first row represents data related to active power (in MW), while the second row shows data related to reactive power (in MVar).

Table 185: Area summary of SI power system in minimum load 2030 regime, variant Referent 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
49	1683.6	0.0	0.0	1587.9	0.0	0.0	7.6	0.0	21.8	66.2	66.2	66.0
SI	-36.7	0.0	0.0	272.7	0.0	0.0	49.5	516.3	309.5	-152.1	-152.1	

The total system load is 1.587,9 MW and 272,7 MVar, including auxiliary loads, so the total system active load is 71,27% of the maximum load. Value of active power losses is around 29,4 MW, which is around 1,85% of the total system active load. In this regime, we would expect ELES to export 66 MW to the neighboring systems.

It should be noted that counting of total losses include all lines and transformers in this power system, including step up transformers and transformers to distribution network (if any).

We show the SI system summary for each voltage level in *Table 186*, including the total active and reactive power losses, and the share of losses from line shunts (i.e., transformer magnetizing losses). The final column shows the reactive power generated by line chargings.

Table 186: Summary per voltage levels in the SI power system for minimum load 2030, variant with Referent RES

VOLTAGE LEVEL	BRANCHES	LOSSES MW	LOSSES MVAR	LINE SHUNTS MW	LINE SHUNTS MVAR	CHARGING MVAR
400.0	15	5.61	98.08	0.3	0.8	326.9
220.0	8	0.69	7.99	0.3	2.0	34.2
110.0	269	11.39	64.06	3.8	25.3	155.2
21.0	3	1.37	71.51	0.7	8.8	0.0
18.0	1	0.34	18.06	0.1	0.1	0.0
10.5	39	1.81	36.54	1.9	9.3	0.0
6.3	17	0.60	13.28	0.5	3.2	0.0
TOTAL	352	21.81	309.52	7.6	49.5	516.3

From this table it can be seen that the most part of active power losses 52,2% is allocated in 110 kV, while losses in HV grid participate with 81,1% in total system losses.

We show active power generation in the SI power system, in the minimum load regime for 2030, Referent RES case, in *Table 187*. This table shows the data per unit type (fuel/technology type) as well as the sum of all data in corresponding columns, for units in operation. This data shows the output from generation units (values on the transmission level must be decreased by auxiliary loads and losses in step-up transformers).

The data include total active power generation and total maximum available active power, so we can estimate active power reserve. In addition, we show the total rated apparent power, and can thus estimate reactive power possibilities. Finally, each row contains the number of units in operation as well as number of units which are slightly overloaded.

Table 187: Active power generation in SI power system, minimum load regime, year 2030, Referent RES Case

Fuel type	Total P_{gen} (MW)	Total P_{max} (MW)	Total S_n (MVA)	Number of units
NUCLEAR	733.17	730.00	813.00	1
Lignite old 2	267.20	599.00	727.00	1
CCGT NEW	33.00	139.00	173.75	3
OCGT OLD	0.10	371.00	458.44	5
OCGT NEW	0.00	50.00	66.78	1
Run-of-river (turbine)	797.90	1,246.85	1,453.40	63
Pump Storage / Daily reservoir (pump)	-171.00	-180.00	196.81	1
Pump Storage / Daily reservoir (turbine)	0.00	185.00	196.81	1
WIND ONSHORE	0.00	10.00	10.53	1
Solar (Photovoltaic)	0.00	0.00	700.00	7
Hard Coal biofuel	23.20	46.00	62.50	1
Total	**1,683.57**	**3,196.85**	**4,859.02**	**85**

We see that in the minimum load regime, there are 85 units in operation.

In case of High RES scenario, generation pattern is the same as in Referent RES scenario, so the only difference in models is in installed capacities of additional RES.

8.3. Summary of SEE regional grid models

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

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

We created the regional models by merging all the collected national models. The number of elements in the regional models are shown in *Table 188*.

Table 188: Number of elements in the regional models

8491 BUSES	1462 PLANTS	1230 MACHINES	0 INDUCTION GENS	0 INDUCTION MOTORS
3416 LOADS	277 FIXED SHUNTS	150 SWITCHED SHUNTS		
9736 BRANCHES	3653 TRANSFORMERS	2 DC LINES	1 FACTS DEVICES	0 GNE DEVICES

Beside summary per each area and analysis of voltage profile, for each regional model, assessment of steady-state security against single outages has been made. This assessment included analyses of grid conditions in case of single outage of branches with regional importance. Following branches have been included in list of outages as well as in list of monitoring elements:

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

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

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

8.3.1. Maximum load regime – 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 189: Summaries of all areas in regional model – maximum load 2030, referent RES

X-- AREA --X	FROM GENE-RATION	AT AREA BUSES: FROM IND GENERATN	AT AREA BUSES: TO IND MOTORS	AT AREA BUSES: 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	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 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 190: 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.

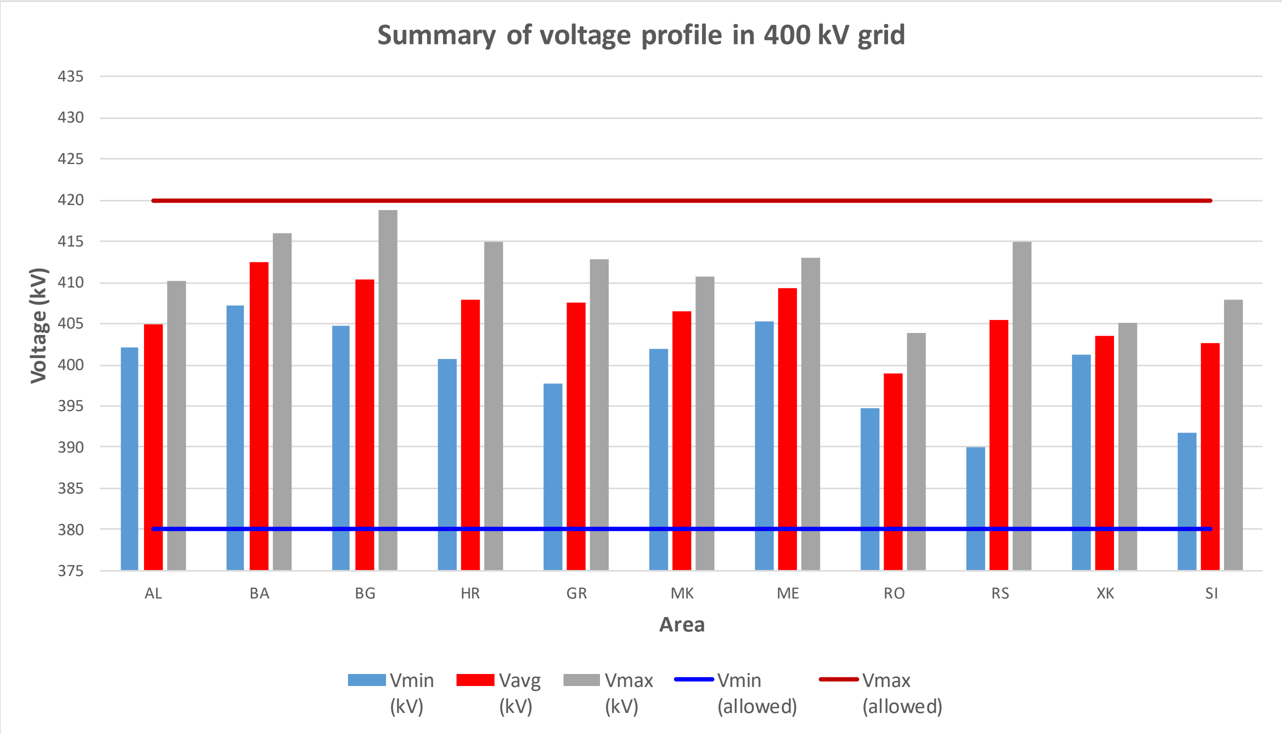


Figure 285: Summary of the voltage profile in the 400 kV grid – maximum load 2030, referent RES

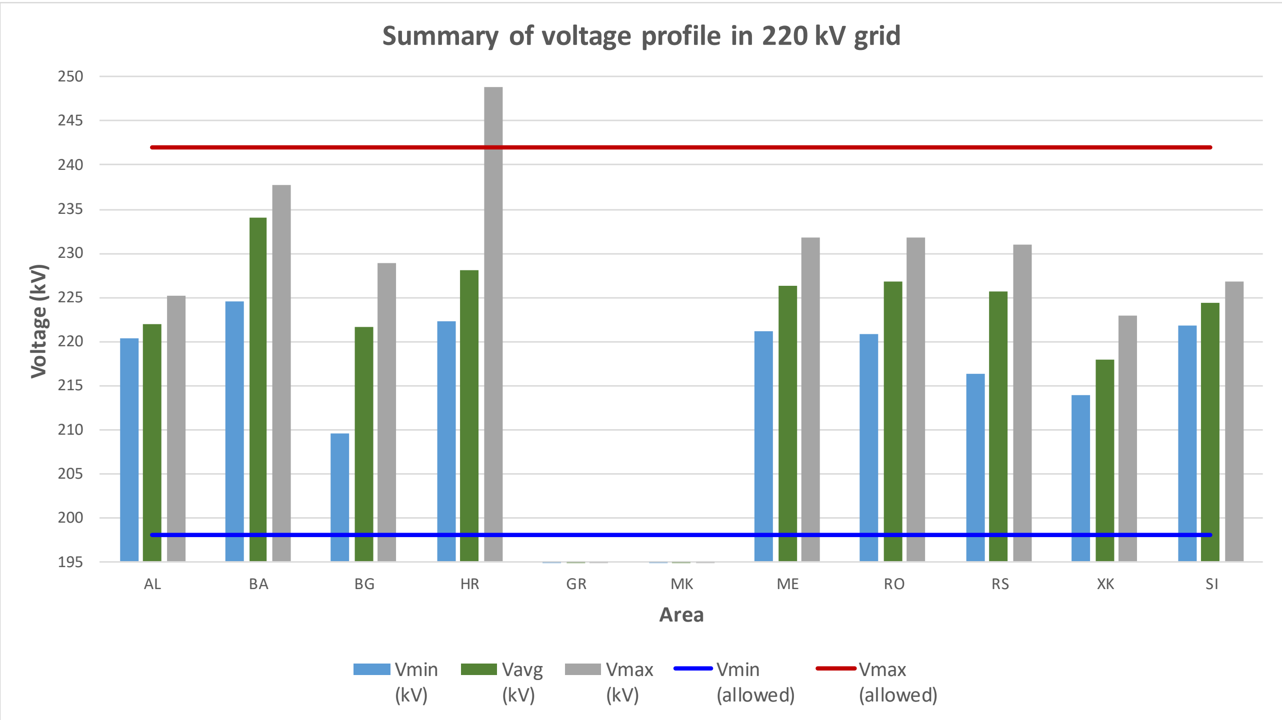


Figure 286: Summary of voltage profile in 220 kV grid – maximum load 2030, referent RES

It can be seen that voltages in the 400 kV grid are within allowed limits. However, in the 220 kV grid, HOPS (HR) has nodes 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.

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

Figure 287: Aggregated border exchanges – maximum load 2030, referent RES

Aggregated border exchanges are shown in arrows. Direction of arrows is fixed and values inside can be positive and negative. Negative value means that aggregated border active power flow has opposite direction then the arrow shows. Bellow 2-character ISO code for each area/country there is TSO balance, which represent total import/export as sum of all aggregated border power flows from corresponding TSO.

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

8.3.2. Maximum load regime – high RES

We provide a summary of 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 191: 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 numbers of nodes in operation, minimum voltage, maximum voltage, and average voltage levels.

Table 192: 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.

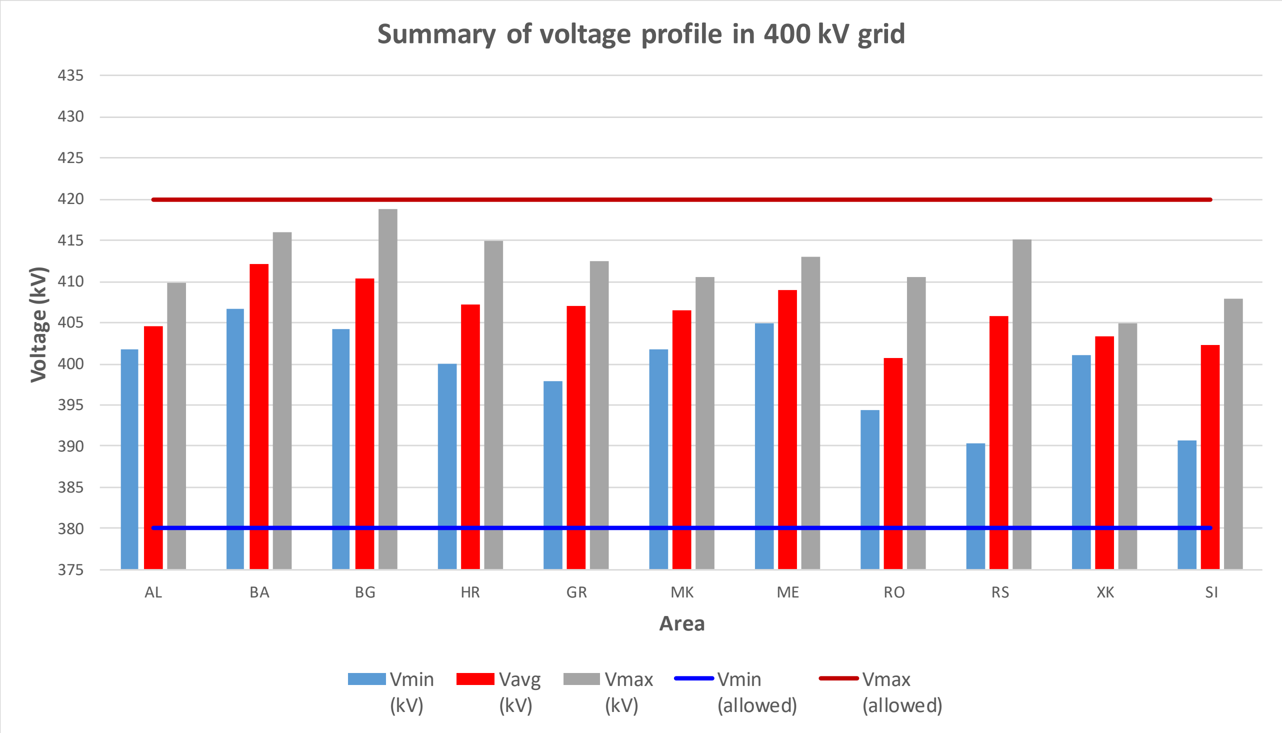


Figure 288: Summary of voltage profile in 400 kV grid – maximum load 2030, high RES

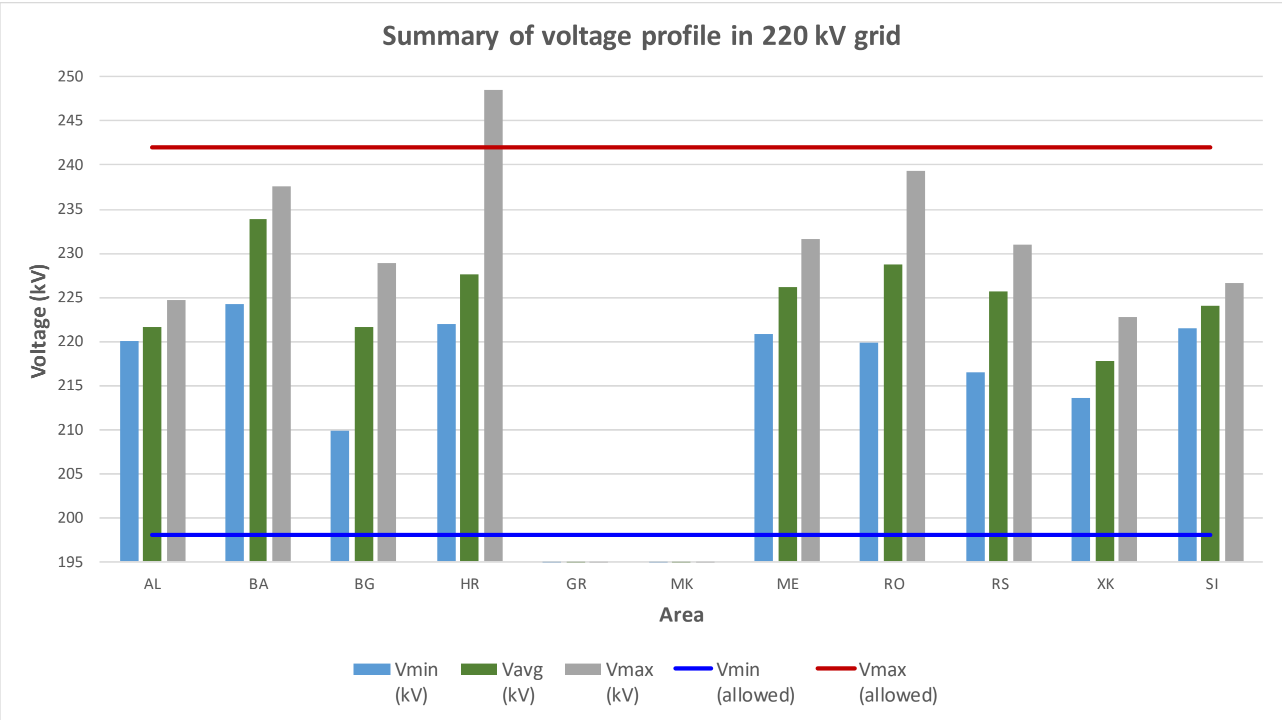


Figure 289: Summary of voltage profile in 220 kV grid – maximum load 2030, high RES

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 290: Aggregated border exchanges – maximum load 2030, high RES

Aggregated border exchanges are shown in arrows. Negative value means that aggregated border active power flow has opposite direction then the arrow shows. Bellow 2-character ISO code for each area/country there is TSO balance, which represent total import/export as sum of all aggregated border power flows from corresponding TSO.

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

8.3.3. 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 193: Summaries of all areas in regional model – minimum load 2030, referent 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	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 corresponding data from the national/TSO models, 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 400 kV as well as 220 kV (if exists). For each system and voltage level, we show the numbers of nodes in operation, along with the maximum, minimum and average voltage values.

Table 194: 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.

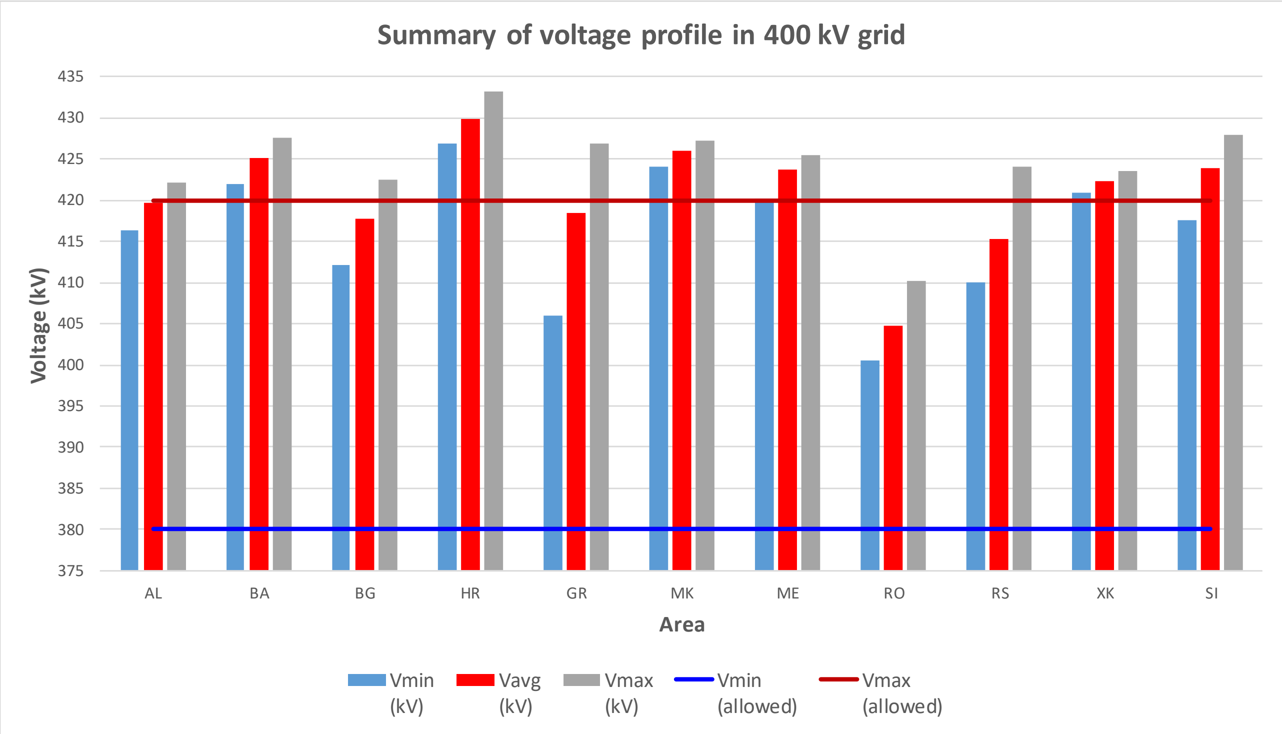


Figure 291: Summary of voltage profile in 400 kV grid – minimum load 2030, referent RES

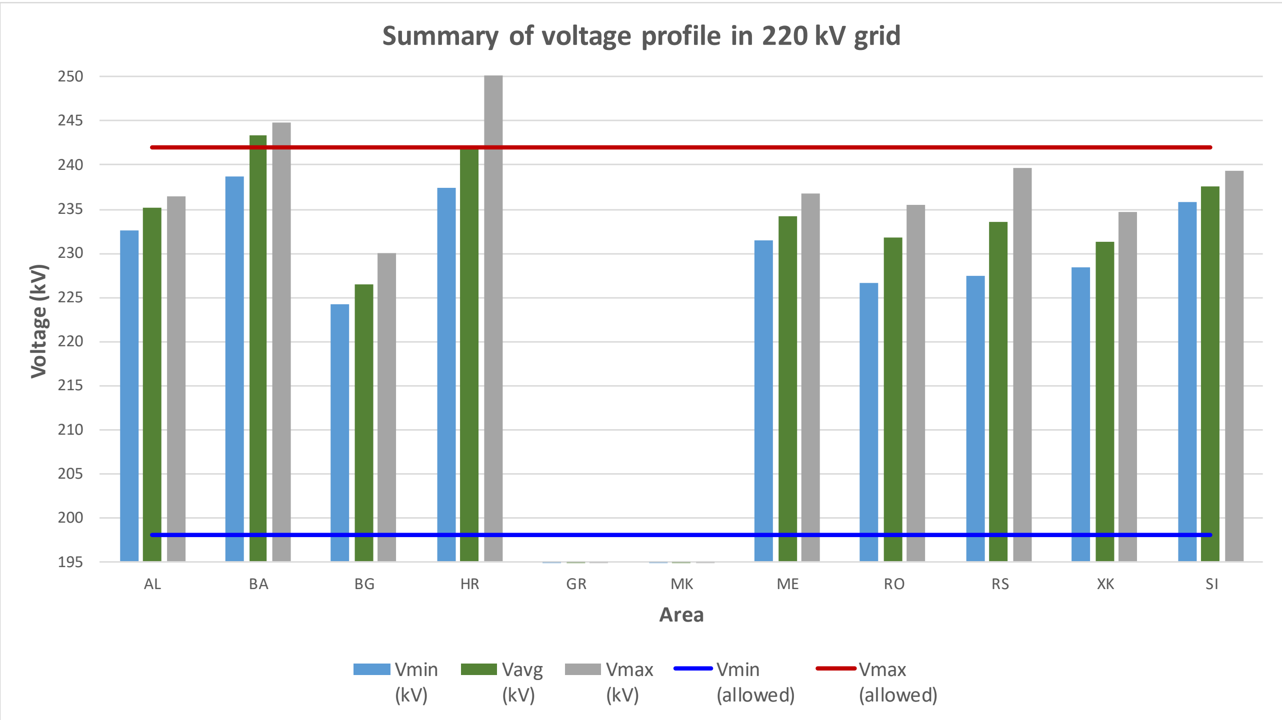


Figure 292: Summary of voltage profile in 220 kV grid – minimum load 2030, referent RES

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 average values are above the allowed maximum limit.

Situation is a 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.

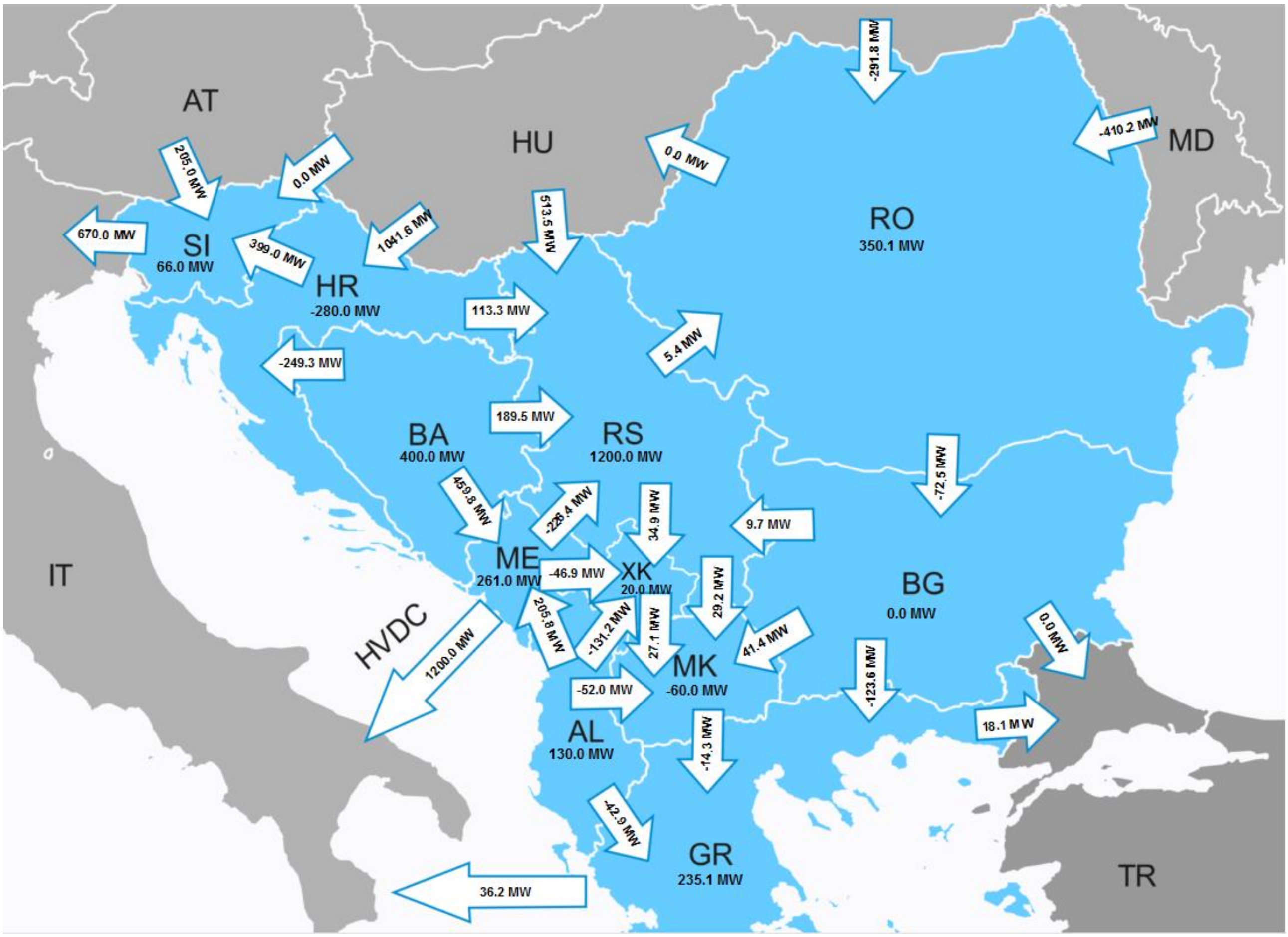


Figure 293: Aggregated border exchanges – minimum load 2030, referent RES

Aggregated border exchanges are shown in arrows. Negative value means that aggregated border active power flow has opposite direction then the arrow shows. Bellow 2-character ISO code for each area/country there is TSO balance, which represent total import/export as sum of all aggregated border power flows from corresponding TSO.

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

8.3.4. 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 195: Summaries of all areas in regional model – minimum 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	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 corresponding data from the national/TSO models, 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 400 kV as well as 220 kV (if exists). For each system and voltage level, we show the numbers of nodes in operation, along with the maximum, minimum and average voltage values.

Table 196: 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.

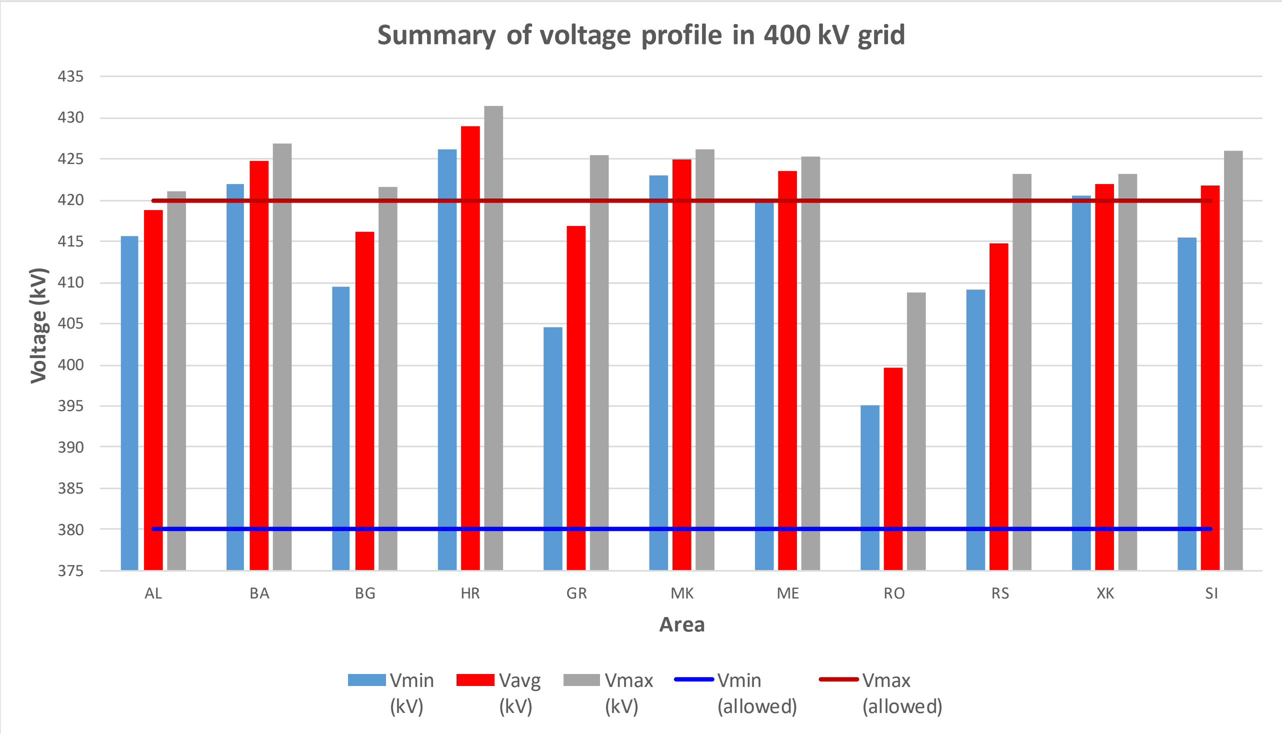


Figure 294: Summary of voltage profile in 400 kV grid – minimum load 2030, high RES

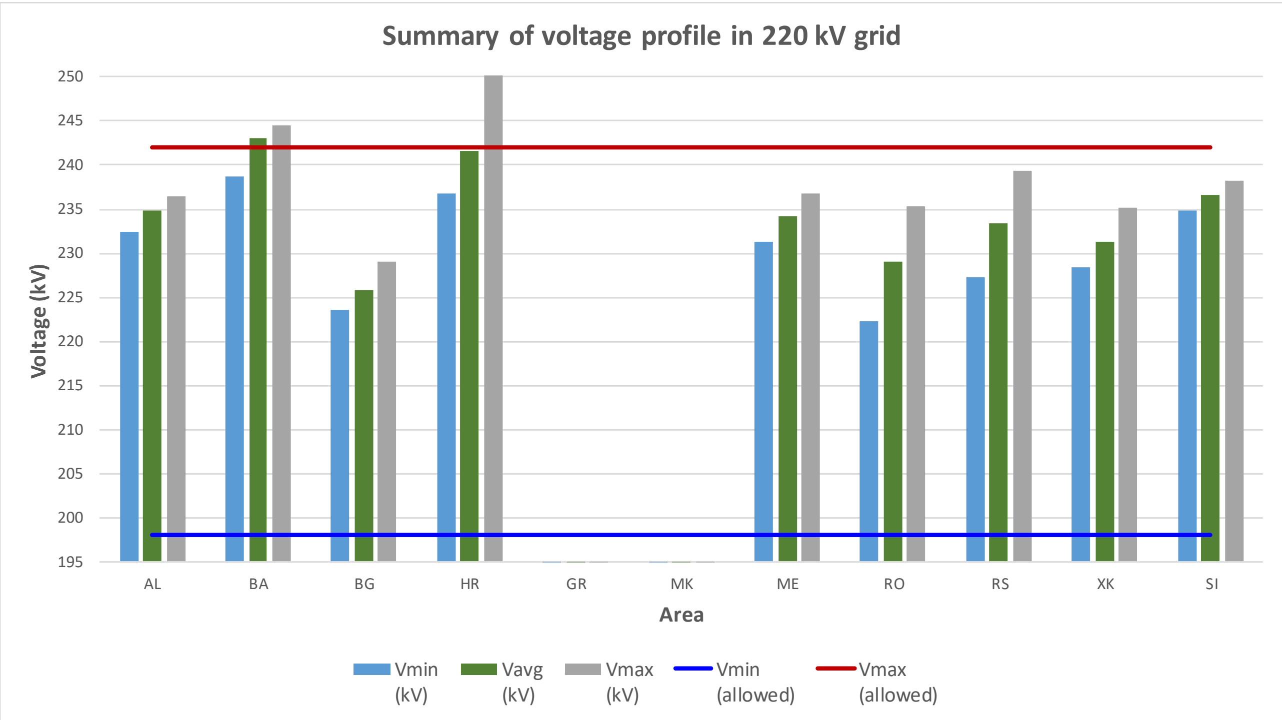


Figure 295: Summary of voltage profile in 220 kV grid – minimum load 2030, high RES

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 allowed maximum limit.

Situation is a 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 296: Aggregated border exchanges – minimum load 2030, high RES

Aggregated border exchanges are shown in arrows. Negative value means that aggregated border active power flow has opposite direction then the arrow shows. Bellow 2-character ISO code for each area/country there is TSO balance, which represent total import/export as sum of all aggregated border power flows from corresponding TSO.

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

Table 197: 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
```

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

8.4. Level of modeling for grid analyses

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

- Complete transmission network at the voltage level of 110 kV and above
    - If there are parallel branches, we model each branch separately (i.e., we did not model parallel branches as one equivalent or aggregated branch)
- Every conventional generation unit connected to the transmission grid is modeled at the generation voltage level, and connected to the system through a step-up transformer
    - Where there are power plants with multiple conventional units, each unit is modeled separately (i.e., we did not model multiple generation units as one equivalent unit)
- Every wind and solar power plant connected to the transmission grid is modeled as one unit at the point of common coupling (PCC), where generation from all units are collected, and this "unit" is connected to the transmission grid through a step-up transformer
- There are no equivalents with regard to the network in the areas of the participating TSOs

8.4.1. Modeling of distributed generation

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

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

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

8.4.2. Modeling of tie-lines

For better organizing of reports and easier handling with models, each tie-line is modeled with fictitious node (so called *X-node* or *border node*) which is placed on geographical border between countries/TSOs as shown in the following figure.

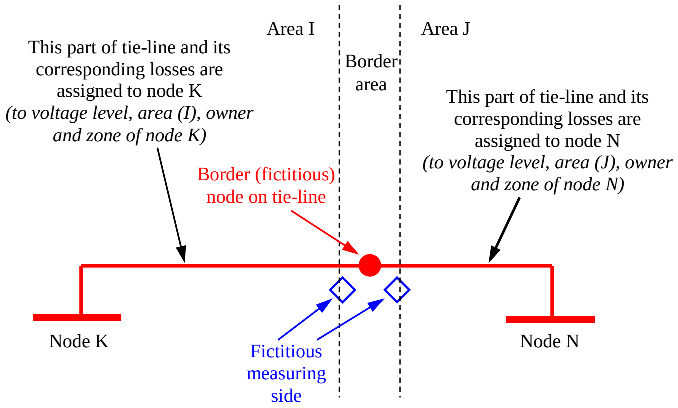


Figure 297: Modeling of tie-lines

Practically, each tie-line is divided in two parts. Each border node is assigned to fictitious border area and measuring point of each part of tie-line is placed on side of border node. With this approach losses in each part of tie-line is assigned to corresponding area.

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

On the other side, in case of tie-lines between EMI members and external system, these border nodes need to have some equivalent load which represent power exchange on corresponding tie-lines.

9. TABLE OF FIGURES

10. TABLE OF TABLES