ENERGY TECHNOLOGY AND GOVERNANCE PROGRAM

Assessment of the Impacts of Regional Electricity Market Integration in Southeast Europe

– Final Report –

ELECTRICITY MARKET INITIATIVE WORKING GROUP

November 25, 2019

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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Cooperative Agreement AID-OAA-A-12-00036

Prepared for:

United States Agency for International Development
and
United States Energy Association

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ABBREVIATIONS

CV	–	Coefficient of Variation
EEX	–	European Energy Exchange
EIHP	–	Energy Institute Hrvoje Požar
EKC	–	Electricity Coordinating Center
EMI	–	Electricity Market Initiative
ENS	–	Energy Not Served
EnCS	–	Energy Community Secretariat
EU	–	European Union
EU ETS	–	European Union Emissions Trading System
EXIST	–	Energy Exchange Istanbul
FMC	–	Full Market Coupling
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
MRC	–	Multi-Regional Coupling
NTC	–	Net Transfer Capacity
PEMDB	–	Pan-European Market Database (developed by ENTSO-E)
PMC	–	Partial Market Coupling
RES	–	Renewable Energy Sources
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 Countries
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
MEMO	–	Electricity Market Operator of North Macedonia
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

EXECUTIVE SUMMARY

One of the goals of the Electricity Market Initiative (EMI) is to work with the transmission system operators (TSOs) and market operators (MOs) to evaluate the possible benefits of accelerating the integration of and competition among electricity markets in the Western Balkans (WB6) and neighboring countries of Southeast Europe (SEE). Figure 1 below shows the region on which the EMI focuses, and the 15 current members in this program.

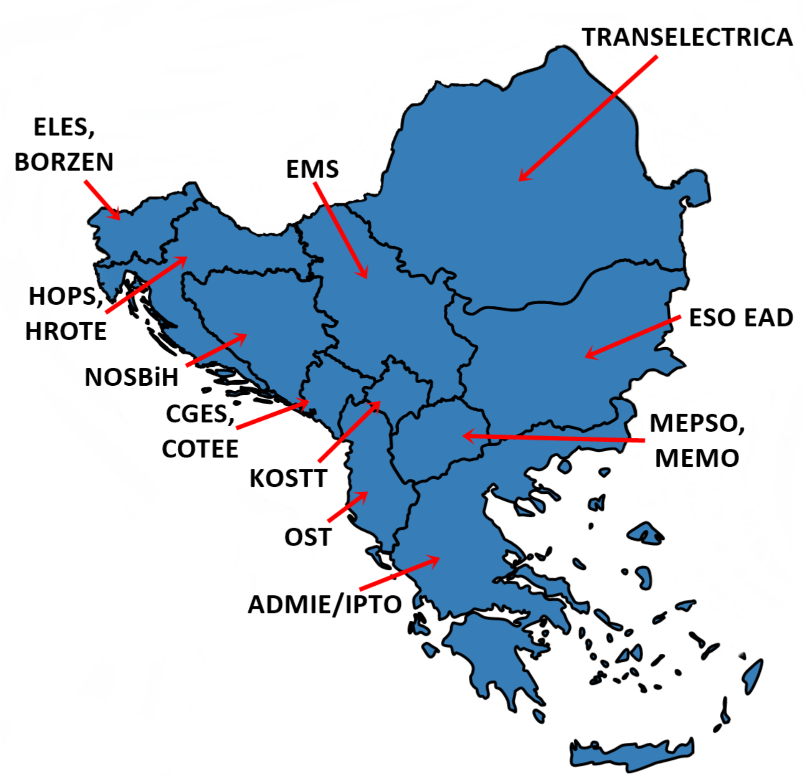


Figure 1: EMI Members

The objective of this task was to analyze and quantify the impacts of electricity market integration in the SEE region. In general, market integration can refer to electricity markets in different timeframes and products (futures, day-ahead, intraday, real time - balancing, reserves) but within this assignment, the focus is on the wholesale day-ahead electricity market.

It can be expected that the integration of relatively small electricity markets in the region, in conjunction with other changes, will produce a number of benefits, such as: raise the efficiency of regional generation and cross-border transmission resources compared to individual country dispatch; increase the size and liquidity of such markets; attract non-incumbents as well as existing utilities to make such markets more competitive; put downward pressure on wholesale prices; modify the generation mix (towards less polluting generation and more renewables or RES); and raise overall social-economic welfare (SEW).

To capture and project the impact of such integration, this work has utilized a complex regional electricity market model (called Antares) that includes all existing and planned generating capacities in SEE with a simplified representation of the transmission network. This analysis focused on the year 2025, and the team carried out hourly simulations of the power system operation in order to produce results for each hour.

This model performed analyses of market integration and quantified its impact on wholesale market prices, the allocation of generation and generation costs, and cross-border electricity exchange. We evaluated SEW separately. To capture these impacts, we agreed with the EMI members to test the impact on those factors under a range of market conditions, including combinations of the following:

- The level of coupling;
- The level of hydrology;
- The level of demand growth; and
- The level of RES penetration.

In specific, we looked at different scenarios for market coupling in conjunction with four sets of market conditions: a) baseline (normal hydro, expected demand, expected RES); b) dry hydro; c) high RES penetration plus low demand; and d) dry hydro, low demand and high RES penetration.

We have compiled and tested the Antares model, and will transfer it to the EMI participants for their internal purposes, with appropriate training. To summarize, the overall goals were twofold:

1) to determine the impacts on wholesale power costs and other market indicators as one expands the geography of the analysis from individual countries/market areas, to groupings or couplings of countries, and then to the entire SEE region; and
2) to develop a useful tool for the EMI participants to perform market analyses according to their internal needs.

For the WB6, couplings will happen in different time frames, and the region may not be fully integrated by 2025. Therefore, in consultation with the EMI members, we decided to analyze one intermediate step between the current state and full market integration, i.e., a partial market coupling scenario (Figure 2), or PMC, which assumes a lower level of market integration in the SEE region. Our PMC scenario, with four groups of power markets, is a basis for comparison of one scenario to another, and a way to quantify the impacts while the region is moving towards full integration. This scenario may also represent changes that could occur before 2025.

As depicted in Figure 2, this PMC scenario assumes four (4) groups of market couplings as follows:

- Market coupling of the NOSBiH, HOPS and ELES market areas,
- Market coupling of the CGES, Hungarian and EMS market areas,
- Market coupling of the OST and KOSTT market areas, and
- Market coupling of the ESO EAD, ADMIE/IPTO, MEPSO and TransElectrica market areas.

Given that we assume the market coupling of all EU member states in all scenarios, this partial market coupling scenario in fact enables coupling of almost all the EMI WG members with the Multi-Regional Coupling (MRC) project for pan-European market coupling, at least on one border. As mentioned, this is considered a transitional situation; in the full market coupling scenario, all EMI WG member borders are mutually coupled, and coupled with the MRC.

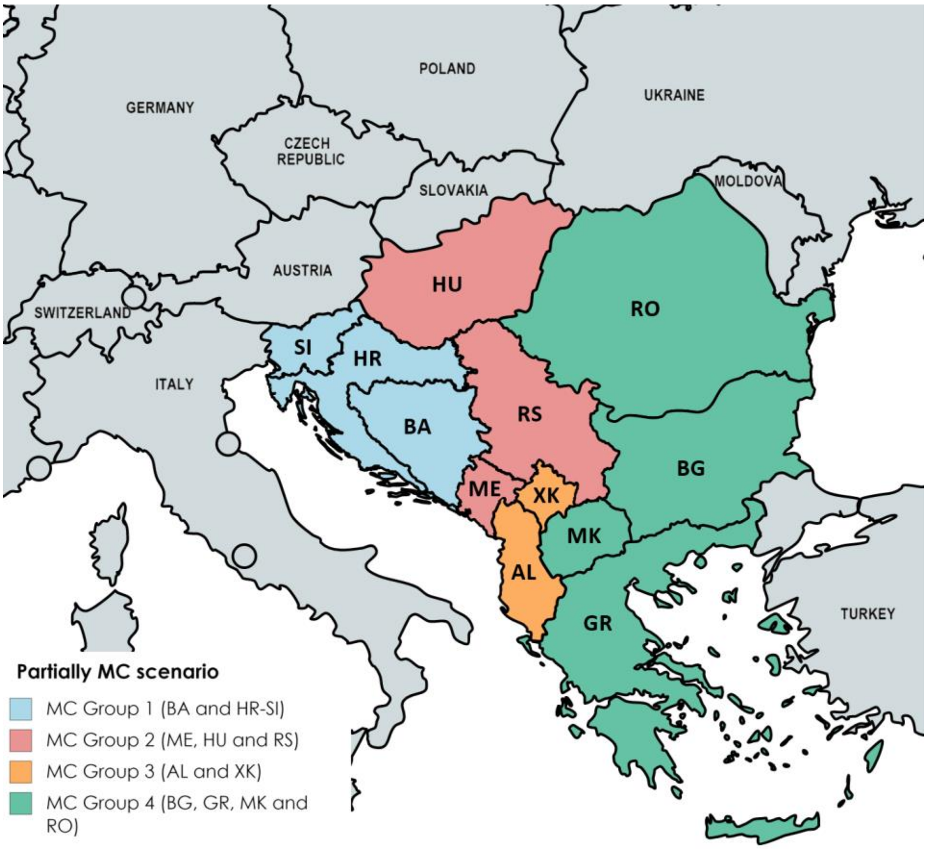


Figure 2: EMI Partial market coupling scenario (PMC) groups and market areas

Summary of our Findings. We illustrate the main impacts of partial and full market coupling in 2025 through presenting its impacts on the levels of power exports and imports; changes in wholesale market prices; and socio-economic welfare for the EMI market areas and the region:

Exports and Imports. Through coupling of the market areas inside the SEE region, both total exports from and imports to the SEE region will increase, and the increase in exports will be higher. We conclude that in all scenarios, stronger market coupling enables higher net exchange (higher exports) between the SEE region and the rest of the world. This is because of the ability to utilize generation more efficiently across the region as coupling and market integration increase, and also because coupling leads to greater utilization of the available net transmission capacity (NTC).

This increase in net exchange and exports is substantial - between 19% and 61% depending on the scenario. Different development alternatives and operating conditions in the four sets of market conditions would produce a significantly different level of exports:

- In separated markets: exports range from 3,6 TWh (in the Dry hydrology condition) to 18,7 TWh (the condition with high RES penetration and low demand);
- In fully coupled markets: exports range from 5,8 TWh (in the Dry hydrology condition) to 22,2 TWh (the condition with high RES penetration and low demand).

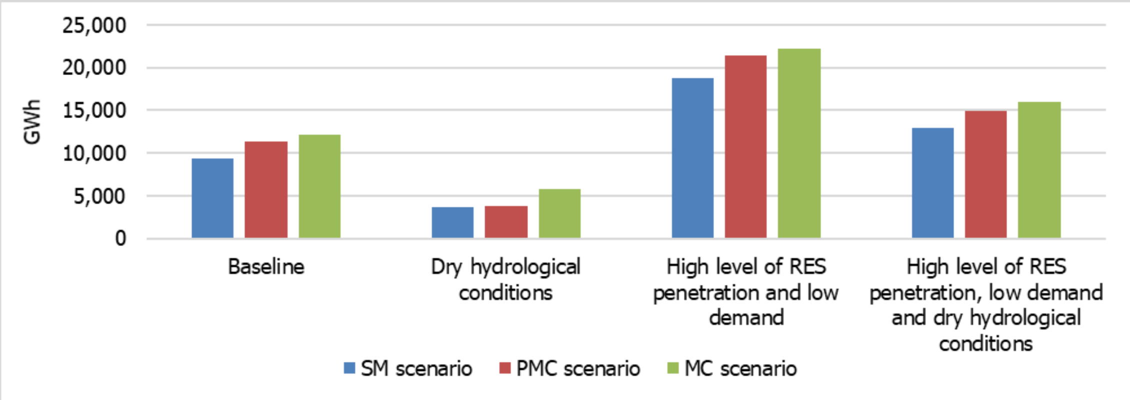


Figure 3: Net interchange (net export) in 2025, of the SEE region with the rest of Europe (all scenarios and MC levels)

Our general conclusion is that the increased utilization of cross-border capacities that comes with increased coupling and market integration will enable both higher exports from the SEE region (Figure 3), and higher exports and imports within the EMI market areas (Figure 4, Figure 5, Figure 6, Figure 7).

The level of net interchange varies substantially by country. The most consistent exporters across all scenarios and market conditions tend to be BG, RO, BA and RS, XK and SI to a lesser extent, while the most consistent importers tend to be GR, HR, ME and MK. AL switches between net exporting and importing based on hydro conditions. While not on these charts, exports from SEE flow mostly to Hungary, Turkey and Italy, and to Central Europe to a lesser extent. In sum, **market integration is a clear positive for importing countries which enjoy lower wholesale power prices as a result, and for exporting countries due to the increased export revenues that they produce.**

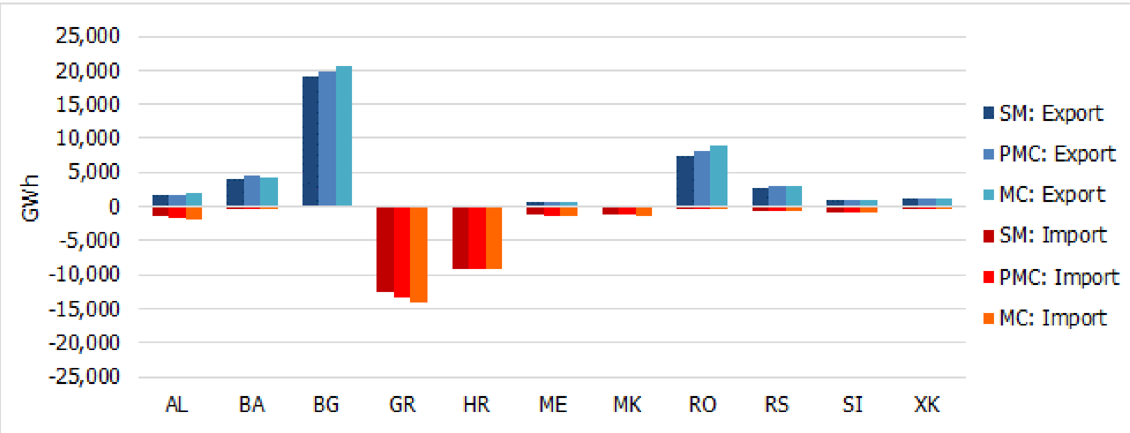


Figure 4: Comparison of exports and imports in 2025 (Baseline)

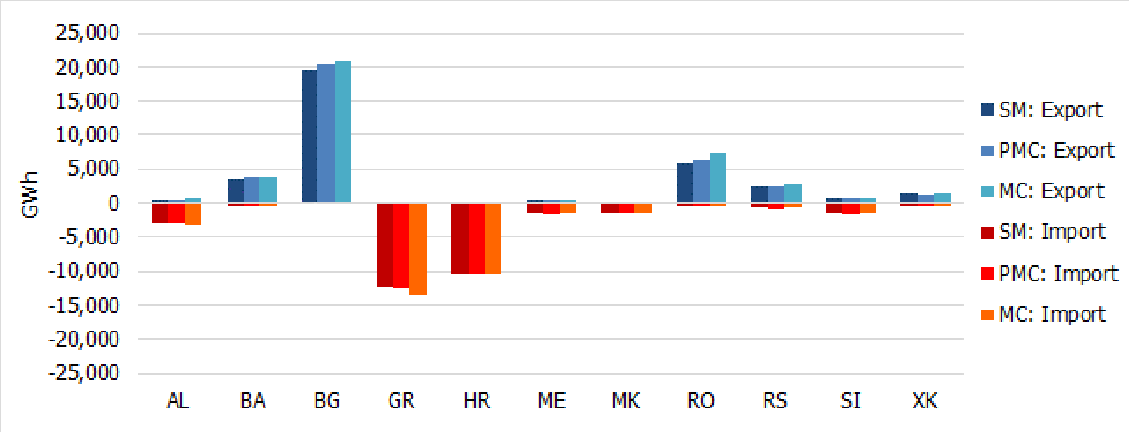


Figure 5: Comparison of exports and imports in 2025 (Dry hydrological conditions)

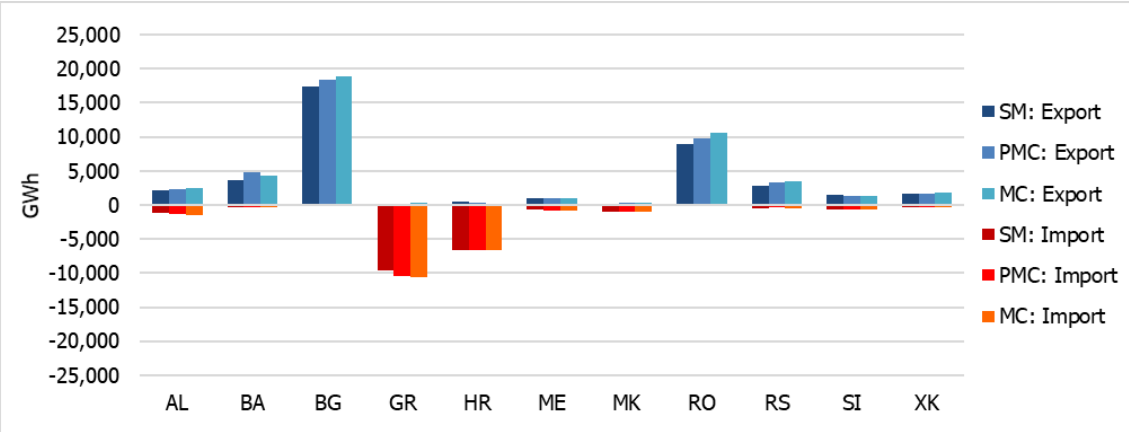


Figure 6: Comparison of exports and imports in 2025 (High RES and low demand)

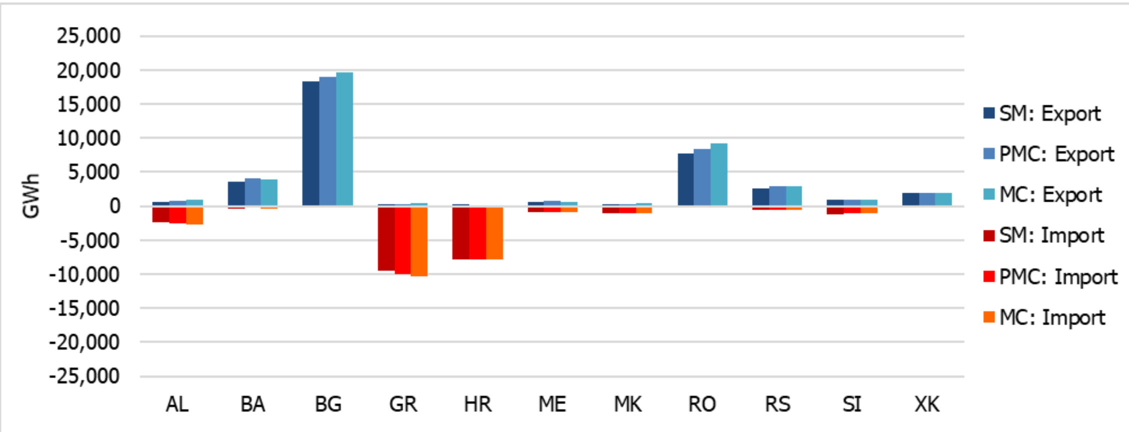


Figure 7: Comparison of exports and imports in 2025 (High RES, low demand and dry hydrological conditions)

It is worthwhile to look more closely at these figures on an individual country basis, which we expect the EMI members will do, and assess the policies that could optimize their situation. While regulators and policy makers can do little to affect the level of hydro, they can influence the level of demand and the level of RES. Transmission companies and market operators have a role to play in these conversations, as the grid and cross-border transactions will need to respond to such changes.

Wholesale Prices. Looking at the impact on wholesale electricity prices (Figure 8 - Figure 12), this analysis shows that:

- Across all scenarios and conditions, we expect average weighted prices for the whole SEE region in 2025 to range from 50.04 to 58.70 €/MWh, while in particular market areas and conditions, those prices show a wider range, from 48.01 €/MWh to 69.57 €/MWh.
- Prices would be the highest in dry hydrological conditions, rising 3.0% to 4.6% across the boards compared to the baseline scenario (a notable but modest impact on the whole):
  - Min: 53.92 €/MWh (ESO EAD market area)
  - Max: 69.57 €/MWh (ADMIE/IPTO market area)
  - Average for SEE region: 58.70 €/MWh to 57.40 €/MWh for different MC variants

  This result is expected, given that HPPs provide about 25% of overall generation in the region, and dry hydrological conditions would require the use of higher cost resources, while also presenting the most stressed operating conditions in the region.
- By contrast, average wholesale prices in 2025 would be the lowest if demand growth is slower, and RES development is faster. For the SEE region as a whole, wholesale power prices are 9.2% to 10.8% lower than under the baseline conditions (a major reduction):
  - Min: 48.01 €/MWh (TransElectrica market area)
  - Max: 54.97 €/MWh (HOPS market area)
  - Average for SEE region: 50.04 €/MWh to 50.59 €/MWh for different MC variants

  This is also expected, for several reasons: 1) as in all other cases, these are wholesale prices determined as marginal operating costs (without the investment component); 2) lower demand allows the use of cheaper generating units; and 3) with higher RES participation, a larger share of demand is supplied by RES at essentially zero operating costs.
- In the expected demand case, (both Baseline and Dry hydrology scenarios), prices decrease with stronger market coupling. The reason for this somewhat unexpected result lies in the fact that we have calculated average prices at the regional level as load-weighted average values. Since there is a significant price decrease (between 4 and 7.5 €/MWh) in a large market area (ADMIE/IPTO) and, at the same time, a small price increase (just from 1 to 3 €/MWh) in another large market area (TransElectrica), the average calculated values show a decrease as market coupling gets stronger.
- In the case of high RES and slower demand development, wholesale market prices are generally lower in the SEE region compared to neighboring market areas. Thus, stronger market coupling could lead to an increase of exports to these markets and a slight increase in wholesale prices. This is expected, keeping in mind that changes in prices (increase or decrease) are similar among market areas and below 2 €/MWh.
- As mentioned above, in the most stressed operating condition (dry hydrology), prices are the highest, and the prices variation coefficient (CV) is the highest as well. Even in full market coupling, wholesale prices stay the most divergent in this scenario (Table 1), i.e. there is a higher degree of variation among prices in individual market areas.

- Prices variation coefficient is expressed as a percentage, and is calculated as the ratio of the standard deviation to the mean (average) of prices in EMI market areas. It measures the price variation within a scenario between the 11 market areas. **As expected, stronger market coupling provides for price convergence**; the variation between markets falls 45-55% from the SM to the FMC scenario (e.g., from 5.59% to 2.56% in the Baseline).

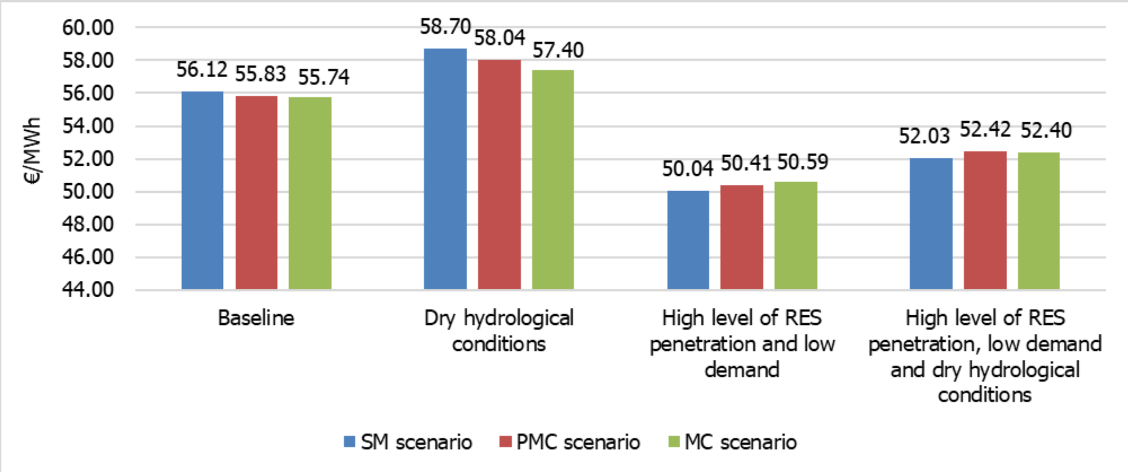


Figure 8: Wholesale electricity prices in 2025 (all scenarios and MC levels)

Table 1: Prices Variation Coefficients in 2025 (all scenarios and MC levels)

Prices variation (%)	Baseline	Dry hydrological conditions	High level of RES penetration and low demand	High level of RES penetration, low demand and dry hydrological conditions
Separated markets	**5.59%**	**7.07%**	**4.76%**	**3.75%**
Partial market coupling	**3.17%**	**4.17%**	**3.11%**	**2.55%**
Full market coupling	**2.56%**	**3.32%**	**2.54%**	**2.05%**

Figures 9 through 12 demonstrate the modeled impact on wholesale prices for each EMI member in conjunction with increased market integration. By 2025, the countries that we would expect to experience consistent wholesale price decreases would be GR, SI and HR; on the other hand, forecasted wholesale prices in BG, RO, and MK would tend to increase a bit; while in BA, XK, ME, RS and AL, wholesale prices are more complicated, and either rise or fall a bit based on the scenario.

In reality, we expect there to be downward pressure on wholesale market prices for a host of reasons described below in the "Caveats" section of this Executive Summary, such that wholesale prices could well decrease for all SEE market areas, particularly over a longer period of time.

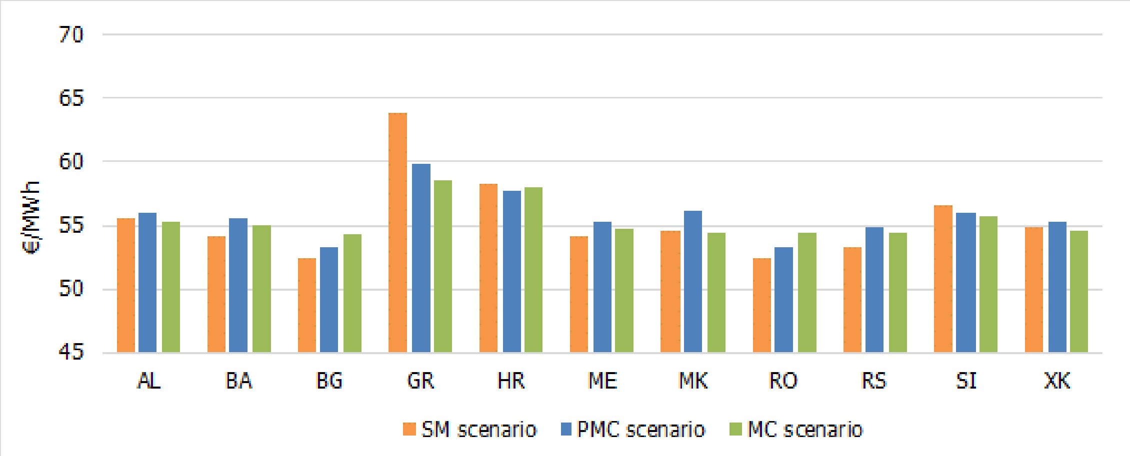


Figure 9: Comparison of average wholesale prices in 2025 (Baseline)

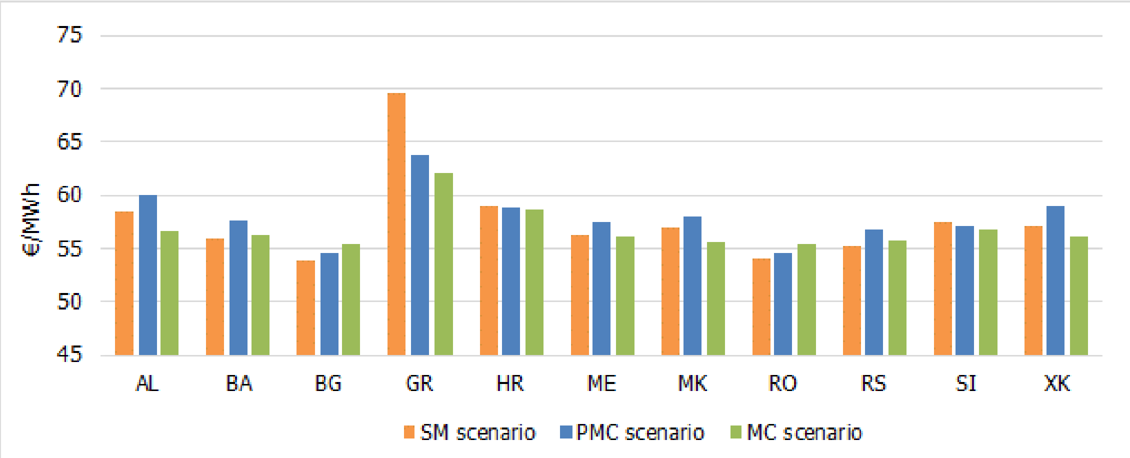


Figure 10: Comparison of average wholesale prices in 2025 (Dry hydrological conditions)

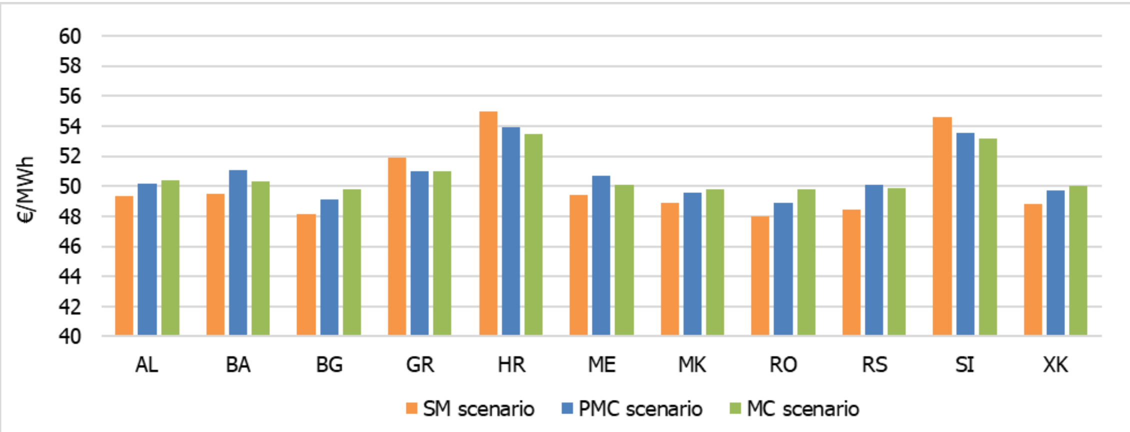


Figure 11: Comparison of average wholesale prices in 2025 (High RES and low demand)

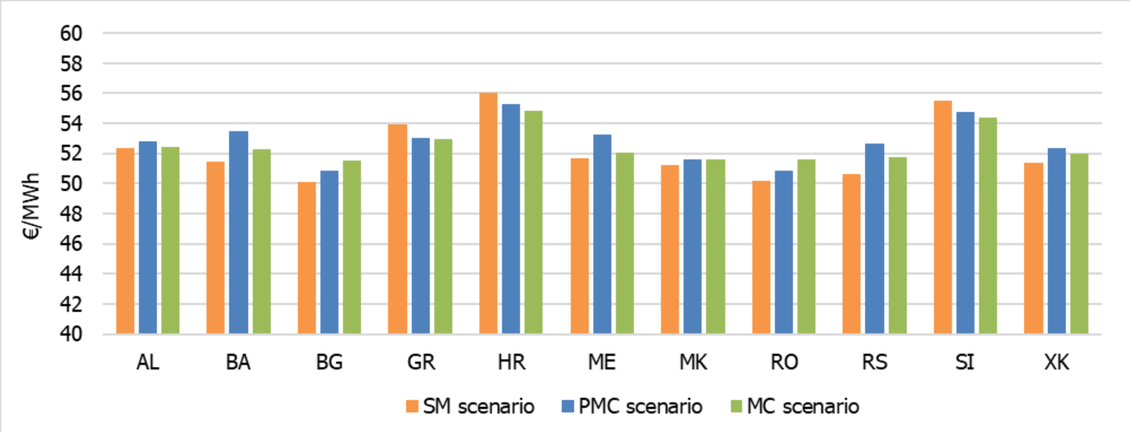


Figure 12: Comparison of average wholesale prices in 2025 (High RES, low demand and dry hydrological conditions)

It is noteworthy that higher exports from the SEE region (to Turkey, Italy and Central Europe) will increase wholesale prices at the regional level, since internal market coupling will unlock more expensive generation that is not utilized in the SM and PMC cases. As mentioned above, each country can evaluate the conditions and scenarios that would lead to these changes, and the policy implications, as greater market integration tends to equalize prices across borders.

Socio-Economic Welfare (SEW). After analyzing different market parameters, we calculate the change in social-economic welfare (SEW) in order to fully evaluate overall impacts of regional market integration in SEE region. According to the ENTSO-E definition, SEW is measured through the change in total surplus (the sum of consumer surplus, producer surplus and congestion rents) in the PMC and MC scenarios, compared to the SM scenario. **For the whole SEE region, every scenario and market coupling variant would produce at least 20 million € in benefits compared to separated markets, and those benefits increase substantially – about 50% - from partial to full market coupling.** ***This is a notable point in favor of consolidating power markets.***

The biggest benefit of market coupling compared to separated markets would occur in the most stressed operating conditions (dry hydrology), when SEW can reach 41 million €. We expect similar benefits in the Baseline scenario, and the scenario with lower demand and increased RES - 37 million €. The lowest SEW benefits (30 million €) under FMC can be expected with dry hydro, slow demand growth, and increased RES, which is still substantial.

Table 2: SEW variation compared to separated markets, across scenarios and MC levels in 2025

Δ SEW (million €)	Baseline	Dry hydrological conditions	High level of RES penetration and low demand	High level of RES penetration, low demand and dry hydrological conditions
Partial market coupling	26.23	27.28	23.64	20.62
Full market coupling	37.02	40.86	37.28	30.02

In general, the largest benefits across scenarios and levels of integration in SEE would occur in the ADMIE/IPTO and ELES market areas. For the ADMIE/IPTO market area, the main reason is the presence of adequacy issues (or energy not served (ENS)), which leads to a meaningful price decrease and thus an increase in SEW with stronger market coupling. For ELES, the key reasons are increased, significant transit of power flows across the country, and price differences with neighboring market areas.

In fact, for most countries, under most conditions, the SEW is positive, some quite substantially so. These benefits can also be related to the size of the power markets and economies (e.g., a million euros is a larger share of the economy in some countries versus others). Also, we have modeled the impact of these scenarios and conditions without policy changes. These benefits would grow if countries enact programs to increase their SEW and that of the SEE region.

While the region as a whole clearly benefits, the SEW in individual market areas could fall a bit with stronger market coupling (see Table 3 - Table 6). The decreases occur mainly due to either: a) large decreases in congestion rents on some borders (e.g., BG-GR); or b) to price increases in smaller importing market areas (e.g., MEPSO or CGES) due to a stronger connection with exporting and importing areas, and an increase in power transits. Also, in a small but exporting market area, such as KOSTT, the decrease in transits, congestion and wholesale prices in some scenarios leads to a decrease in SEW. The same is true for the HOPS market area, which is an importing area between areas with significant price differences (NOSBiH and HU).

In every case, congestion rent falls substantially with greater market integration, as expected, since a much higher share of the NTCs are utilized when markets are coupled. The levels of producer surplus and consumer surplus, however, varies widely, and is either notably negative or positive, depending on the scenario and level of market integration.

Table 3: Comparison of socio-economic welfare changes in 2025 (Baseline)

Market area	Partial market coupling - Separated markets				Full market coupling - Separated markets			
million €	Δ Producer surplus	Δ Consumer surplus	Δ Congestion rent	Δ Total surplus	Δ Producer surplus	Δ Consumer surplus	Δ Congestion rent	Δ Total surplus
AL	8.02	-4.52	-1.41	**2.08**	6.01	2.04	-4.37	**3.68**
BA	30.06	-19.58	-3.24	**7.24**	17.08	-11.82	-0.08	**5.18**
BG	48.50	-32.13	-22.40	**-6.03**	102.05	-67.24	-44.08	**-9.28**
GR	-182.28	244.03	-44.69	**17.05**	-238.53	324.82	-56.46	**29.83**
HR	-10.56	10.41	-5.27	**-5.42**	-10.44	4.36	4.59	**-1.49**
ME	7.88	-5.18	-3.06	**-0.37**	3.50	-2.69	-3.52	**-2.71**
MK	12.01	-13.09	-0.19	**-1.27**	0.55	2.14	-7.87	**-5.18**
RO	56.84	-50.40	-4.42	**2.03**	137.20	-120.37	-12.36	**4.48**
RS	60.13	-56.21	-1.38	**2.54**	46.89	-41.57	-5.10	**0.22**
SI	-8.48	8.71	5.63	**5.86**	-12.48	12.83	14.09	**14.44**
XK	4.86	-2.84	0.50	**2.53**	-0.10	1.71	-3.76	**-2.14**
TOTAL SEE	**26.97**	**79.19**	**-79.94**	**26.23**	**51.72**	**104.22**	**-118.92**	**37.02**

Table 4: Comparison of socio-economic welfare changes in 2025 (Dry hydrology Scenario)

Market area	Partial market coupling - Separated markets				Full market coupling - Separated markets			
million €	Δ Producer surplus	Δ Consumer surplus	Δ Congestion rent	Δ Total surplus	Δ Producer surplus	Δ Consumer surplus	Δ Congestion rent	Δ Total surplus
AL	11.41	-12.68	-2.35	**-3.62**	-4.15	15.89	-5.55	**6.19**
BA	30.98	-21.12	-4.78	**5.07**	6.63	-3.53	-0.06	**3.04**
BG	39.06	-25.52	-29.41	**-15.87**	79.82	-50.50	-53.40	**-24.07**
GR	-269.39	363.48	-61.55	**32.54**	-345.29	469.18	-72.01	**51.87**
HR	-6.21	5.44	-6.19	**-6.96**	-10.51	9.01	3.06	**1.56**
ME	7.50	-5.38	-0.37	**1.75**	-0.30	1.34	-3.59	**-2.56**
MK	8.12	-9.53	-0.55	**-1.96**	-7.20	11.87	-7.06	**-2.40**
RO	44.40	-39.83	-2.42	**2.15**	100.68	-88.64	-11.04	**1.00**
RS	62.61	-58.21	0.43	**4.83**	22.70	-15.53	-4.86	**2.30**
SI	-4.35	4.81	4.07	**4.53**	-8.59	9.15	8.88	**9.44**
XK	16.41	-12.70	1.10	**4.81**	-7.05	6.57	-5.02	**-5.51**
TOTAL SEE	**-59.46**	**188.76**	**-102.02**	**27.28**	**-173.26**	**364.80**	**-150.67**	**40.86**

Table 5: Comparison of socio-economic welfare changes in 2025 (High RES and low demand)

Market area	Partial market coupling - Separated markets				Full market coupling - Separated markets			
million €	Δ Producer surplus	Δ Consumer surplus	Δ Congestion rent	Δ Total surplus	Δ Producer surplus	Δ Consumer surplus	Δ Congestion rent	Δ Total surplus
AL	8.88	-6.05	-0.75	**2.08**	14.37	-8.20	-2.45	**3.72**
BA	28.22	-20.83	-0.46	**6.93**	17.23	-11.07	0.21	**6.37**
BG	48.31	-33.12	-12.06	**3.13**	86.79	-56.31	-21.26	**9.21**
GR	-38.67	54.64	-15.26	**0.71**	-31.49	52.41	-19.84	**1.07**
HR	-20.88	20.69	-2.01	**-2.20**	-29.09	28.66	3.47	**3.05**
ME	6.56	-4.91	-1.86	**-0.21**	4.02	-2.68	-2.87	**-1.53**
MK	6.07	-5.81	-1.32	**-1.06**	8.12	-7.13	-3.85	**-2.86**
RO	57.91	-51.11	-6.64	**0.15**	121.09	-103.11	-16.27	**1.71**
RS	61.67	-59.18	0.37	**2.85**	55.60	-51.25	-2.53	**1.82**
SI	-15.44	14.91	9.56	**9.02**	-21.34	20.70	14.60	**13.96**
XK	7.16	-5.20	0.26	**2.23**	9.11	-6.68	-1.65	**0.77**
TOTAL SEE	**149.78**	**-95.96**	**-30.18**	**23.64**	**234.41**	**-144.67**	**-52.46**	**37.28**

Table 6: Comparison of socio-economic welfare changes in 2025 (High RES, low demand and dry hydrological conditions)

Market area	Partial market coupling - Separated markets				Full market coupling - Separated markets			
million €	Δ Producer surplus	Δ Consumer surplus	Δ Congestion rent	Δ Total surplus	Δ Producer surplus	Δ Consumer surplus	Δ Congestion rent	Δ Total surplus
AL	4.94	-3.71	-0.28	**0.95**	4.90	-0.97	-2.22	**1.71**
BA	36.63	-26.62	-3.72	**6.29**	15.05	-10.43	-0.49	**4.13**
BG	37.95	-25.22	-9.6	**3.13**	76.7	-49.15	-19.98	**7.57**
GR	-38.48	52.86	-14.05	**0.33**	-35.72	56.75	-19.47	**1.56**
HR	-15.48	15.47	-5.06	**-5.07**	-22.9	23.08	2.81	**2.99**
ME	7.96	-6.28	-2.22	**-0.54**	2.22	-1.47	-2.12	**-1.37**
MK	3.1	-2.57	-0.63	**-0.1**	4.14	-2.94	-3.77	**-2.57**
RO	45.2	-39.79	-3.7	**1.71**	100.84	-86.09	-13.63	**1.12**
RS	75.6	-72.46	0.53	**3.67**	45.13	-40.48	-2.37	**2.28**
SI	-10.57	10.96	7.34	**7.73**	-16.18	16.66	12.2	**12.68**
XK	7.26	-5.14	0.4	**2.52**	4.98	-3.27	-1.83	**-0.12**
TOTAL SEE	**154.1**	**-102.5**	**-30.99**	**20.61**	**179.17**	**-98.29**	**-50.86**	**30.02**

Caveats on this Analysis: Why Benefits Will be Greater

While the market model we deployed for this work is highly sophisticated, it cannot capture all market dynamics. Also, while this analysis focused on 2025, the factors that produce benefits will continue to grow over time. Thus, we believe that the benefits from market integration quantified herein are conservative, and should be higher due to a number of factors:

1. Greater Energy Security, Reduced Reserves and Lower Volatility. As markets consolidate in SEE, more generation diversity, size ranges and scale will reduce price volatility from short term spikes in fuel prices, droughts or other disruptions. It will also make power supplies more secure at lower levels of reserves. In such situations, power markets and power pools worldwide have been able to significantly reduce capacity reserves (e.g., the PJM and ERCOT capacity reserves have gone from about 20% to 10-12%) without reducing reliability. The size of the SEE market plus Italy is approximately the size of the PJM, so we can expect the impact of such market diversity and size to meaningfully reduce the need for new spinning reserves and generation, saving customers substantially in the process. This is before such benefits that may arise as distributed generation grows.

2. Increased Resilience. When market areas and generation resources are larger, the system is more resilient to disasters or shocks, less subject to outages, and will recover more quickly, as the failure of one component will not have the impact on an entire region to the extent that it would have on individual countries. Fuel diversity also increases, so the availability of a single fuel (e.g., hydro) is less critical. This diversity benefit occurs to a lesser extent when countries couple their markets as well. There are risks that arise on a regional level through integration (e.g., cyber), but the resilience tradeoffs are more than worth it.

3. Competitive Market Forces. It is well documented worldwide that when markets develop, and generation opens to competition, the new entrants will lower operating costs, operate more efficiently, deploy and propose more new technologies, and pressure incumbents to do so as well. Our work did not assume any changes in technology between now and 2025. These competitive forces are not just true for RES, with its low if not zero operating costs. Combined

cycle (CC) gas generation was first adopted by US independent power firms in the 1980s, shortly after a new law (called PURPA) allowed private companies to generate and sell power to utilities; CC gas generation now has plant efficiencies double that of older coal facilities. We should see a similar phenomenon in Southeast Europe (SEE), both with RES and CC plants, especially as gas resources from Azerbaijan start to generate power in SEE after 2025. True competition will place substantial downward pressure on wholesale power costs in SEE, and produce more benefits for customers.

4. Increasing Market Transparency. While there are a number of power exchanges, there is no regional wholesale market for power in SEE now, and the existing exchanges, particularly in the WB6 region, have few market participants. Over time, post 2025, with the transparency created by market coupling (with higher NTCs), we would expect vibrant power exchanges, new fuel supplies and competitive solicitations for new power plants to root out extra costs, and bring wholesale prices down to levels comparable to other regions in Europe.
5. Market Integration with Central Europe. Just as this study shows a substantial convergence of prices taking place within SEE market areas under increasing levels of market integration by 2025, the post-2025 integration of the electricity market in SEE with Central Europe will promote a convergence with the lower prices in that region, and thus will reduce wholesale power costs in SEE. Annual as well as daily wholesale power prices in SEE now average 50-plus Euros per MWh, substantially above wholesale power prices in Central and Western Europe (often higher by 20%, 30% or more, i.e., 15 to 20 Euros).
6. Congestion Rents, NTCs, and Higher SEWs. The standard calculation of SEW includes congestion rent. However, congestion does not benefit customers, and there is an argument that SEW assessment should be independent of congestion rents. In this report, congestion rent reduces SEW by 30-150 million Euros, depending on the scenario, which in most cases is higher on its own than the highest regional SEW in our analysis (about 40 million Euros). Coupled, transparent, competitive markets should greatly minimize if not eliminate congestion over time (in fact, our next EMI study will explore such opportunities). As we identify regional bottlenecks, there will be incentives to expand and upgrade the cross-border connections that are impeding economic flows, leading to higher NTCs. Taking congestion rent out of the equation would lead to substantial SEW increases for all, and lead to no negative SEWs for individual countries under the conditions modeled in 2025.
7. Country Policy Changes. This work did not model any changes in country policies such as ones designed to lower electricity demand, raise RES levels, or facilitate market integration before 2025, though there are a number of ongoing coupling negotiations. Actions by regulators and policy-makers in specific couplings could bring about benefits sooner.

For the reasons above, actual benefits in 2025 and beyond are likely to be noticeably better than in this Report. In particular, the results of this EMI analysis show that greater market integration is a firm foundation for a host of other benefits that will continue to put downward pressure on wholesale power prices and increase SEW for many years to come.

As a result, we believe that with greater market integration, wholesale power costs in all SEE markets could well decrease, SEWs will be higher, and that those benefits will grow larger over time.

We strongly encourage TSOs, MOs and other EMI stakeholders in SEE to use the results and conclusions in this market analysis to carry out their own assessments, and as appropriate, to proceed with a higher level of electricity market integration for their countries and the SEE region.

1 INTRODUCTION

Electricity markets in Southeast Europe (SEE) are characterized by relatively few market players in each country, and low liquidity in day-ahead (DA) and intra-day (ID) markets. The incumbent power utilities are the dominant generators in practically all countries in the region, limiting the possibilities for true competition within national borders and between generators in different countries.

One of the goals of the Electricity Market Initiative (EMI) is to work with the transmission system operators (TSOs) and market operators (MOs) to evaluate the possible benefits of accelerating the integration of and competition among electricity markets in the Western Balkans (WB6) and neighboring countries of Southeast Europe (SEE). Analyzing and forecasting these potential benefits will support more rapid implementation of the regional objectives that aim to implement the coupling of day-ahead electricity markets in the entire WB6 and with all neighboring EU Member States (EU MS). Figure 13 below shows the region on which the EMI focuses, and the 15 current members in this program.

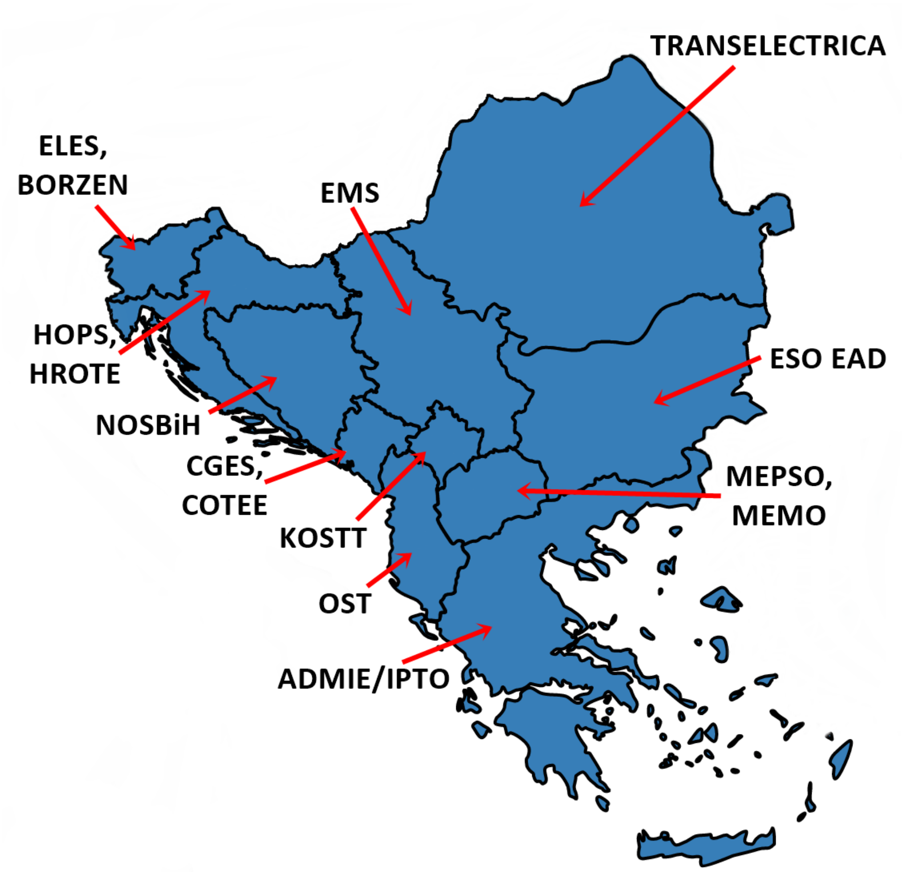


Figure 13: EMI Members

The objective of this task was to analyze and quantify the impacts of electricity market integration in the SEE region. In general, market integration can refer to electricity markets in different timeframes and products (futures, day-ahead, intraday, real time - balancing, reserves) but within this assignment, the focus is on the wholesale day-ahead electricity market.

It can be expected that the integration of relatively small electricity markets in the region, in conjunction with other changes, will produce a number of benefits, such as: raise the efficiency of regional generation and cross-border transmission resources compared to individual country dispatch; increase the size and liquidity of such markets; attract non-incumbents as well as existing utilities to make such markets more competitive; put downward pressure on wholesale prices; modify the generation mix (towards less polluting generation and more renewables or RES); and raise overall social-economic welfare (SEW).

To capture and project the impact of such integration, this work has utilized a complex regional electricity market model (called Antares) that includes all existing and planned generating capacities in SEE with a simplified representation of the transmission network. This analysis focused on the year 2025, and the team carried out hourly simulations of the power system operation in order to produce results for each hour.

Even with this level of sophistication, there are limits to the ability of this model to capture all the market changes that would actually occur with greater market integration, and thus, the benefits that would occur are under-stated in our results. As in standard, usual market simulations, the following assumptions are applied:

- No market power is applied (bids are equal to short-run marginal costs);
- Price inelastic demand is applied;
- Simulations are based on zonal day-ahead market principles;
- Network constraints are modeled as NTC values.

We have compiled and tested the Antares model, and will transfer it to the EMI participants for their internal purposes, with appropriate training. To summarize, the overall goals were twofold:

1) to determine the impacts on wholesale power costs and other market indicators as one expands the geography of the analysis from individual countries/market areas, to groupings or couplings of countries, and then to the entire SEE region; and
2) to develop a useful tool for the EMI participants to perform market analyses according to their internal needs.

We expect both of these goals to promote the more rapid integration of power markets in SEE, particularly in the WB6, and their integration into other European power markets.

This Final Report provides the market simulation results for 12 scenarios (three different market coupling scenarios in four different circumstances - the base case, plus changes in hydrological conditions, RES penetration and demand growth), and calculates the overall impacts of regional market integration in the SEE region.

2 MODELING ASSUMPTIONS

Before the team could carry out the detailed analysis of the impacts of market integration, we needed to gather considerable data from the EMI members, and use it to populate the model. Creation of the EMI market modeling database for the SEE region comprised the following 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 2025 from the TSOs and MOs through a comprehensive spreadsheet and a request for data
- Clarification of any missing input data and suggestions for solutions, including sources such as PEMDB, TYNDP, MAF and other publicly available sources, as well as the Consultants' databases

We used the following approach to model the generation fleet:

- We represented all 11 market areas – for OST, NOSBiH, ESO EAD, HOPS, ADMIE/IPTO, KOSTT, MEPSO, CGES, TransElectrica, EMS and ELES - on a plant-by-plant level of detail, with hourly demands and non-dispatchable generation
- We modeled the Hungarian market area by technology clusters (hydro by type, thermal by fuel type, nuclear, RES), also with hourly demand and non-dispatchable generation
- We modeled Turkey, Central Europe and Italy as spot markets, in which the market price is insensitive to SEE price fluctuations, and constrained by cross-border transmission capacity.

These are the technical and economic parameters we included in the market model for 2025:

1. Thermal power plants (TPPs)

- General data (plant name, ownership, number of units, fuel type)
- Operational status – current state and target year per unit
- Maximum net output power per unit
- Minimum net output power per unit
- Heat rates at maximum net output power per unit
- Heat rates at minimum net output power per unit
- Fuel cost per unit
- Fixed O&M costs per unit
- Variable O&M costs per unit
- Outage rates (FOR, MOR) and maintenance periods per unit
- CO_2 emission factor per unit
- Operational constraints (ramping limits, 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). More info can be found in Appendix II.

2. Hydro power plants (HPPs)

- General data (plant name, ownership, number of units)
- Operational status – current state and target year
- Plant type (run of river, storage (seasonal, weekly, daily, pumped storage plant)
- Maximum net output power per unit
- Minimum net output power per unit
- Biological minimum production
- Reservoir size
- 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 inflows or generation for storage plants, monthly generation for run of river plants for 3 hydrological conditions: average, dry and wet

3. Renewable energy sources (RES)

- 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

- Annual consumption expected in 2025 (GWh)
- Hourly load profiles for 3 characteristic climatic years: 1982, 1984 and 2007

5. Network capacity

- NTC values applied as cross-border limits for the winter/autumn and summer/spring seasons

All the EMI's TSOs and MOs gathered and placed the above data in a large spreadsheet that the consultants had prepared. For unavailable data, we used other verified, publicly available official data, along with the consultants' documents and estimates, taking care to maintain the consistency of the input dataset. The data mainly originated from the ENTSO-E Market Modeling Database, TYNDP 2018 and MAF 2018 datasets, with data from the SECI project if other data was not available.

The five sub-sections below describe our approach in gathering the data and modeling relevant items in support of the EMI analysis, including: load, wind and solar profiles; hydro plant generation; thermal power plants; fuel and CO_2 prices; and neighboring power systems.

2.1 Load, wind and solar hourly profiles

In general, if the TSOs and MOs could not provide hourly load profiles for 1982, 1984 and 2007 climatic years, we utilized publicly available data from the TYNDP 2018, 2025 Best Estimate Scenario. This level of consumption is the expected Baseline Scenario consumption (Base Case) that we

[2] Characteristic climatic years used in preparation of the TYNDP 2018 report. These climatic years have been determined as being optimum and adequate to demonstrate the impact of 34 climatic years on the results.

analyzed in this study. In the alternative scenarios with low demand, we calculated total consumption using a reduced annual growth rate, and applied the same hourly profiles.

In addition, if the EMI members did not provide wind and/or solar hourly capacity factors, we used publicly available databases from ETH Zurich[3]. If data was unavailable for the selected climatic years of 1982, 1984 and 2007, we used data from 2013, 2009 and 2015 instead, reflecting the idea that each selected climatic year represents several years with similar characteristics[4]. If data was completely unavailable from a country, we used data from neighboring countries.

We used the installed capacities provided in the EMI members' spreadsheets in the Baseline Scenario. In the alternative scenarios with higher RES capacity (High RES Scenario), we determined the installed capacities by using the wind and solar capacities expected in 2030 in the Sustainable Transition Scenario analyzed in TYNDP 2018, which would accelerate the development of RES by five years.

2.2 Generation from hydro power plants (HPPs)

For HPPs, the EMI members could not always provide data on monthly generation in different hydrological conditions, in which case we used data from the SECI project or estimated HPP generation based on the Consultant's experience and other hydro generation data. If only data for average hydrology are available, we generally assumed that dry and wet generations were 25% lower and higher. This assumption is based on wet and dry hydro generations submitted for some of the countries, enabling a harmonized regional approach.

2.3 Technical and economic parameters – thermal power plants

Unless specified differently in the spreadsheet, we applied general technical and economic parameters for all TPPs, as shown in the following tables (Table 7, Table 8 and Table 9).

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

[4] https://tyndp.entsoe.eu/Documents/TYNDP%20documents/TYNDP2018/consultation/Main%20Report/TYNDP18%20Exec%20Report%20appendix.pdf

Table 7: General technical and economic parameters for TPPs from the common database

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	Start-up fuel consumption - warm start	Start-up fix cost (e.g. wear) warm start	Heat Rate (GJ/MWh)
			%	%	kg / Net GJ	€/MWh	hours	hours	Net GJ /MW. start	€ /MW. start	%
1	Nuclear	-	30% - 35%	33%	0	9	12	12	14.0	21	10.91
2	Hard coal	old 1	30% - 37%	35%	94	3.3	8	8	18.0	70	10.29
3		old 2	38% - 43%	40%		3.3	6	6	18.0	50	9.00
4		New	44% - 46%	46%		3.3	5	5	18.0	42	7.83
5		CCS	30% - 40%	38%	9.4	6.6	7	7	18.0	50	9.47
6	Lignite	old 1	30% - 37%	35%	101	3.3	11	11	18.0	70	10.29
7		old 2	38% - 43%	40%		3.3	9	9	18.0	50	9.00
8		New	44% - 46%	46%		3.3	8	8	18.0	42	7.83
9		CCS	30% - 40%	38%	10.1	6.6	10	10	18.0	50	9.47
10	Gas	conventional old 1	25% - 38%	36%	57	1.1	5	5	7.6	68	10.00
11		conventional old 2	39% - 42%	41%		1.1	5	5	7.6	45	8.78
12		CCGT old 1	33% - 44%	40%		1.6	3	3	7.6	73	9.00
13		CCGT old 2	45% - 52%	48%		1.6	3	3	7.6	43	7.50
14		CCGT new	53% - 60%	58%		1.6	2	2	7.6	25	6.21
15		CCGT CCS	43% - 52%	51%	5.70	3.2	4	4	7.6	43	7.06
16		OCGT old	35% - 38%	35%	57	1.6	1	1	0.2	52	10.29
17		OCGT new	39% - 44%	42%		1.6	1	1	0.2	20	8.57
18	Light oil	-	32% - 38%	35%	78	1.1	1	1	0.2	36	10.29
19	Heavy oil	old 1	25% - 37%	35%	78	3.3	3	3	7.6	70	10.29
20		old 2	38% - 43%	40%		3.3	3	3	7.6	50	9.00
21	Oil shale	old	28% - 33%	29%	100	3.3	11	11	18.0	60	12.41
22		new	34% - 39%	39%		3.3	8	8	18.0	42	9.23

Table 8: Additional technical parameters for TPPs from the common database

Category #	Fuel	Type	Unavailability				Minimum stable generation	Ramp up rate	Ramp down rate	Fixed generation reduction
			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)	MW/h	MW/h	% of max output power
1	Nuclear	-	5%	7	54	15%	50%	For all unit types, hourly ramp rate is equal to the average unit size.	For all unit types, hourly ramp rate is equal to the average unit size.	0%
2	Hard coal	old 1	10%	1	27	15%	43%			0%
3		old 2	10%	1	27	15%	43%			0%
4		new	7.50%	1	27	15%	43%			0%
5		Lignite CCS	7.50%	1	27	15%	43%			0%
6	Lignite	old 1	10%	1	27	15%	43%			0%
7		old 2	10%	1	27	15%	43%			0%
8		new	7.50%	1	27	15%	43%			0%
9		Hard coal CCS	7.50%	1	27	15%	43%			0%
10	Gas	conventional old 1	8%	1	27	15%	35%			0%
11		conventional old 2	8%	1	27	15%	35%			0%
12		CCGT old 1	8%	1	27	15%	35%			0%
13		CCGT old 2	8%	1	27	15%	35%			0%
14		CCGT new	5%	1	27	15%	35%			0%
15		CCGT CCS	5%	1	27	15%	35%			0%
16		OCGT old	8%	1	13	15%	30%			0%
17		OCGT new	5%	1	13	15%	30%			0%
18	Light oil	-	8%	1	13	15%	35%			0%
19	Heavy oil	old 1	10%	1	27	15%	35%			0%
20		old 2	10%	1	27	15%	35%			0%
21	Oil shale	old	10%	1	27	15%	40%			0%
22		new	7.50%	1	27	15%	40%			0%

Table 9: Additional economic parameters for TPPs from the common database

Start-up fuel consumption - cold start	Start-up fix cost (e.g. wear) cold start	Start-up fuel consumption - hot start	Start-up fix cost (e.g. wear) hot start		
Net GJ /MW. start	€ /MW. start	Net GJ /MW. start	€ /MW. start	Transition time [h] from hot to warm	Transition time [h] from hot to cold
21.0	94	10.5	49	12	72
21.0	81	10.5	42	12	72
21.0	57	10.5	31	12	72
21.0	81	10.5	42	12	72
21.0	94	10.5	49	12	72
21.0	81	10.5	42	12	72
21.0	57	10.5	31	12	72
21.0	81	10.5	42	12	72
9.7	70	4.1	33	8	48
9.7	59	4.1	28	8	48
9.7	79	4.1	44	8	48
9.7	62	4.1	27	8	48
9.7	36	4.1	22	8	48
9.7	62	4.1	27	8	48
0.3	52	0.2	31	2	3
0.3	24	0.2	17	2	3
0.3	38	0.2	24	2	3
9.7	94	4.1	49	8	48
9.7	81	4.1	42	8	48
21.0	88	10.5	46	12	72
21.0	57	10.5	31	12	72

2.4 Fuel and CO_2 prices

For fuel prices and CO_2 prices, we needed to use consistent, comparable generation costs in all countries and market areas analyzed. For this purpose, we applied the 2025 fuel prices from the TYNDP 2018 common database (Table 10).

Table 10: Fuel and CO_2 prices in 2025 Coal Before Gas scenario

Commodity	*Unit*	Price
Nuclear	***€/net GJ***	0.47
Lignite		1.1
Hard coal		2.5
Gas		7.4
Light oil		18.7
Heavy oil		15.3
Oil shale		2.3
CO_2 price	***€/ton***	25.7

For the same reason, we assumed the CO_2 price to be the same as applied for TYNDP 2018. We used this level of CO_2 price for all the SEE countries.

While the CO_2 tax must be applied for all EU member states, after discussion with the EMI members, we decided to apply the CO_2 tax to all the SEE countries. This approach assures consistency of the operating costs level and comparable results with ENTSO-E projects. If we had modeled some countries with the EU ETS price, and some without, it would have created a substantial advantage for those countries not in the ETS system. Also, it seems reasonable that all SEE countries will be part of the EU ETS by 2025.

2.5 Neighboring power systems

As mentioned above, the SEE region in this project considers 11 power systems in detail. These power systems are modeled on a plant-by-plant level of detail, with a simplified representation of the transmission network.

In order to improve modeling accuracy and to adequately model the exchange of electricity between the SEE region and neighboring power systems, it is important to include them in the regional market model. To model the neighboring systems and capture the influence of the pan-European electricity market, this project has used the publicly available ENTSO-E data from the Ten Year Network Development Plan (TYNDP) and Midterm Adequacy Forecast (MAF).

We chose two approaches to model the neighboring systems:

- external electricity markets (for Central Europe, Italy and Turkey), and
- power systems modeled on a technology level (for Hungary).

We explain each of these approaches below.

2.5.1 External electricity markets

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

Our modeling used assumptions of wholesale market prices in 2025 from the TYNDP 2018 Scenario Building Outputs data file, which contains average yearly marginal cost indicators for each country, depending on the climatic conditions and level of hydrology. Table 11 shows our assumptions for average yearly prices on the modelled external markets based on 3 selected climatic years (1982, 1984 and 2007) analyzed in ENTSO-E TYNDP2018.

Table 11: Average 2025 yearly price on external markets for different climate conditions

Market	Price (€/MWh)		
	Normal (1984)	Dry (1982)	Wet (2007)
Central Europe	54.08	51.48	49.74
Italy	56.99	54.09	56.42
Turkey	61.16	58.98	63.20

In order to model the variation of hourly prices throughout the year, we have used a time series of observed market prices at respective electricity markets in the last three years to create an hourly profile. Thus, the hourly profile of electricity prices for Central Europe is based on the observed market prices from 2016 to 2018 on the European Energy Exchange (EEX), i.e. EPEX SPOT prices for Germany and Austria. For the Italian power market, we have used a time series of observed market prices at the Italian Power Exchange (IPEX), and for Turkey the modelled hourly prices are based on the observed market on EXIST (Energy Exchange Istanbul).

2.5.2 Power systems modeled on a technology level

To take into account the exchange of power between the SEE region and Hungarian market area, we included the Hungarian power system in the regional market model. The EMI modeled the Hungarian power system by technology clusters (e.g., hydro, thermal, nuclear and RES), rather than plant by plant. We based the inputs for modeling on data from the TYNDP 2018 scenario Best Estimate 2025. The Figures below show the inputs for the Hungarian market area in terms of hourly load, monthly consumption, and production. This is the same format we use to present the data inputs for all 11 EMI TSOs.

Hungarian market area – Demand

In 2025, the peak load in Hungarian market area is expected to reach approximately 6,440 MW, with minimum loads below half this value, about 3,000 MW (Figure 14).

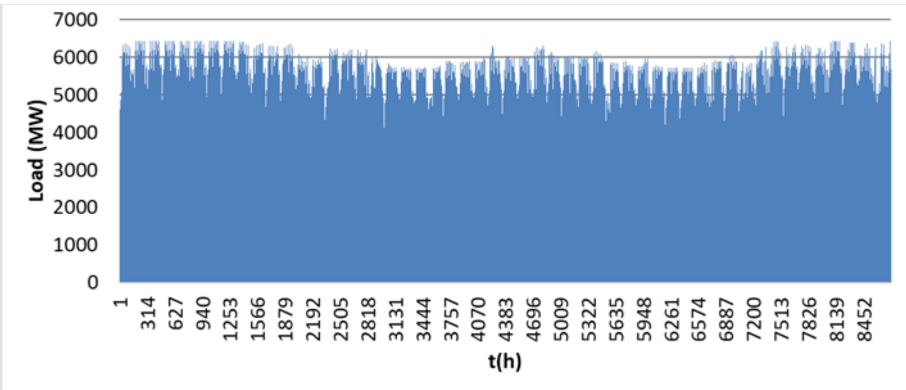


Figure 14: Hourly load profile in 2025 – Hungarian market area

The Hungarian monthly energy profile shows a significant seasonality, with September being significantly lower in consumption (Figure 15).

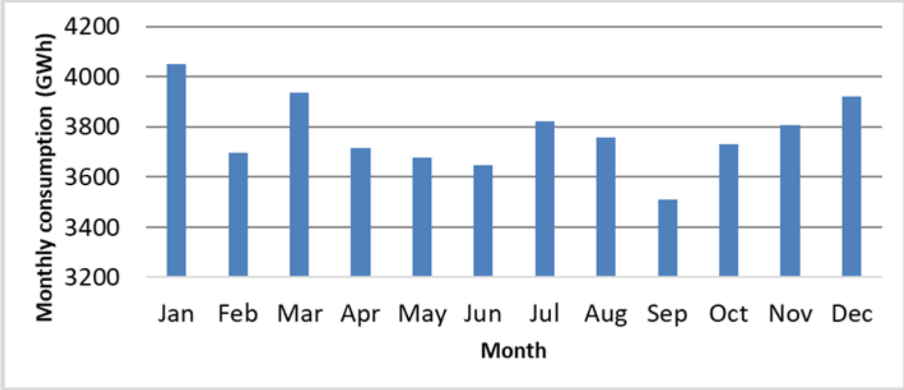


Figure 15: Monthly energy consumption (GWh) for 2025 – Hungarian market area

Hungarian market area – Production

The Hungarian power system in 2025 will be dominated by fossil-fuel TPPs, which will hold 43% of the installed capacity. Further, 33% will be in nuclear power, where the most dominant power plant in the Hungarian market area, NPP Pakš, is located close to the border with the HOPS market area, and is expected to have 3,014 MW of installed power in 2025. The remaining 24% will be shared between 1,400 MW in solar power plants, and 800 MW of wind. HPPs as well as other types of generation capacities are not expected to be in the Hungarian power system in 2025. Installed capacities in MWs are provided in Table 12, while shares by technology are depicted in Figure 16.

Table 12: Installed capacities per technology in 2025 – Hungarian market area

Technology	Installed capacity (MW)
Thermal - lignite	682
Thermal - gas	2785
Thermal - hard coal	152
Thermal - light oil	410
Nuclear	3014
Wind	800/1000[5]
Solar	1400/2000[5]

[5] Installed capacities expected in Baseline/High RES Scenarios

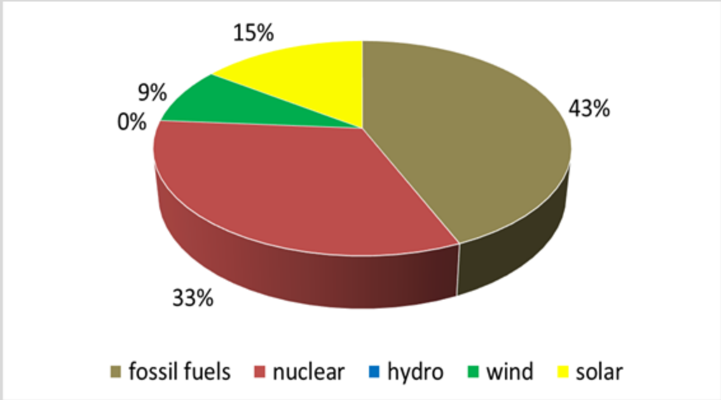


Figure 16: Installed capacity per fuel type in 2025 – Hungarian market area

Hungarian market area – Network transfer capacities

Table 13 shows the interconnection capacities between the Hungarian market area and the neighboring SEE market areas of HOPS, EMS and TransElectrica, which are expected to remain largely unchanged in 2025 compared to today. At present, no interconnection between the ELES and Hungarian market areas exists, and we expect a new transmission line between them in 2021.

Table 13: Network transfer capacities in 2025 – Hungarian market area

NTC (MW) in 2025	Win/Aut	Sum/Spr
Season	Win/Aut	Sum/Spr
RS - HU	600	600
HU - RS	600	600
RO - HU	1100	1100
HU - RO	1000	1000
HR - HU	1000	1000
HU - HR	1200	1200
SI - HU	1200	1200
HU - SI	1200	1200

These two approaches enable the EMI analysis to capture the surrounding market areas in the analysis, albeit in less detail than for each of the EMI market areas.

3 METHODOLOGICAL APPROACH AND ANALYZED SCENARIOS

3.1 Methodological approach

The objective of this work is to analyze and quantify the impacts of electricity market integration in the SEE region, with the focus on the wholesale day-ahead market, and specifically on the impacts of such integration on electricity prices. To capture and project the results of such integration, this project prepared a complex regional electricity market model that includes all existing and planned generating capacities in SEE with a simplified representation of the transmission network.

Market integration will include a transition from explicit to implicit allocation of transmission capacities. With explicit trading, transmission capacity and energy are traded separately and market participants wanting to sell power over a bidding zone border need to nominate and acquire the transmission capacity required to do so. With implicit allocation, electricity and transmission capacity are traded simultaneously, and cross-zonal trade is possible for market participants without explicitly acquiring transmission capacity under the condition that interconnectors are not congested.

The implicit allocation of transmission capacities enables more efficient utilization of available net transmission capacities (NTCs). This is the conclusion of several reports[6] conducted for the countries and borders already implementing "market coupling". In the case of the SEE region, analyses carried out by the ECRB[7] showed that in 2015 and 2016, the utilization of NTCs was less than 50%. Having this in mind, our initial, Baseline Scenario with non-coupled markets, is based on the assumption of availability of 50% of the NTCs, to capture the inefficiency of transmission utilization between those market areas, while scenarios with partial and full market coupling include availability of 100% of NTCs on the coupled borders. This assumption is one of the major distinctions between coupled and non-coupled markets in the EMI analysis.

For the purpose of these analyses and simulation of zonal market operation among EMI WG members, the NTC values provided by the TSOs have been harmonized with the model developed in Antares, and the consolidated values used in our study are given in Table 14. In some cases, there are seasonal variations.

We would note that over a longer period, if there is an active, integrated market for power between one country and another, and between one region and the neighboring one, with sufficient price differentials, we would expect either new transmission (e.g., upgrades) to existing rights of way; entirely new lines; or enhancements in transmission technology that would allow for greater flows in both directions with the existing configuration.

[6] ACER/CEER – Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2017 – Electricity Wholesale Markets Volume, 22.10.2018

[7] Wholesale Electricity Market Monitoring Report for the Energy Community Contracting Parties, EnCS, December 2018

Table 14: Summarized NTC values in 2025 (MW)

NTC (MW) in 2025	Win/Aut	Sum/Spr
AL - GR	250	250
AL - ME	500	500
AL - MK	400	400
AL - XK	650	610
CE_HU - HU	800	800
CE_SI - SI	950	950
BA - HR	1200	1050
BA - ME	600	600
BA - RS	600	600
BG - GR	1350	1350
BG - MK	500	500
BG - RO	1200	1200
BG - RS	400	400
BG - TR_BG	900	900
GR - AL	250	250
GR - BG	800	800
GR - IT	500	500
GR - MK	650	1000
GR - TR_GR	433	366
HR - BA	1000	1000
HR - HU	1000	1000
HR - RS	500	500
HR - SI	1500	1000
HU - CE_HU	800	800
HU - HR	1200	1200
HU - RO	1000	1000
HU - RS	600	600
HU - SI	1200	1200
IT - GR	500	500
IT - ME	600	600
IT - SI	1650	1650

NTC (MW) in 2025	Win/Aut	Sum/Spr
ME - AL	500	500
ME - BA	600	600
ME - IT	600	600
ME - RS	300	300
ME - XK	300	300
MK - AL	600	600
MK - BG	400	400
MK - GR	650	1000
MK - RS	200	200
MK - XK	200	200
RO - BG	1100	1100
RO - HU	1100	1100
RO - RS	1000	1000
RS - BA	600	600
RS - BG	400	400
RS - HR	500	500
RS - HU	600	600
RS - ME	300	300
RS - MK	325	325
RS - RO	800	800
RS - XK	300	300
SI - CE_SI	950	950
SI - HR	1500	1100
SI - HU	1200	1200
SI - IT	1600	1600
TR_BG - BG	500	500
TR_GR - GR	466	400
XK - AL	650	610
XK - ME	300	300
XK - MK	325	325
XK - RS	400	400

To support the move towards the integration of SEE power markets, this report analyzes a number of key impacts and benefits of such markets, including the impact on:

- market prices,
- generation mix,
- carbon emissions,
- electricity imports and exports, and
- socio-economic welfare.

We have prepared the regional electricity market model using the open source Antares tool[8]. The model includes the power systems of all EMI WG members and the neighboring countries/markets, and includes generation capacities and a simplified representation of the transmission network and cross-border capacities. Appendix II provides more details on our modeling approach.

We deployed a single, internally consistent regional market model (Antares) to represent the generating and transmission capacities for the selected modeling year – 2025. This year provides an appropriate period over which significant changes can take place in the network, regulations, generation and other aspects of the SEE electricity system, and one that is within the current planning horizon and implementation plans of the EMI members.

To quantify and analyze the impacts of market integration, this EMI report compares separated (non-coupled) with more integrated (coupled) markets. While we do not expect separated markets (SM) to exist in SEE in 2025, this scenario provides a foundation against which to measure the benefits of market integration. Our analysis provides these primary results of the market simulations:

- Overview of electricity balance (generation, consumption, imports and exports),
- Cross-border power exchanges for each border in the region,
- Price convergence, location and hours of market congestions in the SEE region (entirely used NTCs between areas with price difference),
- Amount and cost of CO_2 emissions for each market area,
- Total generation cost for each market area,
- Average wholesale electricity prices for each market area
- Social and Economic Welfare (SEW) changes for each market area.

The benefits quantified in this study should be considered conservative for a number of reasons, as described in the "Caveats" section of the Executive Summary.

3.2 Analyzed scenarios

In all analyzed scenarios with and without market coupling, and with partial regional coupling, certain assumptions are the same, i.e. assumptions regarding existing planned generation capacities in the region with detailed technical and economic inputs; fuel and CO_2 emissions prices; forecasted demand; cross-border transmission capacities; and prices on external electricity markets.

However, to assess the impact of changes in the most important assumptions on the results, the EMI proposed several additional scenarios, based on our consultations with EMI participants. These scenarios needed to be plausible but not too numerous, since we were not attempting to measure the precise impact of such changes, but rather determine whether the impacts and benefits of those changes (including greater market integration) would be meaningful. We also needed to ensure that we could carry out the analysis in the time frame specified in the scope of work, which envisioned completing the work by Fall 2019 and transferring the Antares model to the EMI members. Thus, in

[8] Antares is a probabilistic sequential hourly simulation tool that calculates all variables related to the system operation (generation level for each unit, flow through of each line). In addition, the tool gives an account of the CO_2 emissions, as well as an assessment of the economic performance of the whole system (various estimates such as operation costs, LMP, congestion fees, etc.)

addition to the Baseline Scenario, the EMI proposed to model and analyze twelve (12) different scenarios, as described below.

3.2.1 Different levels of market coupling

In order to analyze and quantify the impacts of electricity market integration in the SEE region, it is necessary to evaluate both the two ends of the spectrum – entirely separated markets and fully integrated markets, and something in between. We call these scenarios:

- Separated markets (SM) without market coupling (MC),
- Partial market coupling (PMC) and
- Full market coupling (FMC).

Currently there are two coupling projects in parallel operation, namely the Multi-Regional Coupling (MRC) and 4M Market Coupling (4M MC) project (Figure 17). The ESO EAD market area is a member of the MRC, and connected to the MRC calculation via the common PCR EUPHEMIA algorithm, but without interconnection capacities.

In addition, ADMIE/IPTO market area is reforming its electricity market, and is expected to be coupled with Italy in 2020 through the GR-IT interconnector. Since there are regulations (CACM NC[9]) which require the integration of these coupling projects before 2025, the EMI has modeled the borders of all EU member states as coupled in all scenarios.

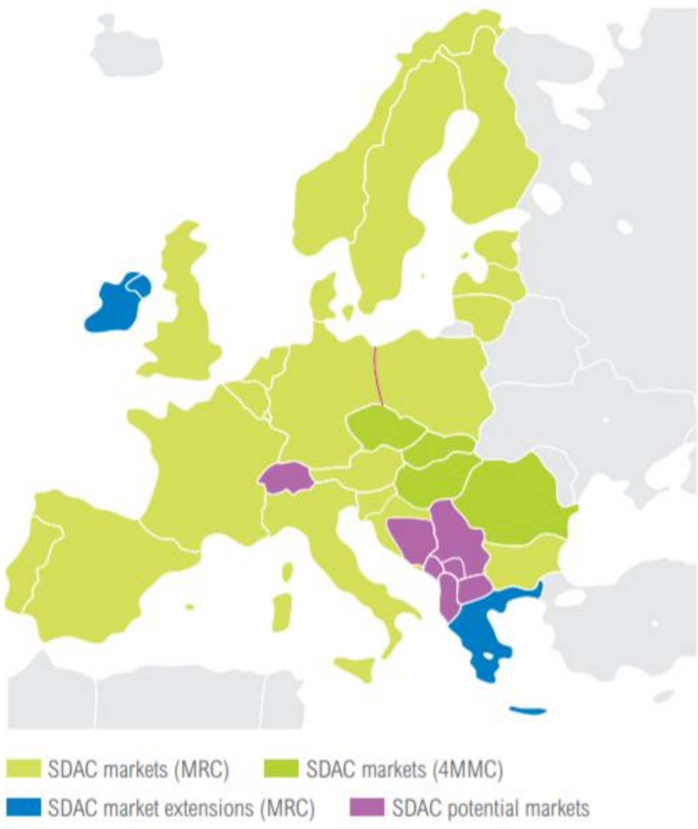


Figure 17: Single day-ahead market couplings (status July 2018, source ENTSO-E)

[9] Capacity Allocation and Congestion Management Network Code, ENTSO-E

For the WB6, couplings will happen in different time frames, and the region may not be fully integrated by 2025. Therefore, in consultation with the EMI members, we decided to analyze one intermediate step between the current state and full market integration, i.e., a partial market coupling scenario (Figure 18), or PMC, which assumes a lower level of market integration in the SEE region. Our PMC scenario, with four groups of power markets, is a basis for comparison of one scenario to another, and a way to quantify the impacts while the region is moving towards full integration. This scenario may also represent changes that could occur before 2025.

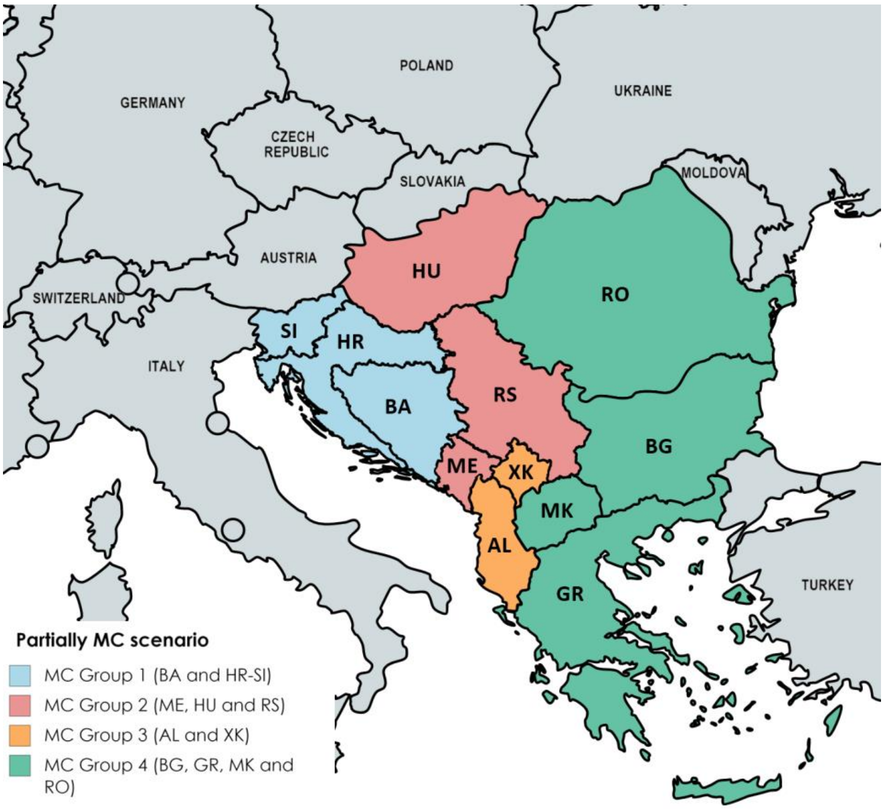


Figure 18: EMI Partial market coupling (PMC) scenario groups and market areas

As depicted in Figure 18, this PMC scenario assumes four (4) groups of market couplings as follows:

- Market coupling of the NOSBiH, HOPS and ELES market areas,
- Market coupling of the CGES, Hungarian and EMS market areas,
- Market coupling of the OST and KOSTT market areas, and
- Market coupling of the ESO EAD, ADMIE/IPTO, MEPSO and TransElectrica market areas.

Given that we assume the market coupling of all EU member states in all scenarios, this PMC scenario in fact enables coupling of almost all the EMI WG members with the Multi-Regional Coupling (MRC) project for Pan-European market coupling, at least on one border. As mentioned, this is considered a transitional situation; in the full market coupling scenario, all EMI WG member borders are mutually coupled, and coupled with the MRC.

3.2.2 Different hydrological conditions

Hydrological conditions are critical for the SEE countries with a high share of hydro generation, particularly for the OST market area. Thus, we evaluated scenarios with both normal and dry hydrological conditions, along with different levels of market couplings. One set of our analyses evaluates these conditions:

- Dry hydrological conditions with SM,
- Dry hydrological conditions with PMC and
- Dry hydrological conditions with FMC.

Appendix I provides our assumptions on generation from hydro power plants in dry hydrological conditions for each country/market area.

3.2.3 Different levels of RES penetration and demand growth

EMI members suggested that we analyze different level of renewable energy sources (e.g., wind and solar) and different levels of demand growth. We anticipated that the combination of high RES penetration and low demand could present a challenge, given the increase this would represent in the share of RES in the generation mix, so we decided to analyze scenarios that combine these two assumptions with different levels of market coupling in the SEE region as follows:

- High level of RES penetration and low demand with SM,
- High level of RES penetration and low demand with PMC, and
- High level of RES penetration and low demand with FMC.

The assumptions we used for the high level of RES penetration and low demand in these scenarios are shown in section 2.1 and Appendix I for each country/market area.

3.2.4 Different levels of RES penetration, demand growth and hydrological conditions

Finally, we also analyzed – in consultation with EMI members - a set of scenarios that varied all three important elements – RES penetration, demand growth and hydrological conditions:

- High RES penetration, low demand and dry conditions with SM,
- High RES penetration, low demand and dry conditions with PMC and
- High RES penetration, low demand and dry conditions with FMC.

This approach provides full comparability of analytic results across a number of key variables, all of which could plausibly occur, and gives the EMI members a full spectrum of results for each country/market area.

4 MARKET ANALYSES RESULTS

Table 15 below provides an overview of all 12 EMI scenarios, with their scenario-specific assumptions regarding the level of market coupling, hydrological conditions, RES penetration and demand growth. This chapter summarizes the results of the analysis for these 12 Scenarios.

Table 15: Set of EMI scenarios for 2025, with scenario-specific assumptions

No	Scenario	Market coupling	Hydrology	RES	Demand
1)	**Baseline Scenario with separated markets (SM)**	separated (non-coupled) markets	normal hydrology	base level of RES penetration	base demand growth
2)	**Baseline Scenario with partial market coupling (PMC)**	partially coupled markets in 4 groups	normal hydrology	base level of RES penetration	base demand growth
3)	**Baseline Scenario with full market coupling (FMC)**	market coupling of all EMI market areas	normal hydrology	base level of RES penetration	base demand growth
4)	**Dry hydrological conditions with SM**	separated (non-coupled) markets	dry hydrology	base level of RES penetration	base demand growth
5)	**Dry hydrological conditions with PMC**	partially coupled markets in 4 groups	dry hydrology	base level of RES penetration	base demand growth
6)	**Dry hydrological conditions with FMC**	market coupling of all EMI market areas	dry hydrology	base level of RES penetration	base demand growth
7)	**High level of RES penetration and low demand with SM**	separated (non-coupled) markets	normal hydrology	high level of RES penetration	low demand growth
8)	**High level of RES penetration and low demand with PMC**	partially coupled markets in 4 groups	normal hydrology	high level of RES penetration	low demand growth
9)	**High level of RES penetration and low demand with FMC**	market coupling of all EMI market areas	normal hydrology	high level of RES penetration	low demand growth
10)	**High level of RES penetration, low demand and dry hydrological conditions with SM**	separated (non-coupled) markets	dry hydrology	high level of RES penetration	low demand growth
11)	**High level of RES penetration, low demand and dry hydrological conditions with PMC**	partially coupled markets in 4 groups	dry hydrology	high level of RES penetration	low demand growth
12)	**High level of RES penetration, low demand and dry hydrological conditions with FMC**	market coupling of all EMI market areas	dry hydrology	high level of RES penetration	low demand growth

4.1 Baseline Scenarios

4.1.1 Separated (non-coupled) markets (SM)

We depict the electricity generation mix and consumption in the SEE region for separated markets (SM) in the baseline scenario in Figure 19. Total generation in the SEE region in 2025 is around 283 TWh, while total consumption equals 273.82 TWh, enabling exports from the region. Across the region, annual generation varies substantially, from 4.15 TWh in ME to almost 68 TWh in RO. Clearly certain markets are greater importers (GR, HR) while others have high exports (BA, BG, and RO).

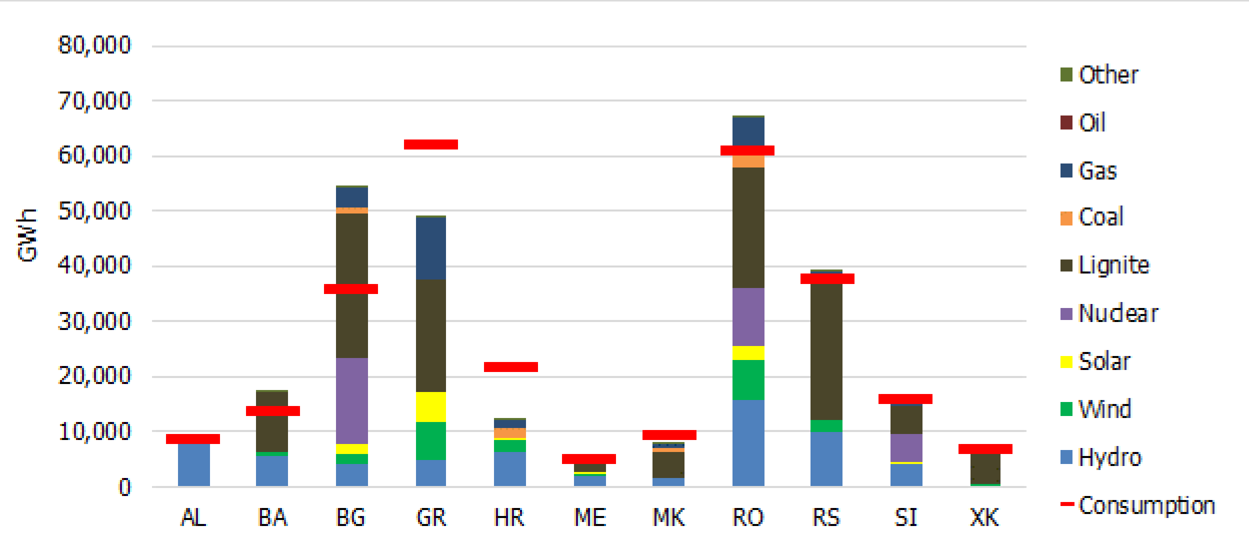


Figure 19: Electricity generation mix and consumption by market area in 2025 (Baseline scenario – SM)

Below we show the detailed electricity generation mix by market area in the SM case (Table 16).

Table 16: Electricity generation mix by market area in 2025 (Baseline scenario – SM)

Yearly generation (TWh)	AL	BA	BG	GR	HR	ME	MK	RO	RS	SI	XK	SEE
HPP	8.40	5.84	4.43	5.16	6.43	1.93	1.47	15.89	10.05	4.85	0.17	**64.62**
TPP lignite	0.00	10.67	26.09	20.21	0.00	1.51	4.67	22.04	26.64	5.16	6.47	**123.46**
TPP coal	0.00	0.00	1.15	0.00	1.76	0.00	0.58	3.10	0.00	0.00	0.00	**6.59**
TPP gas	0.00	0.00	3.64	11.20	1.28	0.00	0.79	5.87	0.34	0.45	0.00	**23.57**
TPP oil	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	**0.02**
TPP other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.85	0.00	0.00	0.00	**0.85**
Nuclear	0.00	0.00	15.43	0.00	0.00	0.00	0.00	10.44	0.00	4.90	0.00	**30.77**
Solar	0.07	0.07	1.88	5.33	0.56	0.41	0.09	2.52	0.01	0.39	0.08	**11.42**
Wind	0.15	0.62	1.77	7.01	2.27	0.30	0.18	7.06	2.17	0.04	0.30	**21.86**
TOTAL	**8.61**	**17.19**	**54.40**	**48.93**	**12.30**	**4.15**	**7.79**	**67.77**	**39.21**	**15.79**	**7.02**	**283.16**

In SEE as a whole, fossil fuels (TPPs) play the largest role, though in the OST, HOPS and CGES market areas, HPPs have the highest share. Also, in the TransElectrica, ELES and ESO EAD market areas, nuclear has a high share. In RES generation (wind and solar), GR and RO are the leaders, with 12 TWh and 9.5 TWh, respectively. KOSTT and OST have the least diversified mixes, with almost all generation from TPPs and HPPs, respectively.

We present the 2025 electricity balances (i.e. yearly consumption, generation and exchange values) for each SEE market area in the SM scenario in Table 17. The ESO EAD and TransElectrica market areas would have the highest positive net interchange, 19 TWh and 7.2 TWh respectively, meaning they would be the biggest net exporters in the SEE region in this scenario, while ADMIE/IPTO and HOPS market area would be significant net importers, with around 12.6 TWh and 9 TWh, respectively. In relative terms, ESO EAD market area is the largest exporter (export is almost 54% of its demand), while HOPS market area is the largest importer, with import higher than 40% of its demand. The OST and ELES market areas would be almost balanced on an annual level. The SEE region as a whole would export around 9.3 TWh to the neighboring power systems (note that here, the SEE region does not include Hungary, as it is not an EMI member).

Table 17: Electricity balance in 2025 (Baseline scenario – SM)

Electricity balance	Cons. (GWh)	Gener. (GWh)	Pump load (GWh)	Custom. load (GWh)	Imports (GWh)	Exports (GWh)	Transit (GWh)	Net inter-change (GWh)	Net import / export share (%)
AL	8430	8612	0	8430	1472	1654	638	182	2.2%
BA	13448	17191	163	13285	289	4032	672	3743	27.8%
BG	35396	54397	334	35062	0	19002	2489	19002	53.7%
GR	61545	48932	324	61248	12627	14	3998	-12614	-20.5%
HR	21433	12295	379	21054	9247	109	1395	-9138	-42.6%
ME	4774	4147	0	4774	1237	611	3263	-626	-13.1%
MK	8890	7787	0	8890	1231	129	2528	-1103	-12.4%
RO	60571	67771	0	60571	127	7326	2414	7200	11.9%
RS	37253	39209	350	36904	678	2632	2965	1954	5.2%
SI	15741	15793	889	14852	994	1045	12786	51	0.3%
XK	6339	7020	0	6340	420	1101	870	681	10.7%
SEE	273822	283153	2439	271410	5613	14945		9332	3.4%

Consumption (in GWh) in the table above refers to total consumption, calculated by adding the customer load (demand) and load for pumped storage HPPs, and subtracting the energy not supplied (ENS, if it exists). Customer load is a predefined hourly input time series of demand. Pumped load values, as a result of simulations, changes through the different scenarios, based on the operation of pumped storage HPPs in pumping mode.

The generation presented in the table refers to the total generation calculated by summing the generation of all modelled power plants, without curtailed generation (if it exists).

We depict export and import values, as presented in Table 17, in Figure 20, with transits in Figure 21, and net interchanges in Figure 22. These charts also include the neighboring power systems. As can be seen, Hungary and Turkey mainly import electricity from the SEE region, Central Europe mainly exports electricity to the SEE region, and Italy is almost balanced with the SEE region, but with a high exchange during the year. This balance is expected given the assumed wholesale market prices of the neighboring markets (see chapter 2.5). The highest transit is in the ELES market area, due to borders with large importers such as Hungary and Croatia, and large exporters such as CE, also large energy exchanges with Italy in both directions. This assessment is consistent with the border flows shown in Table 19.

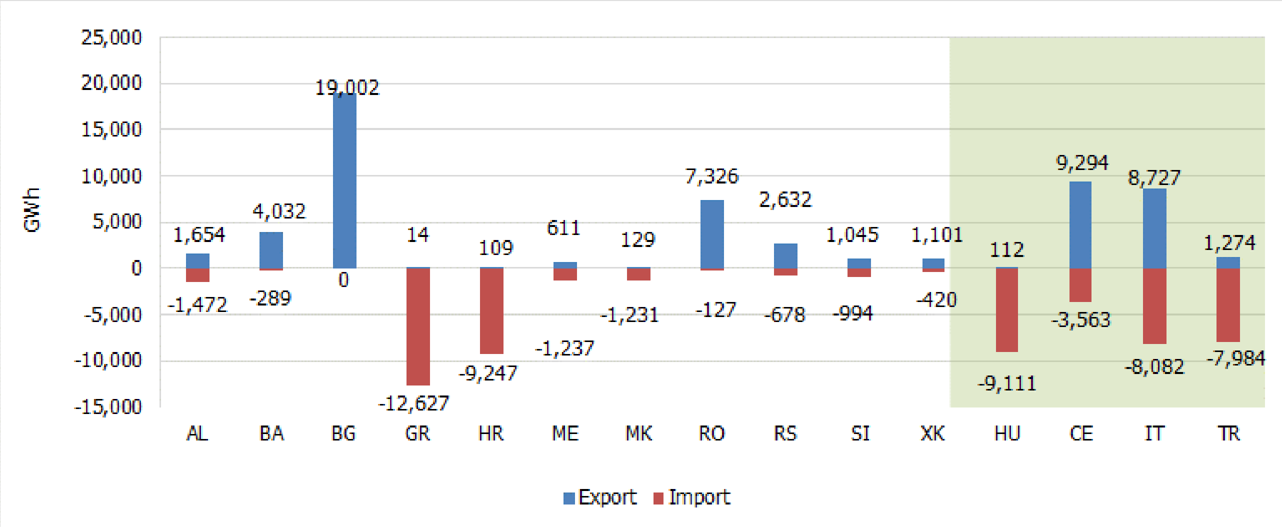


Figure 20: Imports and exports in 2025 (Baseline scenario – SM)

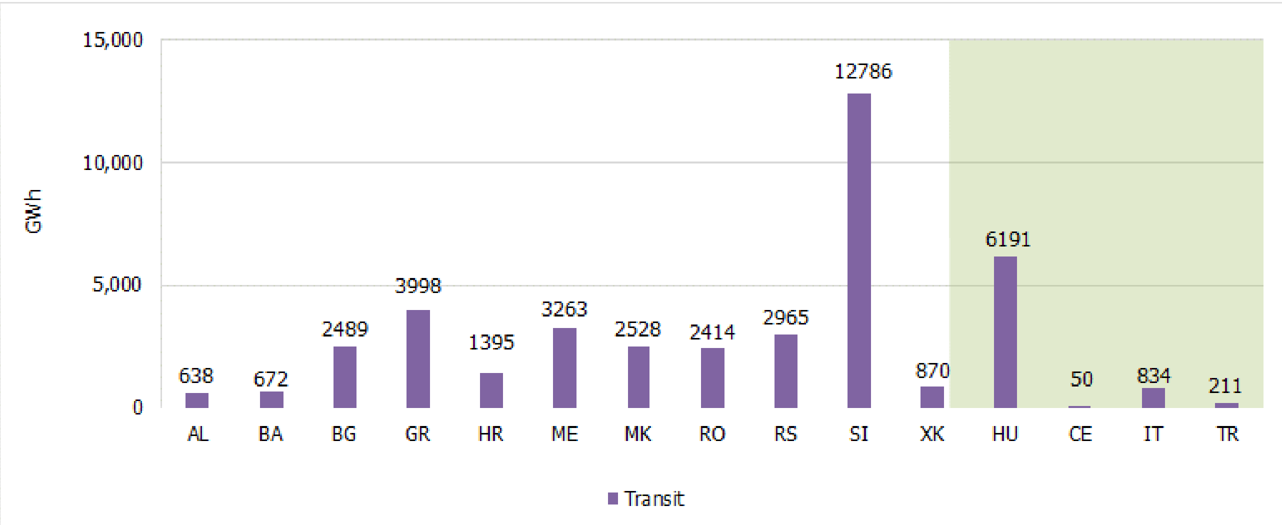


Figure 21: Transits in 2025 (Baseline scenario – SM)

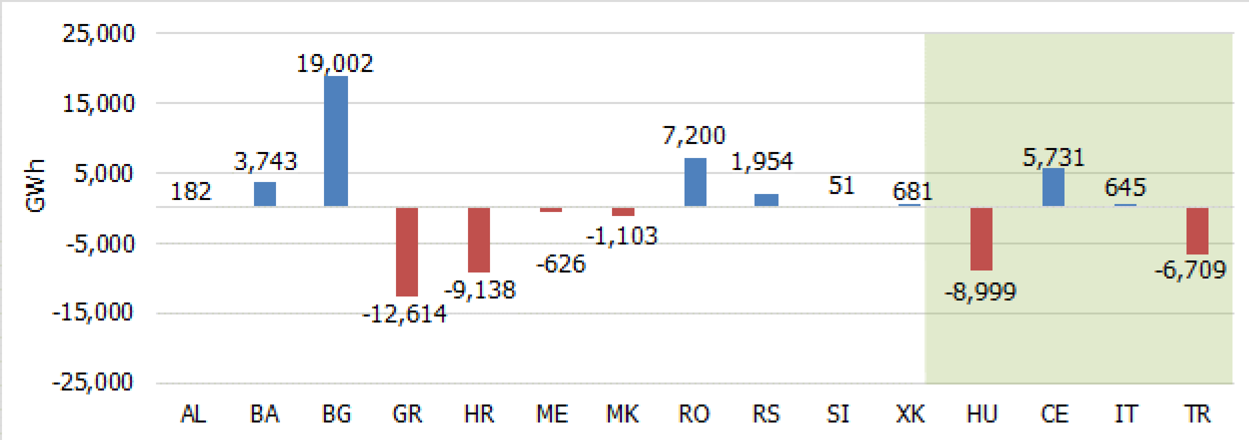


Figure 22: Net interchange in 2025 (Baseline scenario – SM)

While there are differences among the SEE market areas, a key factor is operating costs, for which we present annual simulation results in Table 18. Operating costs are based on variable costs including fuel, CO_2 and O&M costs of generating units. The market price is determined by the marginal operating cost of generation.

Average operating costs in the SEE region in 2025 will amount to 13.16 €/MWh in the baseline scenario. The highest operating costs are in the ADMIE/IPTO market area (17.43 €/MWh) where gas and coal TPPs have a high share. Table 18 also presents data about the yearly CO_2 emissions in the SEE region. The highest level of CO_2 emissions is expected to be in the TransElectrica and EMS market areas, due to their high share of coal (lignite) fired plants. Average total operating costs, which also include carbon costs, will amount in 2025 to 25.94 €/MWh in the SEE region. In terms of average total operating costs, the KOSTT market area has the highest value (36.57 €/MWh), followed by the MEPSO market area (34.1 €/MWh), because in these areas the majority of generation comes from coal TPPs, which are high CO_2 emitters.

In the SM scenario, the average SEE regional wholesale market price in 2025 is 56.12 €/MWh. These are not simple average prices but load-weighted average prices, since the latter presents a better indicator of overall system performance. Generally, wholesale electricity prices are harmonized in the region, but certain variations can be noticed. The highest average price would be in ADMIE/IPTO market area (63.79 €/MWh) followed by HOPS and ELES market areas, where average wholesale prices are somewhat higher than the rest of the region. The lowest price is in the TransElectrica market area (52.40 €/MWh), where prices are very close to the ESO EAD market area.

Table 18: Operating costs in 2025 (Baseline scenario – SM)

Operating costs without and with emissions costs	**AL**	**BA**	**BG**	**GR**	**HR**	**ME**	**MK**	**RO**	**RS**	**SI**	**XK**	**SEE**
Operating costs (mil. €)	0	168	849	853	117	23	119	945	399	162	91	**3,725**
CO_2 emissions (mil. tonne)	0	13	26	24	2	1	6	28	28	5	6	**141**
CO_2 emissions costs (mil. €)	0	344	681	610	57	39	147	732	715	131	166	**3,620**
Total operating costs (mil. €)	0	512	1,530	1,463	174	62	266	1,677	1,114	293	257	**7,345**
Average operating costs (€/MWh)	0.00	9.76	15.60	17.43	9.51	5.58	15.28	13.94	10.18	10.24	12.94	**13.16**
Average total operating costs (€/MWh)	0.00	29.76	28.12	29.89	14.16	14.87	34.11	24.74	28.42	18.53	36.57	**25.94**
Price (€/MWh)	55.51	54.15	52.42	63.79	58.23	54.21	54.61	52.40	53.28	56.53	54.89	**56.12**

Below, we analyze the results for yearly cross-border exchanges, and for loading and congestion.

When analyzing flows across borders, we note that the highest yearly flows (in GWh) will be on BG-GR border in 2025, as presented in Table 19, mostly from ESO EAD to ADMIE/IPTO. Next in line would be the significant flows between SI and a number of other countries and CE.

Table 19: Cross-Border exchange in GWh in 2025 (Baseline scenario – SM)

Market area	**Flow (GWh)**														
	AL	**BA**	**BG**	**GR**	**HR**	**HU**	**ME**	**MK**	**RO**	**RS**	**SI**	**XK**	**CE**	**IT**	**TR**
AL	-			609			720	533				430			
BA		-			3,220		1,017			467					
BG			-	10,998				1,765	1,968	757					6,003
GR	91		0	-				150						1,580	2,191
HR		118			-	290				35	1,061				
HU					2,216	-			378	181	1,880		1,649		
ME	732	283					-			111		329		2,419	
MK	418		13	2,142				-		32		52			
RO			1,652			6,189			-	1,899					
RS		560	216		1,430	1,444	485	789	194	-		479			
SI					3,776	3,174					-		1,964	4,917	
XK	869						417	524		160		-			
CE						4,205					5,139		-		
IT				2,000			1,861				5,700			-	
TR			608	877											-

To get better insights into the loading of particular borders, we show the percentage average cross-border loadings in Table 20. Cells colored in red show high flows i.e. loadings above 50%, while cells colored in green show low flows i.e. loadings at or below 10%. In the baseline scenario, the highest cross-border loading values occur on BG-GR border (93%, towards the ADMIE/IPTO market area) which is consistent to the high flows on that border shown in Table 13. High loadings also occur on

BG-MK (81%, towards MEPSO) and the BG-TR border (76%, towards Turkey). Generally, almost all links to the ADMIE/IPTO market area and Turkey will be highly loaded. Also, given EMS' central position in the EMI region, there are higher loadings at EMS' eastern and western borders, transferring energy from east to west and north (mainly from ESO EAD and TransElectrica to the HOPS and HU market areas).

Table 20: Cross-Border loading in percentages in 2025 (Baseline scenario – SM)

Market area	Loading (%)														
	AL	BA	BG	GR	HR	HU	ME	MK	RO	RS	SI	XK	CE	IT	TR
AL	-			56			33	30				16			
BA		-			66		39			18					
BG			-	93				81	19	43					76
GR	8		0	-				4						36	63
HR		3			-	3				2	10				
HU					21	-			4	7	18		24		
ME	34	11					-			9		25		46	
MK	16		1	59				-		4		6			
RO			17			64			-	43					
RS		21	12		65	55	37	56	6	-		37			
SI					33	30					-		24	35	
XK	32						32	37		9		-	0		
CE						60					62		-		
IT				46			36				40			-	
TR			14	23											-

We depict cross-border loadings in both directions (i.e., the sum of loadings in both directions) in Figure 23. The blue bars show borders coupled in all scenarios, while the orange bars show borders not -coupled in the SM scenario.

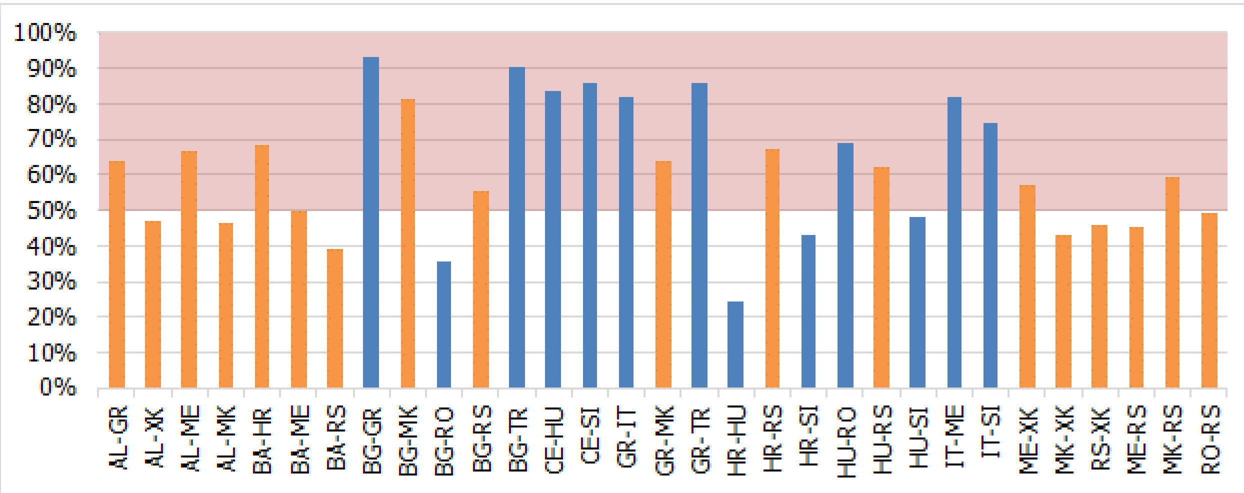


Figure 23: Cross-border loadings in both directions in 2025 (Baseline scenario – SM)

As Figure 23 shows, cross-border loadings in both directions will range from 22% to 93%. When analyzing borders on which we expect market couplings, we note high loadings in both directions (i.e., above 50%) on the AL-GR, AL-ME, BA-HR, BG-MK, BG-RS, GR-MK, HR-RS, HU-RS, ME-XK and MK-RS borders. We expect market couplings to lead to greater interchange and higher loadings.

The probability of cross-border congestion represents the number of hours in a year in which the flow on an interconnection equals or exceeds the modelled NTC, divided by the total number of hours (8760). We present the cross-border congestion probability for each border in Table 21. Red cells show high congestion probability (i.e., above 50%), while green cells show low congestion probability (i.e., below 10%). We note significant congestion probabilities, especially on the BG-GR, BG-MK, BG-TR and GR-TR borders, but only in one direction - from BG. Also, other borders with high congestion probabilities are the RS-HR, RS-HU and RS- MK borders (with flows from the EMS market area), which are not coupled in the SM scenario. This is expected, since large importing market areas are in the North-West and South of the EMI region.

Table 21: Cross-border congestion probability in 2025 (Baseline scenario – SM)

Market area	Congestion probability (%)														
	AL	BA	BG	GR	HR	HU	ME	MK	RO	RS	SI	XK	CE	IT	TR
AL	-			54			27	26				8			
BA		-			53		28			12					
BG			-	85				74	7	41					75
GR	8		0	-				2						36	62
HR		1			-	0				1	1				
HU					2	-			2	5	3		22		
ME	30	7					-			7		20		44	
MK	8		1	50				-		5		6			
RO			7			58			-	33					
RS		18	11		63	53	35	50	4	-		34			
SI					26	18					-		22	31	
XK	17						27	27		6		-	0		
CE						58					58		-		
IT				45			33				30			-	
TR			15	23											-

4.1.2 Partial market coupling (PMC)

We show the electricity generation mix and consumption in the SEE region for PMC in the baseline scenario in Figure 24. Total generation in the SEE region in 2025 amounts to 285.34 TWh, while total consumption amounts to 274.03 TWh. The highest generation is in the TransElectrica market area, while the CGES market area has the lowest electricity generation.

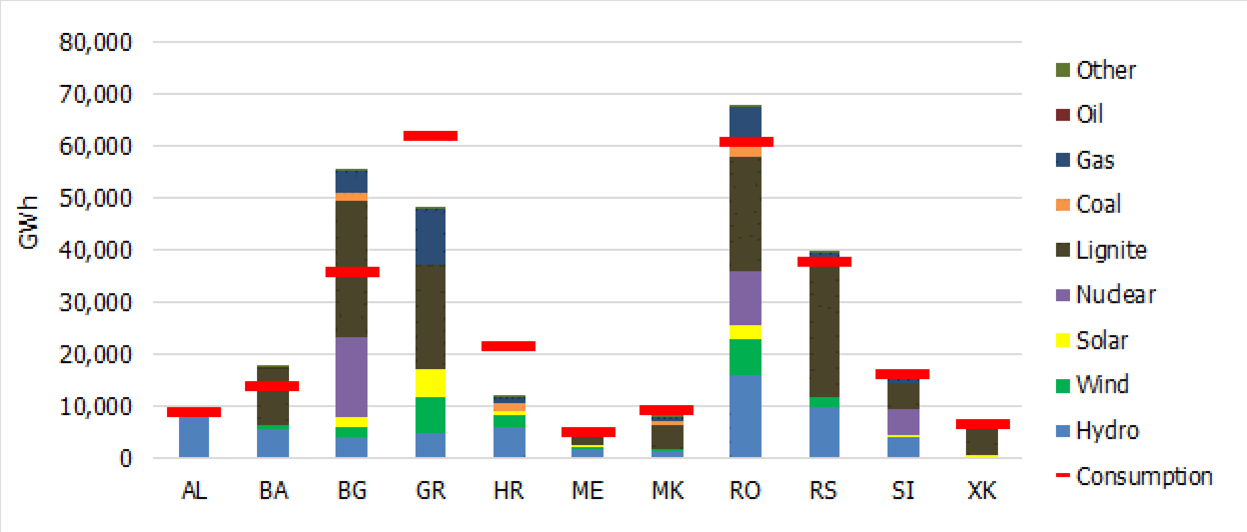


Figure 24: Electricity generation mix and consumption by market area in 2025 (Baseline scenario – PMC)

We present the 2025 electricity generation mix by market area in the PMC scenario in Table 22.

Table 22: Electricity generation mix by market area in 2025 (Baseline scenario – PMC)

Yearly generation (TWh)	AL	BA	BG	GR	HR	ME	MK	RO	RS	SI	XK	SEE
HPP	8.40	5.95	4.45	5.14	6.40	1.93	1.47	15.89	10.16	4.80	0.17	**64.77**
TPP lignite	0.00	11.32	26.30	20.04	0.00	1.51	4.70	22.15	26.85	5.17	6.53	**124.57**
TPP coal	0.00	0.00	1.29	0.00	1.74	0.00	0.64	3.35	0.00	0.00	0.00	**7.01**
TPP gas	0.00	0.00	4.21	10.60	1.24	0.00	0.83	6.21	0.50	0.42	0.00	**24.00**
TPP oil	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	**0.01**
TPP other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.93	0.00	0.00	0.00	**0.93**
Nuclear	0.00	0.00	15.43	0.00	0.00	0.00	0.00	10.44	0.00	4.90	0.00	**30.77**
Solar	0.07	0.07	1.88	5.33	0.56	0.41	0.09	2.52	0.01	0.39	0.08	**11.42**
Wind	0.15	0.62	1.77	7.01	2.27	0.30	0.18	7.06	2.17	0.04	0.30	**21.86**
TOTAL	**8.61**	**17.94**	**55.33**	**48.14**	**12.21**	**4.15**	**7.92**	**68.55**	**39.70**	**15.72**	**7.09**	**285.34**

Across SEE, fossil-fuel-powered TPPs have the highest share, except in the OST, HOPS and CGES market areas, where HPPs have the highest share. Also in the TransElectrica, ELES and ESO EAD market areas, nuclear generation has a notable share. The least diversified generation mix is in the KOSTT market area with almost all electricity from coal-powered TPPs. Regarding RES, GR and RO will lead the region, with 12.3 TWh and 9.5 TWh, respectively.

We show the projected electricity balances (i.e., yearly consumption, generation and exchange values) for each SEE market area in the baseline scenario with PMC in Table 23. In absolute values, the main net exporters are the ESO EAD and TransElectrica market areas, with 19.9 TWh and 8 TWh, respectively. The largest net importers are the ADMIE/IPTO and HOPS market area, with 13.4 TWh and 9.2 TWh, respectively, while the ELES and OST market are almost balanced. In relative terms, again the ESO EAD and HOPS market areas are the biggest exporters and importers.

Table 23: Electricity balance in 2025 (Baseline scenario – PMC)

Electricity balance	Cons. (GWh)	Gener. (GWh)	Pump load (GWh)	Custom. load (GWh)	Imports (GWh)	Exports (GWh)	Transit (GWh)	Net inter-change (GWh)	Net import / export share (%)
AL	8430	8612	0	8430	1610	1792	774	182	2.2%
BA	13591	17945	306	13285	202	4556	1090	4353	32.0%
BG	35429	55326	368	35062	0	19896	2970	19896	56.2%
GR	61535	48138	299	61248	13416	19	4210	-13397	-21.8%
HR	21393	12207	338	21054	9239	53	2640	-9186	-42.9%
ME	4774	4147	0	4774	1331	704	3307	-627	-13.1%
MK	8890	7916	0	8890	1190	217	4253	-973	-10.9%
RO	60571	68545	0	60571	110	8085	2141	7974	13.2%
RS	37405	39697	501	36904	614	2905	3808	2291	6.1%
SI	15672	15720	820	14852	974	1022	13447	48	0.3%
XK	6340	7087	0	6340	402	1149	1226	747	11.8%
SEE	274031	285339	2633	271410	29088	40397		11309	4.1%

Consumption presented in the table above refers to the total consumption calculated by adding the customer load (demand) and pump load for pumped storage HPPs, and subtracting the energy not supplied (ENS, if it exists). Customer load is a predefined hourly input time series of demand. Pumped load values change in the scenarios, based on the operation of pumped storage HPPs.

Generation presented in this table refers to the total generation calculated by adding the generation of all modelled power plants, while curtailed generation is not included (if it exists).

We present annual export, import, net interchange and transit values in Table 23, as well as Figure 25, Figure 26 and Figure 27, including the neighboring countries and regions in the PMC scenario.

Figure 27, shows that the highest power transit in the baseline PMC would be through ELES. Regarding neighboring power systems, HU and TR would mostly import electricity from SEE; Central Europe would mostly export electricity to SEE; and Italy would be almost balanced in relation to SEE, with dynamic trading during the year. We would expect this result considering the projected wholesale market prices in the neighboring regions (see chapter 2.5). The ELES market area would have the highest transit, due to borders with major importers such as HU and HR, and large exporters such as CE, plus large energy exchange with IT in both directions. This is in line with the border flows presented in Table 25.

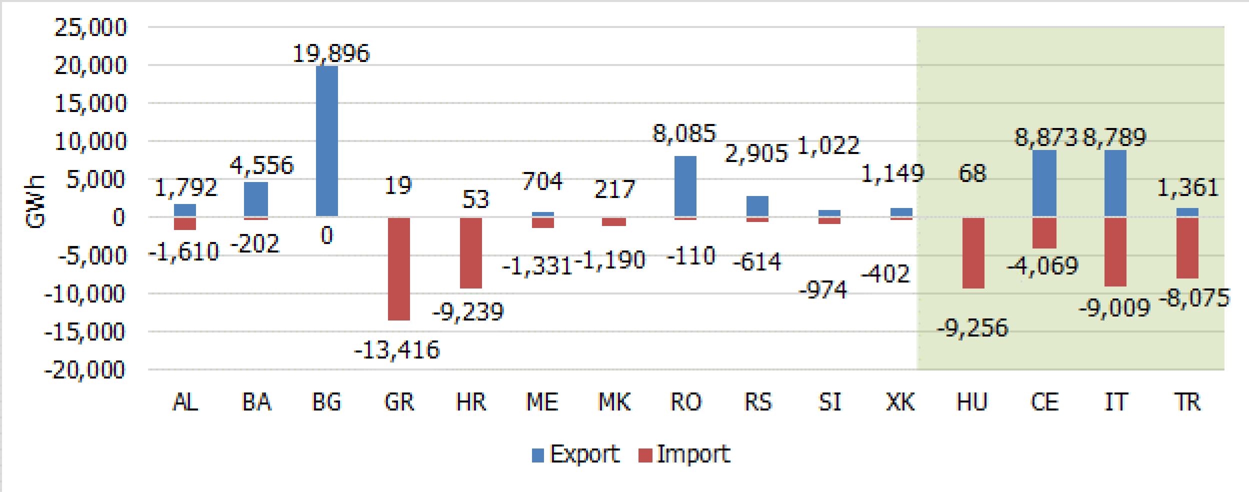


Figure 25: Imports and exports in 2025 (Baseline scenario – PMC)

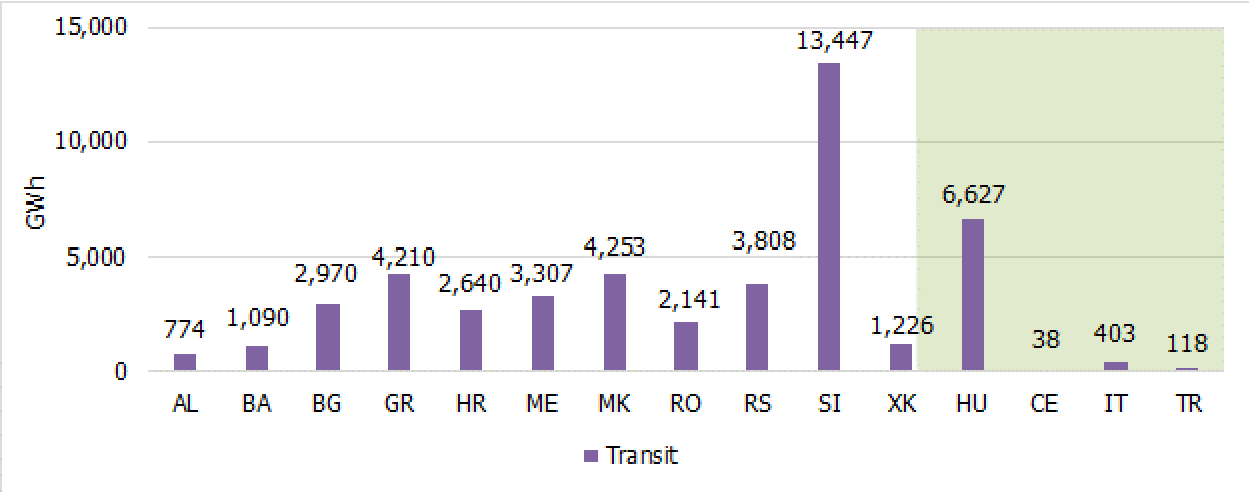


Figure 26: Transit in 2025 (Baseline scenario – PMC)

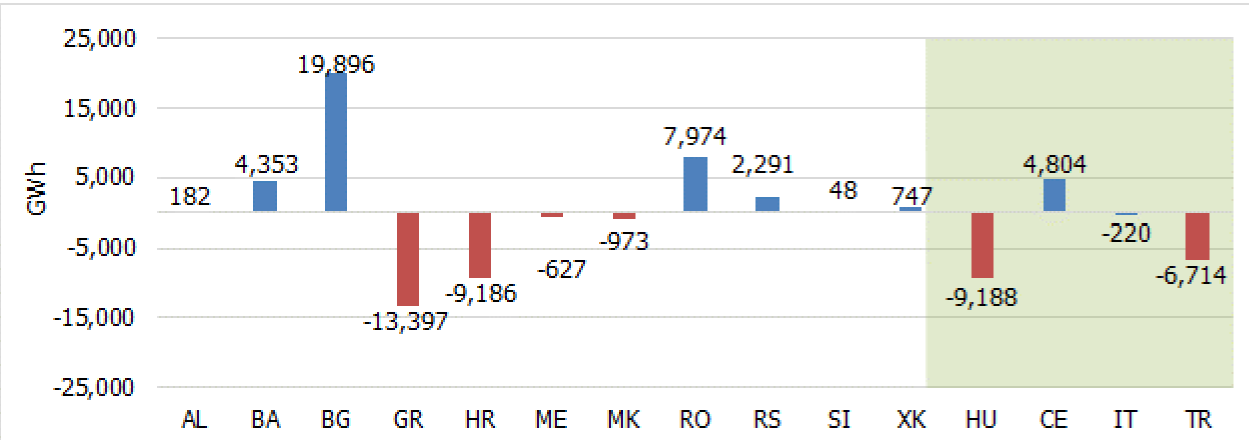


Figure 27: Net interchange in 2025 (Baseline – PMC)

An important difference among SEE market areas is operating costs, and we show yearly simulation results in Table 24. The market price is determined by the marginal cost of generation and the price in neighboring markets. We calculate operating costs based on the sum of variable costs, including the fuel, CO_2 and O&M costs of all generating units.

In this scenario, the average operating costs in SEE region amount to 13.24 €/MWh in 2025. The highest operating cost would be in the ADMIE/IPTO market area (17.02 €/MWh) where gas and coal TPPs have the highest share. Table 24 also presents data about the yearly level of CO_2 emissions in SEE. The highest level of CO_2 emissions would be in the TransElectrica and EMS markets area due to their high share of coal (lignite) fired plants. The average total operating costs, with CO_2 emission costs, would amount to 26.09 €/MWh in SEE in 2025. KOSTT would have the highest average operating cost (36.63 €/MWh) followed by MEPSO (34.38 €/MWh). This is mainly due to the thermal structure of these systems and carbon costs.

In the baseline scenario, with PMC, the average SEE regional wholesale market price is equal to 55.83 €/MWh. Generally, there are three price groups. The first group, with prices higher than average, includes the ADMIE/IPTO (59.84 €/MWh), HOPS (57.73 €/MWh), MEPSO (56.08 €/MWh) and OST (56.05 €/MWh) market areas. The second group, with prices close to or slightly below the average price, includes the NOSBiH, CGES, EMS, ELES and KOSTT areas, and the third consists of the ESO EAD (53.34 €/MWh) and TransElectrica (53.23 €/MWh) market areas, with the lowest prices.

Table 24: Operating costs in 2025 (Baseline scenario – PMC)

Operating costs without and with emissions costs	AL	BA	BG	GR	HR	ME	MK	RO	RS	SI	XK	SEE
Operating costs (mil. €)	0	178	883	819	114	23	123	974	410	160	92	**3,777**
CO_2 emissions (mil. tonne)	0	14	27	23	2	1	6	29	28	5	7	**143**
CO_2 emissions costs (mil. €)	0	365	694	599	56	39	149	744	722	131	168	**3,667**
Total operating costs (mil. €)	0	543	1,577	1,419	170	62	272	1,718	1,132	291	260	**7,444**
Average operating costs (€/MWh)	0.00	9.93	15.95	17.02	9.36	5.58	15.55	14.21	10.33	10.20	12.96	**13.24**
Average total operating costs (€/MWh)	0.00	30.26	28.50	29.47	13.96	14.86	34.38	25.06	28.52	18.52	36.63	**26.09**
Price (€/MWh)	56.05	55.62	53.34	59.84	57.73	55.29	56.08	53.23	54.81	55.94	55.34	**55.83**

We analyze the yearly cross-border exchanges, loading and congestions results for 2025 below.

The highest yearly border flows, in absolute values, would be at the BG-GR border, from the ESO EAD to ADMIE/IPTO's market areas, which is the same as in the SM scenario.

Table 25: Cross-border exchange in 2025 (Baseline scenario – PMC)

Market area	Flow (GWh)														
	AL	BA	BG	GR	HR	HU	ME	MK	RO	RS	SI	XK	CE	IT	TR
AL	-			511			830	517				708			
BA		-			4,966		504			176					
BG			-	10,803				3,676	1,679	831					5,878
GR	121		0	-				61						1,731	2,316
HR		92			-	477				25	2,099				
HU					1,887	-			424	339	2,129		1,925		
ME	733	441					-			192		345		2,300	
MK	554		0	3,618				-		144		154			
RO			2,063			5,844			-	2,319					
RS		760	235		1,275	2,361	818	693	149	-		422			
SI					3,750	3,157					-		2,182	5,380	
XK	976						507	495		397		-			
CE						4,045					4,866		-		
IT				1,886			1,979				5,326			-	
TR			671	808											-

We show the percentage loading value for each border in Table 25 to provide better insight into the use of the interconnection. Cells in red show high flows (i.e., loadings above 50%), while cells in green show low flows (i.e., below 10%). In this scenario the highest cross-border loading values are on the BG-GR border (92%, towards ADMIE/IPTO), consistent with the high flows in the previous table. High loadings would also occur on the BG-MK (84%, towards the MEPSO market area) and BG-TR borders (75%, towards Turkey). Generally, almost all links to ADMIE/IPTO market area and Turkey are highly loaded. The TransElectrica and ESO EAD areas have higher export loadings; EMS is highly loaded, with exports towards HR and HU; while GR and TR have high import loadings. This describes the main sources, sinks and directions of regional energy flow in the baseline PMC scenario.

Table 26: Cross-border loading in 2025 (Baseline scenario – PMC)

Market area	Loading (%)														
	AL	BA	BG	GR	HR	HU	ME	MK	RO	RS	SI	XK	CE	IT	TR
AL	-			47			38	30				13			
BA		-			51		19			7					
BG			-	92				84	16	48					75
GR	11		0	-				1						40	66
HR		1			-	5				1	19				
HU					18	-			5	6	20		28		
ME	34	17					-			7		26		44	
MK	21		0	50				-		16		18			
			21			61			-	53					
RS		29	13		58	45	31	49	4	-		32			
SI					33	30					-		26	38	
XK	18						39	35		23		-	0		
CE						58					59		-		
IT				43			38				37			-	
TR			15	21											-

Cross-border loadings in both directions (i.e., the sum of loadings in reference and counter-reference directions) are depicted in the Figure 28. The blue bars are borders that are coupled in all scenarios, while green bars are borders that are coupled only in the PMC scenario (AL-XK, BA-HR, BG-MK, GR-MK, HU-RS, ME-RS). Orange bars show non-coupled borders in the PMC scenario.

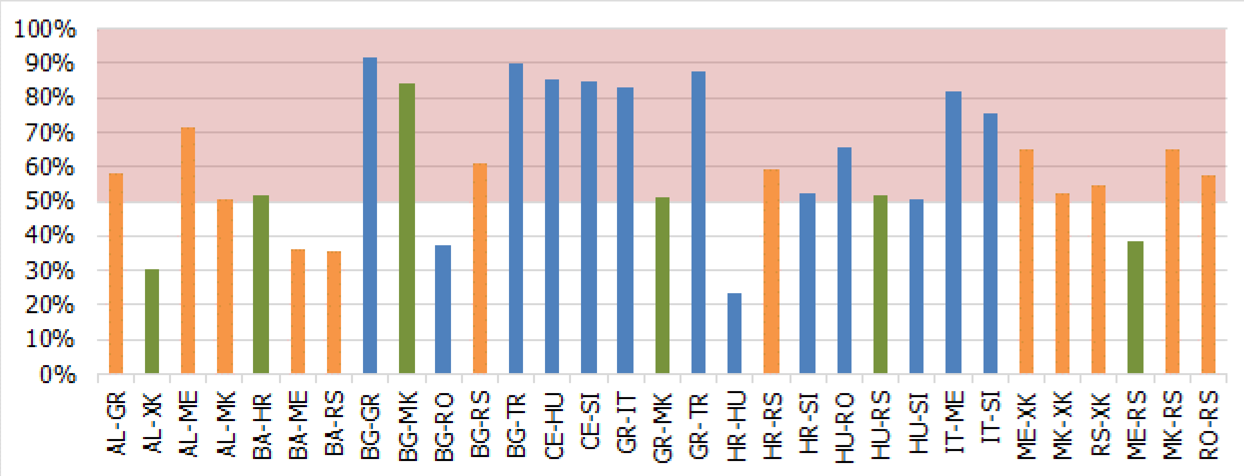


Figure 28: Cross-border loadings in both directions in 2025 (Baseline scenario – PMC)

Figure 28 shows that cross-border loadings in both directions range from 23% to 92%, depending on the border. In the PMC scenario, the borders with the highest loading are coupled, MK-BG and GR-MK. When analyzing borders not coupled in the PMC scenario, we can notice high loadings in both directions (i.e., above 50%) on all borders except BA-ME and BA-RS. Comparison with results from the SM scenario shows that loadings at all borders coupled in the PMC scenario become lower except at BG-MK. Even higher exchanges between market areas provoke lower loadings in this case (case with higher NTCs in comparison to SM scenario).

Cross-border congestion probability for each border is presented in Table 27. In 2025, there would be significant congestion probabilities (red colored cells), especially on the BG-GR, BG-TR, BG-MK and GR-TR borders, but only from the BG and to the TR market area. The other non-coupled borders with high congestion probability is the RS-HR border (towards the HOPS market area).

In general, stronger market integration and higher available cross-border capacities in the PMC scenario would reduce congestion compared to the SM scenario. This speaks in favor of greater market integration.

Table 27: Cross-border congestion probability in 2025 (Baseline scenario – PMC)

Market area	Congestion probability (%)														
	AL	**BA**	**BG**	**GR**	**HR**	**HU**	**ME**	**MK**	**RO**	**RS**	**SI**	**XK**	**CE**	**IT**	**TR**
AL	-			45			35	27				1			
BA		-			28		13			5					
BG			-	82				70	6	46					73
GR	10		0	-				0						39	65
HR		0			-	1				1	6				
HU					3	-			2	3	4		26		
ME	30	11					-			5		23		42	
MK	14		0	27				-		18		17			
RO			10			54			-	45					
RS		21	12		54	39	25	45	3	-		31			
SI					27	19					-		25	35	
XK	0						35	30		19		-	0		
CE						57					55		-		
IT				42			36				28			-	
TR			16	21											-

4.1.3 Full market coupling (FMC)

Electricity generation and consumption in SEE in the baseline Scenario and FMC in 2025 amounts to 285.86 TWh and 273.73 TWh, respectively. As in others coupling scenarios, the highest generation is in the TransElectrica market area (69.4 TWh), while the CGES market area has the lowest electricity generation (4.15 TWh).

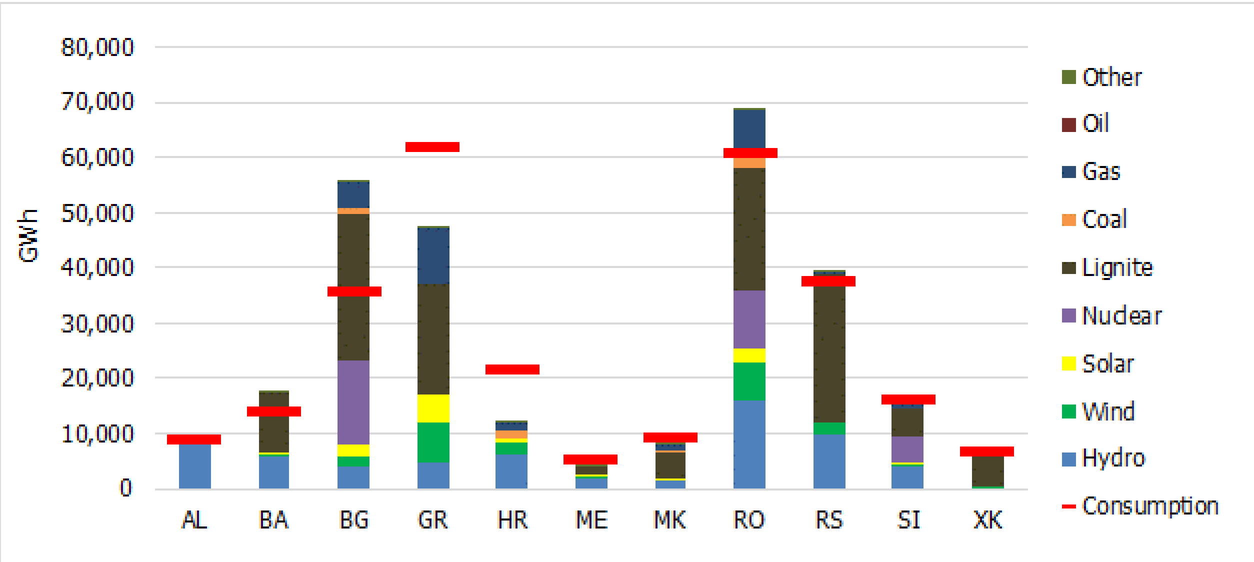


Figure 29: Electricity generation mix and consumption by market area in 2025 (Baseline scenario – FMC)

We present the expected 2025 generation mix by market area in more detail in the following table.

Table 28: Electricity generation mix by market area in 2025 (Baseline scenario – FMC)

Yearly generation (TWh)	AL	BA	BG	GR	HR	ME	MK	RO	RS	SI	XK	SEE
HPP	8.40	5.86	4.46	5.15	6.39	1.93	1.47	15.89	10.04	4.78	0.17	**64.53**
TPP lignite	0.00	11.07	26.40	19.96	0.00	1.51	4.68	22.35	26.95	5.17	6.59	**124.70**
TPP coal	0.00	0.00	1.32	0.00	1.74	0.00	0.61	3.44	0.00	0.00	0.00	**7.11**
TPP gas	0.00	0.00	4.74	10.14	1.21	0.00	0.80	6.76	0.43	0.41	0.00	**24.50**
TPP oil	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	**0.01**
TPP other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.96	0.00	0.00	0.00	**0.96**
Nuclear	0.00	0.00	15.43	0.00	0.00	0.00	0.00	10.44	0.00	4.90	0.00	**30.77**
Solar	0.07	0.07	1.88	5.33	0.56	0.41	0.09	2.52	0.01	0.39	0.08	**11.42**
Wind	0.15	0.62	1.77	7.01	2.27	0.30	0.18	7.06	2.17	0.04	0.30	**21.86**
TOTAL	**8.61**	**17.62**	**56.01**	**47.60**	**12.17**	**4.15**	**7.85**	**69.42**	**39.61**	**15.69**	**7.14**	**285.86**

As usual, TPPs have the highest share in the EMI region, except in the OST, HOPS and CGES market areas, where HPPs have the highest share. In addition, the TransElectrica, ELES and ESO EAD markets have notable shares of nuclear generation. The least diversified generation mix is again in the KOSTT area, with over 90% of generation from TPPs. Regarding wind and solar generation; GR and RO are again the leading countries, with 12.3 TWh and 9.5 TWh.

Electricity balances (i.e., yearly consumption, generation, exchange and transit values) for each SEE market area in the FMC scenario are given in Table 29. The ESO EAD and TransElectrica areas have the highest net interchange value (they are the region's main net exporters, while the ADMIE/IPTO and HOPS areas are significant net importers, similar to the SM and PMC scenarios. Annually, the OST and ELES market area are almost balanced. The total net interchange in SEE is not zero since we include neighboring power systems in this analysis.

Table 29: Electricity balance in 2025 (Baseline scenario – FMC)

Electricity balance	Cons. (GWh)	Gener. (GWh)	Pump load (GWh)	Custom. load (GWh)	Imports (GWh)	Exports (GWh)	Transit (GWh)	Net inter-change (GWh)	Net import / export share (%)
AL	8430	8612	0	8430	1820	2002	895	182	2.2%
BA	13483	17623	198	13285	252	4392	1542	4139	30.7%
BG	35439	56006	377	35062	0	20567	2607	20567	58.0%
GR	61552	47602	311	61248	13997	47	4330	-13949	-22.7%
HR	21372	12167	318	21054	9240	35	3488	-9205	-43.1%
ME	4774	4148	0	4774	1309	683	3846	-626	-13.1%
MK	8890	7845	0	8890	1294	249	4470	-1045	-11.8%
RO	60571	69423	0	60571	101	8953	2209	8852	14.6%
RS	37238	39607	334	36904	667	3036	6027	2369	6.4%
SI	15637	15693	785	14852	960	1016	13920	56	0.4%
XK	6340	7138	0	6340	395	1193	1022	798	12.6%
SEE	273726	285864	2324	271410	30035	42173		12138	4.4%

We calculate consumption in Table 29 by adding the customer load (demand) and pumped load for HPPs, and subtracting the energy not supplied (ENS, if it exists). Customer load is a predefined hourly input time series of demand, while the pumped load changes in scenarios, based on the operation of the pumped storage HPPs.

Generation in this table is the sum of the generation from all modelled power plants, without adding the curtailed generation (if it exists).

The projected 2025 yearly values for exports, imports, transits and net interchange for the SEE market areas were in Table 29, and here are presented for the neighboring power systems as well. Exports and imports values are depicted in Figure 30, transits in Figure 31 and net interchange in Figure 32 (exports are positive values, while imports are negative). In SEE, the ADMIE/IPTO and HOPS market areas are the highest net importers, with negligible exports, while and ESO EAD and TransElectrica are the highest net exporters, with almost no imports.

It is clear from Figure 31 that the highest transit goes through ELES as in the SM and PMC scenarios. Regarding neighboring systems, the highest transits are through HU. Also, HU and TK mostly import electricity from SEE, CE mostly exports electricity to SEE, and Italy is balanced with SEE, as expected considering the level of wholesale market prices in neighboring markets (see chapter 2.5).

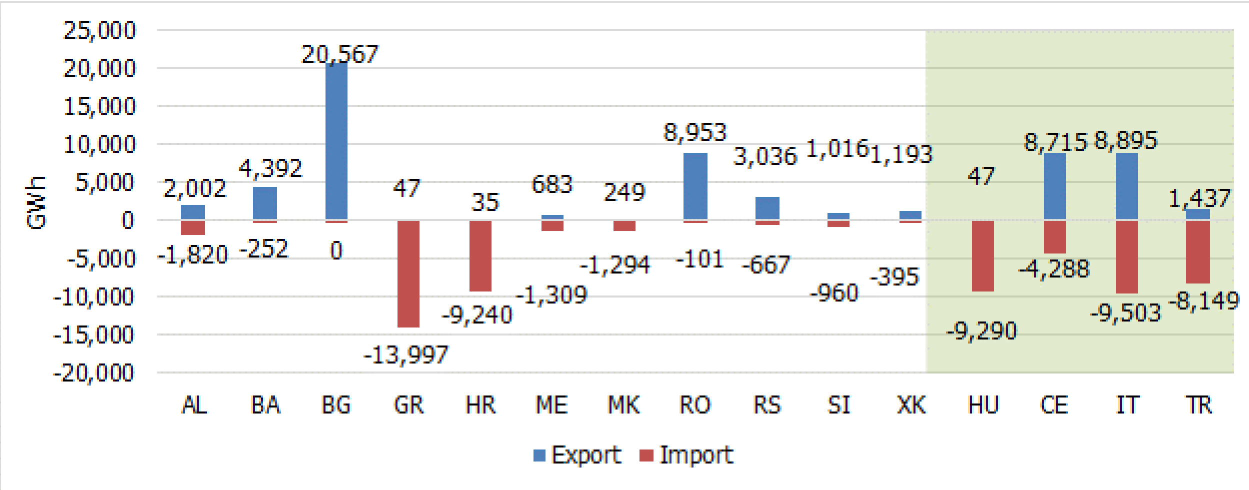


Figure 30: Imports and exports in 2025 (Baseline scenario – FMC)

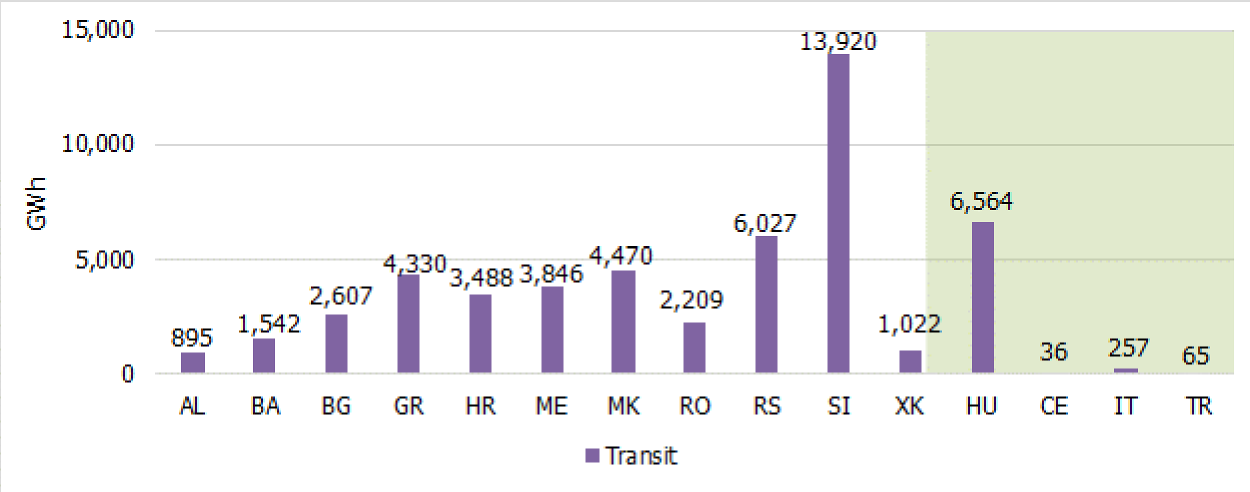


Figure 31: Transits in 2025 (Baseline scenario – FMC)

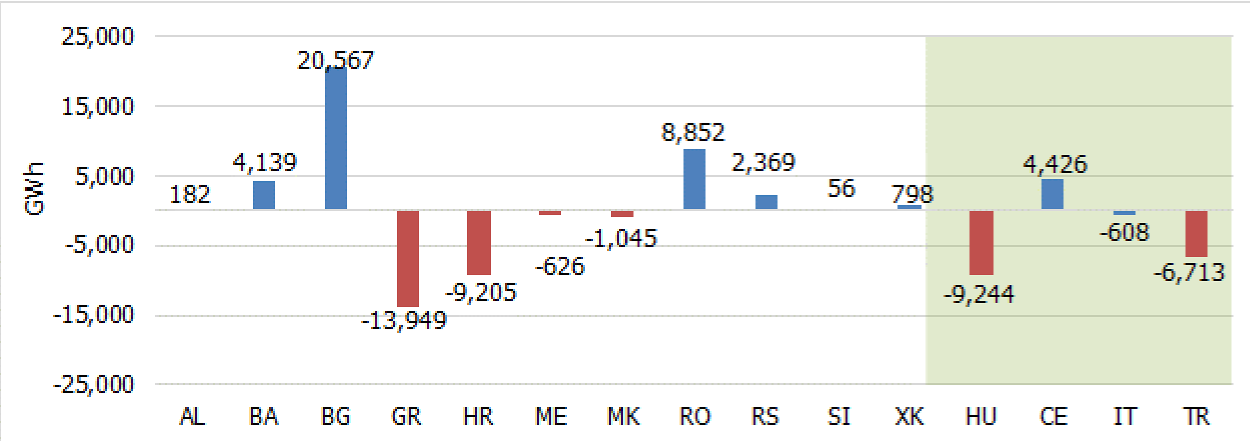


Figure 32: Net interchange in 2025 (Baseline scenario – FMC)

Operating costs are the most important factor in the differences among SEE market areas (see yearly simulation results in Table 30). As in all scenarios, we determine the market price from the marginal cost of generation and the price in neighboring markets. Operating costs include the variable costs of fuel, CO_2 and the O&M of generating units.

The 2025 expected average operating costs in the SEE region are 13.31 €/MWh, without considering $C0_2$ costs. The highest operating cost is in ADMIE/IPTO market area (16.71 €/MWh), followed by ESO EAD (16.26 €/MWh) where TPPs have a high share. Table 30 also presents yearly CO_2 emissions in SEE, and the costs of those emissions. The highest CO_2 emissions would be in the TransElectrica and EMS market areas. Average total operating costs, which include also carbon costs, amount to 26.17 €/MWh in SEE region. In terms of average total operating cost, KOSTT market area has the highest value (36.67 €/MWh) followed by MEPSO market area (34.19 €/MWh). This is due to carbon cost, which mostly affects market areas with high share of coal-based TPPs.

In this scenario, the average SEE regional wholesale market price in 2025 is 55.74 €/MWh. While wholesale prices become more harmonized in the region than in the PMC scenario, as expected, there are still variations. For example, the ADMIE/IPTO and HOPS market areas still have highest average wholesale prices (58.53 €/MWh and 58.02 €/MWh). There is a group of market areas below average (between 54 and 55 €/MWh), with ESO EAD as the lowest (54.348 €/MWh). The third group includes the OST, NOSBiH and ELES market areas, with prices above 55 €/MWh.

Table 30: Operating costs in 2025 (Baseline scenario– FMC)

Operating costs without and with emissions costs	AL	BA	BG	GR	HR	ME	MK	RO	RS	SI	XK	SEE
Operating costs (mil. €)	0	174	911	796	113	23	120	1,007	408	160	93	**3,805**
CO_2 emissions (mil. tonne)	0	14	27	23	2	1	6	29	28	5	7	**143**
CO_2 emissions costs (mil. €)	0	357	703	593	56	39	148	757	724	131	169	**3,676**
Total operating costs (mil. €)	0	531	1,614	1,388	169	62	268	1,764	1,133	291	262	**7,481**
Average operating costs (€/MWh)	0.00	9.90	16.26	16.71	9.27	5.58	15.36	14.51	10.31	10.20	12.97	**13.31**
Average total operating costs (€/MWh)	0.00	30.15	28.81	29.17	13.87	14.87	34.19	25.41	28.60	18.53	36.67	**26.17**
Price (€/MWh)	55.27	55.04	54.34	58.53	58.02	54.77	54.37	54.38	54.41	55.67	54.62	**55.74**

Yearly cross-border exchange, loading and congestions results are analyzed in the following.

As in other scenarios, ELES has the highest cross-border exchange (Table 31) (i.e., 28,817 GWh, with 14,936 GWh from ELES' market area to its neighbors, and 14,880 GWh in the opposite direction). The KOSTT area has the lowest cross-border exchanges (3,632 GWh, with 2,215 GWh into neighboring areas, and 1,412 GWh in the opposite direction). The highest yearly flows are on the BG-GR border, from ESO EAD's to ADMIE/IPTO's market area, as in the SM and PMC scenarios.

Table 31: Cross-border exchange in 2025 (Baseline scenario – FMC)

Market area	Flow (GWh)														
	AL	BA	BG	GR	HR	HU	ME	MK	RO	RS	SI	XK	CE	IT	TR
AL	-			1,101			948	575				273			
BA		-			4,854		876			204					
BG			-	10,590				3,237	1,902	1,618					5,827
GR	116		0	-				81						1,794	2,388
HR		116			-	681				48	2,679				
HU					1,602	-			342	465	2,152		2,050		
ME	1,229	482					-			109		341		2,367	
MK	484		1	3,993				-		127		114			
RO			1,591			5,618			-	3,953					
RS		1,197	290		2,480	2,292	840	1,210	66	-		689			
SI					3,792	3,270					-		2,275	5,599	
XK	887						496	661		171		-			
CE						3,993					4,758		-		
IT				1,866			1,994				5,292			-	
TR			725	777											-

Yearly average cross-border loadings in Table 32 give us better insight into the interconnections at each border. The cells in red show high flows (i.e., loadings above 50%), while those in green show low flows (i.e., loadings below 10%). In this scenario, the highest cross-border loadings also occur on BG-GR border (90%, towards the ADMIE/IPTO area), consistent with the high flows on that border shown in the previous table. High loadings also occur on the BG-TR and BG-MK borders (74%, direction to TR and MK). Generally, almost all links to ADMIE/IPTO and TR are highly loaded, as in the SM and PMC scenarios. TransElectrica market area's cross-border lines have notably low loadings towards TransElectrica (range 1-13%), and significantly higher in the opposite direction (range 20-66%), which confirms TransElectrica as a significant electricity exporter in the full market coupling scenario as well. This is the same for ESO EAD, while for HR and HU it is the opposite, since they are significant importers. This table confirms that the main directions of electricity flow remain the same as in the SM and PMC cases.

Table 32: Cross-border loading in 2025 (Baseline scenario – FMC)

Market area	Loading (%)														
	AL	BA	BG	GR	HR	HU	ME	MK	RO	RS	SI	XK	CE	IT	TR
AL	-			50			22	16				5			
BA		-			49		17			4					
BG			-	90				74	18	46					74
GR	5		0	-				1						41	68
HR		1			-	8				1	25				
HU					15	-			4	9	21		29		
ME	28	9					-			4		13		45	
MK	9		0	55				-		7		7			
RO			17			58			-	45					
RS		23	8		57	44	32	43	1	-		26			
SI					33	31					-		27	40	
XK	16						19	23		5		-	0		
CE						57					57		-		
IT				43			38				37			-	
TR			17	21											-

The next figure shows cross-border loadings in both directions (i.e. the sum of loadings in reference and counter-reference directions). The blue bars are borders coupled in all scenarios, while the green bars are borders coupled in the FMC scenario. In this scenario, there are no non-coupled borders.

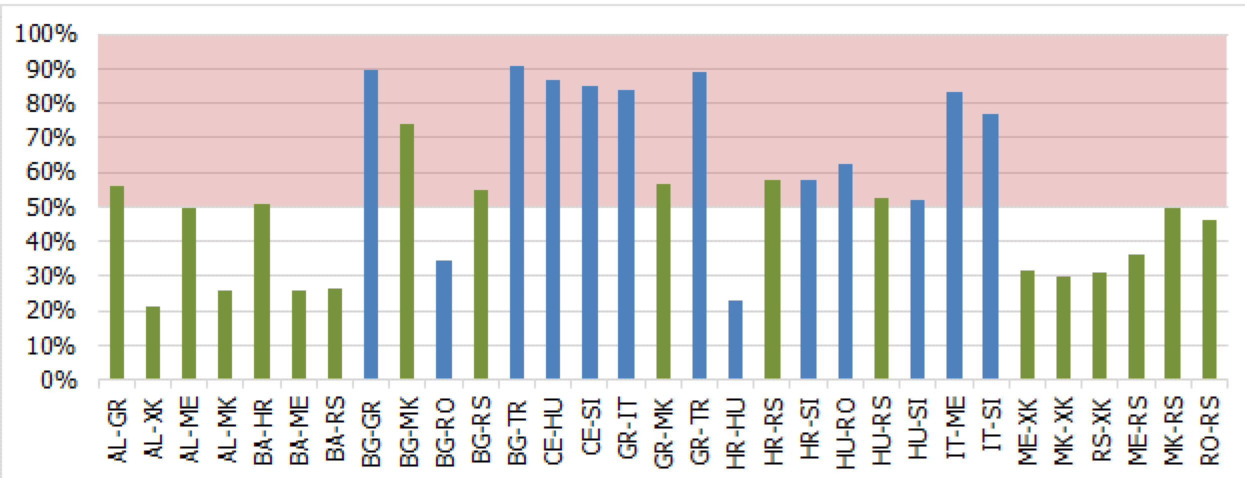


Figure 33: Cross-border loadings in both directions in 2025 (Baseline scenario – FMC)

Figure 33 shows that cross-border loadings range from 24% to 92% depending on the border. We continue to note high loadings in both directions (i.e. loadings above 50%) on AL-GR, AL-MK, BA-HR, BG-MK, BG-RS, GR-MK, HR-RS, HU-RS and MK-RS borders, but significantly lower than in the case of SM scenario. In general, the FMC scenario produces higher NTC utilization and thus higher exchanges between market areas, leading to lower loadings and less congestion compared to the SM and PMC scenarios.

Cross-border congestions represent the number of hours in a year with flows on interconnections that is equal to the modelled NTC. We present the cross-border congestion probability for each border in Table 85. Cells in red have high congestion probability (i.e., above 50%), while those in green have low probability (i.e., below 10%). There are significant congestion probabilities on the BG-GR, BG-TR and GR-TR borders, but only in one direction – towards the Turkish and ADMIE/IPTO markets. On borders coupled in this FMC scenario that were not coupled in the SM scenario, we note a decrease in congestion probability, since the markets can use a greater share of their NTCs.

Table 33: Cross-border congestion probability in 2025 (Baseline scenario – FMC)

Market area	Congestion probability (%)														
	AL	BA	BG	GR	HR	HU	ME	MK	RO	RS	SI	XK	CE	IT	TR
AL	-			47			12	10				0			
BA		-			34		5			1					
BG			-	79				58	8	42					72
GR	5		0	-				0						41	68
HR		0			-	1				1	10				
HU					1	-			1	5	4		28		
ME	17	3					-			3		8		45	
MK	2		0	36				-		7		5			
RO			7			50			-	28					
RS		10	6		51	40	25	36	0	-		19			
SI					29	20					-		26	37	
XK	1						10	13		2		-	0		
CE						57					54		-		
IT				42			37				28			-	
TR			17	21											-

4.1.4 Comparison of different market coupling scenarios

Table 34 compares total power generation in SEE for the baseline and market coupling scenarios in both absolute (TWh) and relative (%) terms, compared to the separated market (SM) scenario.

Total regional generation increases in the PMC scenario by 2.19 TWh (0.77%) and in the FMC scenario by 2.71 TWh (0.96%) compared to the SM scenario. This is due to the opportunity for higher electricity exports with market coupling. In different MC scenarios, the highest generation is in TransElectrica, and the lowest in CGES's area, but it is important to observe the effect of market coupling. By comparing the results in Table 34 and Table 38, we see that the most significant increase with market coupling occurs in export areas (such as NOSBiH, ESO EAD and TransElectrica), while decreased generation occurs in importing areas (such as HOPS and ADMIE/IPTO). That is, more extensive coupling leads to higher increases/decreases of generation in individual markets. This is largely because market coupling gives better NTC utilization, thus unlocking opportunities for more exports and imports, in the form of more generation from exporters and less by importers. In a couple market areas, there is no significant change (e.g., in the OST and CGES areas) due to a high share of hydro generation which does not change across these MC scenarios.

Table 34: Comparison of electricity generation by market area in 2025 (Baseline scenario)

Yearly generation (TWh)	AL	BA	BG	GR	HR	ME	MK	RO	RS	SI	XK	SEE
Separated markets	8.61	17.19	54.40	48.93	12.30	4.15	7.79	67.77	39.21	15.79	7.02	**283.15**
Partial market coupling	8.61	17.94	55.33	48.14	12.21	4.15	7.92	68.55	39.70	15.72	7.09	**285.34**
Change (TWh)	0.00	0.75	0.93	-0.79	-0.09	0.00	0.13	0.77	0.49	-0.07	0.07	**2.19**
Change (%)	0.00	4.38	1.71	-1.62	-0.72	-0.01	1.66	1.14	1.24	-0.46	0.95	**0.77**
Full market coupling	8.61	17.62	56.01	47.60	12.17	4.15	7.85	69.42	39.61	15.69	7.14	**285.86**
Change (TWh)	0.00	0.43	1.61	-1.33	-0.13	0.00	0.06	1.65	0.40	-0.10	0.12	**2.71**
Change (%)	0.00	2.51	2.96	-2.72	-1.05	0.01	0.75	2.44	1.02	-0.63	1.68	**0.96**

Table 35 compares annual exports; import values are in Table 36; and transit values are in Table 37. We should analyze these tables together, along with Figure 42. In all Baseline scenarios, the ADMIE/IPTO and HOPS market area are the highest electricity importers and ESO EAD, TransElectrica and NOSBiH area are the highest exporters, while the greatest transit is through ELES.

In total, in the SEE region, in the Baseline Scenario, electricity exports would increase in 2025 by 2,743 GWh (7.28%) in PMC scenario and by 4,518 GWh (12%) in FMC. Imports would increase by 766 GWh (2.7%) in the PMC scenario and by 1,713 GWh (6.05%) in FMC. Overall, as the electricity market becomes more integrated, there will be significant changes in exports and imports, both for the region, and to a even greater extent, for individual electricity markets.

By considering the export and import tables, we also conclude the following:

- First, on a regional level, export increase more than imports, showing that there is greater net exchange with PMC and FMC compared with SM. The whole region exports with more coupling, as transmission utilization rises to support higher export of "cheaper" electricity to neighboring power systems, such as HU, TR, and IT.
- Second, for individual countries under the coupling scenarios, almost all market areas grow their exports, while a few increase imports, as larger exporters and importers generally grow their exports/imports the most. Again, this is because coupling allows better use of NTCs, while unlocking generation in exporting areas to replace expensive generation elsewhere.

In addition, from Table 37 it is clear that in both the PMC and FMC cases, transits are notably changed compared with the SM situation (rising over 30% from SM to FMC). We conclude that market integration would meaningfully boost energy exchanges and flows across the SEE region.

To summarize, coupling in the SEE region will boost net exports, especially by countries already exporting, and will raise the net exports of the region as whole. One share of those extra exports is redistributed between the SEE countries (some countries increase net imports), while the other share is exported outside SEE to areas such as HU, TR, and to a lesser extent, IT.

Table 35: Comparison of export by market area in 2025 (Baseline)

Export (GWh)	AL	BA	BG	GR	HR	ME	MK	RO	RS	SI	XK	SEE
Separated markets	1,654	4,032	19,002	14	109	611	129	7,326	2,632	1,045	1,101	**37,655**
Partial market coupling	1,792	4,556	19,896	19	53	704	217	8,085	2,905	1,022	1,149	**40,398**
Change (GWh)	138	524	894	5	-56	93	88	759	273	-23	48	**2,743**
Change (%)	8.34	13.00	4.70	35.71	-51.38	15.22	68.22	10.36	10.37	-2.20	4.36	**7.28**
Full market coupling	2,002	4,392	20,567	47	35	683	249	8,953	3,036	1,016	1,193	**42,173**
Change (GWh)	348	360	1,565	33	-74	72	120	1,627	404	-29	92	**4,518**
Change (%)	21.04	8.93	8.24	235.71	-67.89	11.78	93.02	22.21	15.35	-2.78	8.36	**12**

Table 36: Comparison of import by market area in 2025 (Baseline)

Import (GWh)	AL	BA	BG	GR	HR	ME	MK	RO	RS	SI	XK	SEE
Separated markets	1,472	289	0	12,627	9,247	1,237	1,231	127	678	994	420	**28,322**
Partial market coupling	1,610	202	0	13,416	9,239	1,331	1,190	110	614	974	402	**29,088**
Change (GWh)	138	-87	0	789	-8	94	-41	-17	-64	-20	-18	**766**
Change (%)	9.38	-30.10	0.00	6.25	-0.09	7.60	-3.33	-13.39	-9.44	-2.01	-4.29	**2.7**
Full market coupling	1,820	252	0	13,997	9,240	1,309	1,294	101	667	960	395	**30,035**
Change (GWh)	348	-37	0	1,370	-7	72	63	-26	-11	-34	-25	**1,713**
Change (%)	23.64	-12.80	0.00	10.85	-0.08	5.82	5.12	-20.47	-1.62	-3.42	-5.95	**6.05**

Figure 34 compares yearly exports and imports for our different market coupling scenarios.

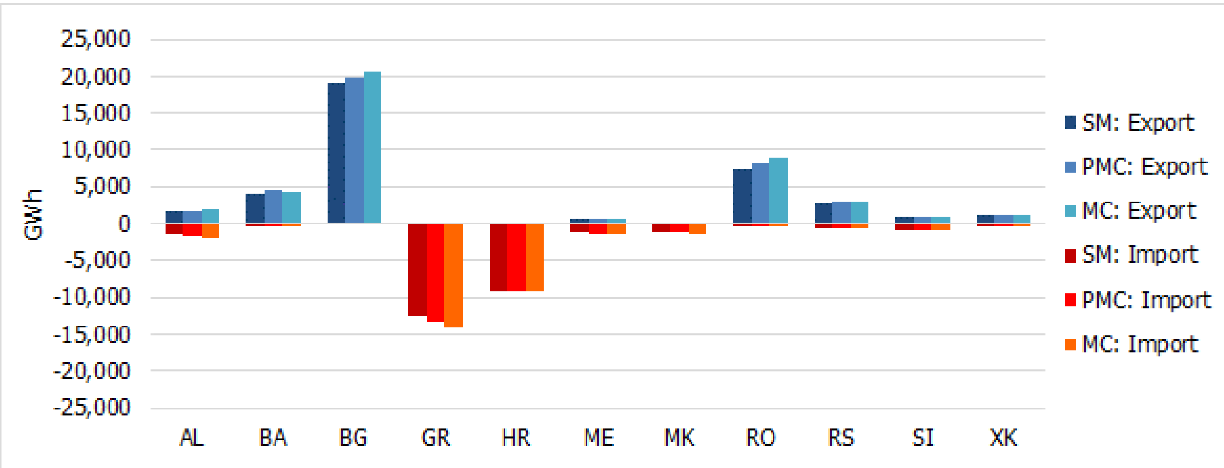


Figure 34: Comparison of exports and imports in 2025 (Baseline)

Table 37: Comparison of transits by market area in 2025 (Baseline scenario)

Transit (GWh)	AL	BA	BG	GR	HR	ME	MK	RO	RS	SI	XK	SEE
Separated markets	638	672	2,489	3,998	1,395	3,263	2,528	2,414	2,965	12,786	870	**34,018**
Partial market coupling	774	1,090	2,970	4,210	2,640	3,307	4,253	2,141	3,808	13,447	1,226	**39,866**
Change (GWh)	136	418	481	212	1,245	44	1,725	-273	843	661	356	**5,848**
Change (%)	21.32	62.20	19.33	5.30	89.25	1.35	68.24	-11.31	28.43	5.17	40.92	**17.19**
Full market coupling	895	1,542	2,607	4,330	3,488	3,846	4,470	2,209	6,027	13,920	1,022	**44,356**
Change (GWh)	257	870	118	332	2,093	583	1,942	-205	3,062	1,134	152	**10,338**
Change (%)	40.28	129.46	4.74	8.30	150.04	17.87	76.82	-8.49	103.27	8.87	17.47	**30.39**

In order to adequately assess the net interchange increase and redistribution across the region, we analyzed data from Table 38. By summing up the change in imports (negative net interchanges), we conclude that market coupling would increase imports by 835 GWh in the PMC scenario, and by 1399 GWh in FMC, in comparison to SM. At the same time, market coupling unlocks additional generation in the exporting areas, and enables changes in exports by 2813 GWh in the PMC scenario, and by 4205 GWh in FMC. This provides additional energy both for the SEE region, and also increases exports outside the region (exports jump from 1977 GWh to 2807 GWh). Clearly, as the market becomes more integrated, interchanges (exports and imports) increase substantially.

Table 38: Comparison of net interchange by market area in 2025 (Baseline)

Net interchange (GWh)	AL	BA	BG	GR	HR	ME	MK	RO	RS	SI	XK	SEE
Separated markets	182	3,743	19,002	-12,614	-9,138	-626	-1,103	7,200	1,954	51	681	**9,332**
Partial market coupling	182	4,353	19,896	-13,397	-9,186	-627	-973	7,974	2,291	48	747	**11,309**
Change (GWh)	0	611	895	-784	-48	0	130	775	336	-3	66	**1,977**
Full market coupling	182	4,139	20,567	-13,949	-9,205	-626	-1,045	8,852	2,369	56	798	**12,138**
Change (GWh)	0	396	1,566	-1,336	-67	0	58	1,653	415	4	117	**2,807**

SEE's exchanges with Hungary, Italy, Turkey and Central Europe is depicted in the following figures for SM, PMC and FMC scenarios (Figure 35 to Figure 37). The values in arrows show the direction of exchange – blue arrows show exports from the SEE region to specific neighboring market areas, and red arrows show imports to the SEE region from neighboring market areas.

The neighboring market areas import 28,740 GWh from SEE in the SM scenario, 30,409 GWh in the PMC scenario, and 31,230 GWh in the FMC scenario. At the same time, they export to SEE region 19,407 GWh of electricity in the SM scenario, 19,091 GWh in the PMC scenario and 19,094 GWh in the FMC scenario. We conclude that SEE market integration will boost regional exports, while keeping imports on almost the same level, which is in line with previous conclusions.

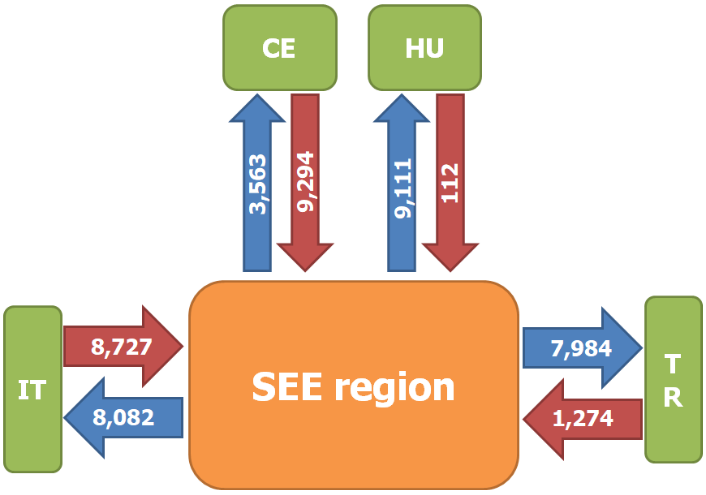


Figure 35: Hungary, Italy, Turkey, Central Europe and SEE region exchange in 2025 (Baseline – SM)

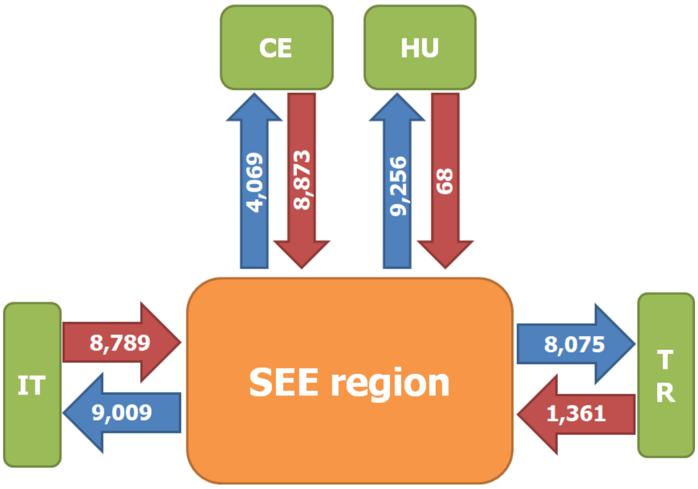


Figure 36: Hungary, Italy, Turkey, Central Europe and SEE region exchange in 2025 (Baseline – PMC)

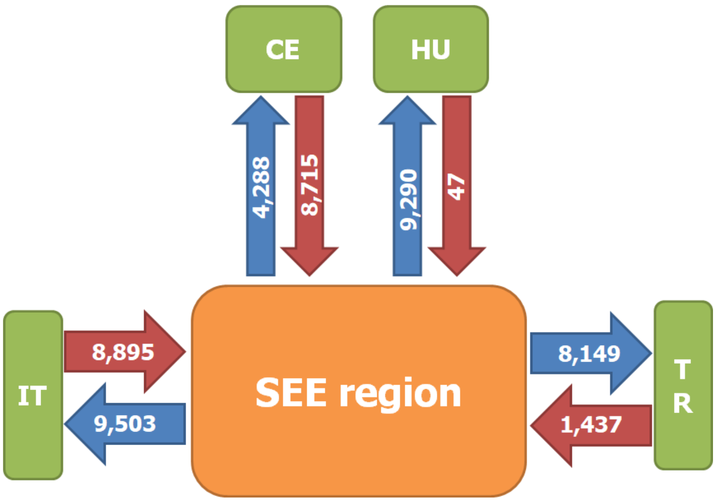


Figure 37: Hungary, Italy, Turkey, Central Europe and SEE region exchange in 2025 (Baseline - FMC)

We compare yearly net interchange values for different market coupling scenarios in Figure 38. In this comparison, we see that market integration leads to fewer imports from CE, and greater exports to HU. Again, we conclude that market integration unlocks the potential for additional generation and exchange of "cheaper" electricity. It also decreases imports from neighboring regions (such as CE) and increases exports to other neighboring regions (such as Hungary and Italy).

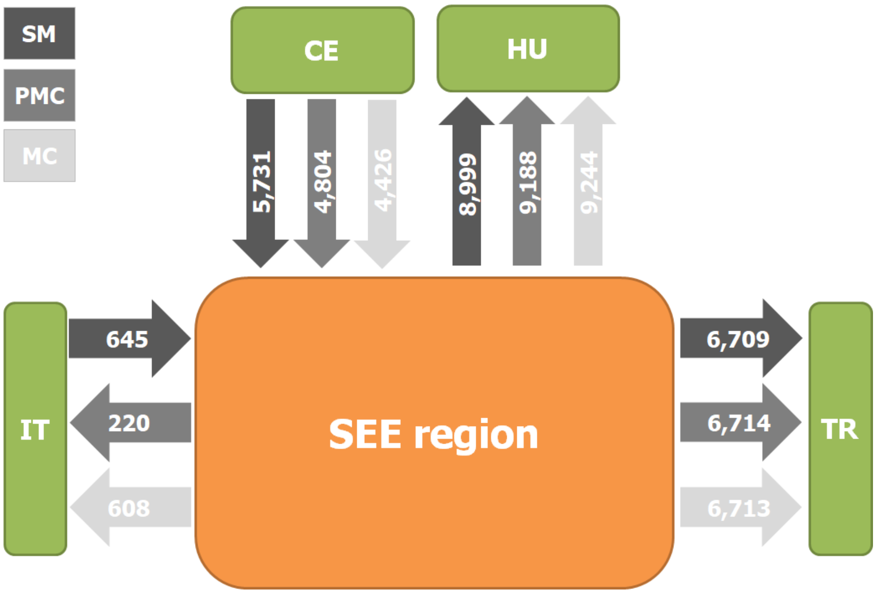


Figure 38: Hungary, Italy, Turkey, Central Europe and SEE region net interchange in 2025 (Baseline – comparison of the coupling scenarios)

In our market model, the wholesale market price is determined by the marginal cost of generation. We present the resulting wholesale prices by market area in Table 39. We calculate average wholesale market prices in the SEE region as the load-weighted average value for all market areas in the region. Using this approach, the average market price in the SEE region amounts to 56.12 €/MWh in the SM scenario, 55.83 €/MWh in the PMC case of partial market coupling and 55.74 €/MWh in the FMC scenario. Thus, the average SEE market price in the PMC scenario is 0.28 €/MWh (0.51%) lower than in the SM scenario, and in the FMC scenario it is 0.37 €/MWh (0.67%) lower. Overall, SEE market integration promotes lower prices.

In most exporting countries of the SEE market areas, average market prices increase with greater market integration, while in the importing market areas, wholesale prices fall. We expected this results, as market coupling enables higher exchanges of "cheaper" energy, moving prices close to each other. If there were no cross-border constraints, prices would be equal across borders.

Table 39, together with changes in net interchange (Table 38), shows us the interdependence between an increase in exports/imports and an increase/decrease in prices. This is a logical consequence of market integration, since market coupling provide exporting countries (countries with lower prices) opportunities to export more electricity to importing countries (those with higher prices). This leads to a price convergence across SEE, as lower-price areas increase, and higher-price areas decrease in price.

For example, ADMIE/IPTO, a large importer, shows a substantial wholesale price decrease, by 3.94 €/MWh in the PMC scenario and 5.25 €/MWh in the FMC scenario, compared to the SM scenario. The ADMIE/IPTO market area can thus expect larger benefits from market coupling in the SEE region than any other market area.

On the other hand, the ESO EAD market area would have a price increase of 0.92 €/MWh in the PMC scenario, and 1.92 €/MWh in FMC, compared with SM. Thus, the price difference between the ADMIE/IPTO and the ESO EAD market areas falls from 11.37 €/MWh to 6.5 €/MWh and 4.19 €/MWh through different levels of market coupling. In addition, this may reduce the congestion rents that TSOs can collect on the border between these market areas.

As a result of market integration, Table 39's final column shows this decrease in price differentials using the price coefficient of variation (CV). The CV is expressed as a percentage, calculated as the ratio of the standard deviation to the mean (average) of the prices in the EMI market areas. As market integration increases, the CV falls, showing that wholesale prices are less dispersed.

At the SEE regional level, average prices also decrease with stronger coupling of the market areas (the SEE column in Table 39). While counter-intuitive, this is because the region is exporting more as coupling grows. Average regional prices are calculated as load-weighted average values. Since there is a significant price decrease (4 or 5 €/MWh) in a large market area (ADMIE/IPTO) and, at the same time, a small price increase (of 1 or 2 €/MWh) in another large area (TransElectrica), the average regional values show a decrease as market coupling gets stronger.

Table 39: Comparison of average wholesale prices by market area in 2025 (Baseline)

Price (€/MWh)	AL	BA	BG	GR	HR	ME	MK	RO	RS	SI	XK	SEE	CV
Separated markets	55.51	54.15	52.42	63.79	58.23	54.21	54.61	52.40	53.28	56.53	54.89	**56.12**	**5.59%**
Partial market coupling	56.05	55.62	53.34	59.84	57.73	55.29	56.08	53.23	54.81	55.94	55.34	**55.83**	**3.17%**
Change (€/MWh)	0.54	1.47	0.92	-3.94	-0.49	1.09	1.47	0.83	1.52	-0.59	0.45	**-0.28**	
Change (%)	0.97	2.72	1.75	-6.18	-0.85	2.00	2.70	1.59	2.86	-1.04	0.82	**-0.51**	
Full market coupling	55.27	55.04	54.34	58.53	58.02	54.77	54.37	54.38	54.41	55.67	54.62	**55.74**	**2.56%**
Change (€/MWh)	-0.24	0.89	1.92	-5.25	-0.21	0.56	-0.24	1.99	1.13	-0.86	-0.26	**-0.37**	
Change (%)	-0.44	1.64	3.66	-8.24	-0.36	1.04	-0.44	3.79	2.11	-1.53	-0.48	**-0.67**	

We compare average wholesale prices by market area in the different scenarios in Figure 82.

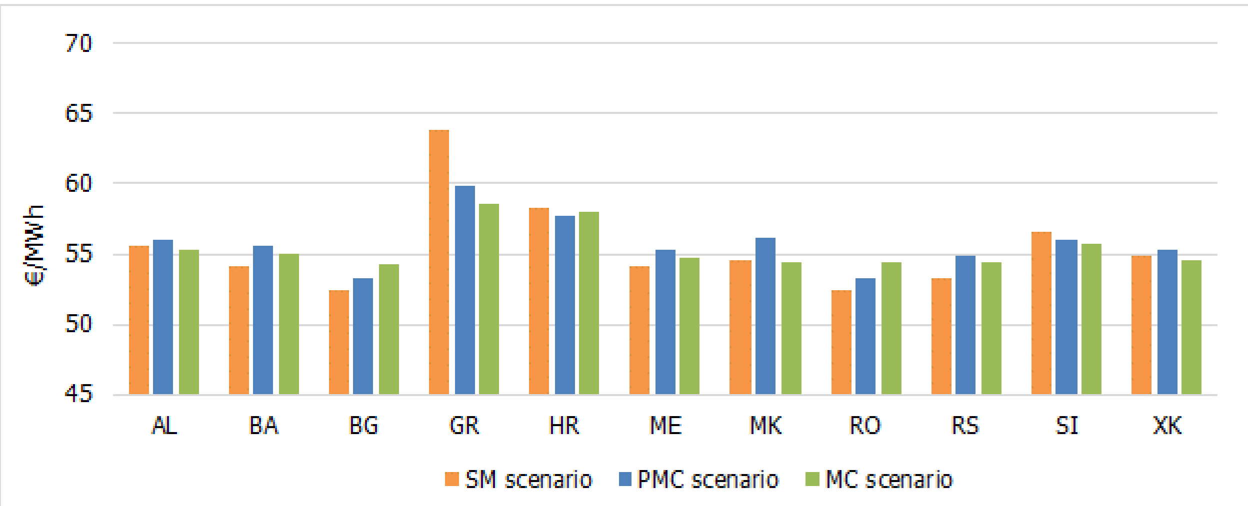


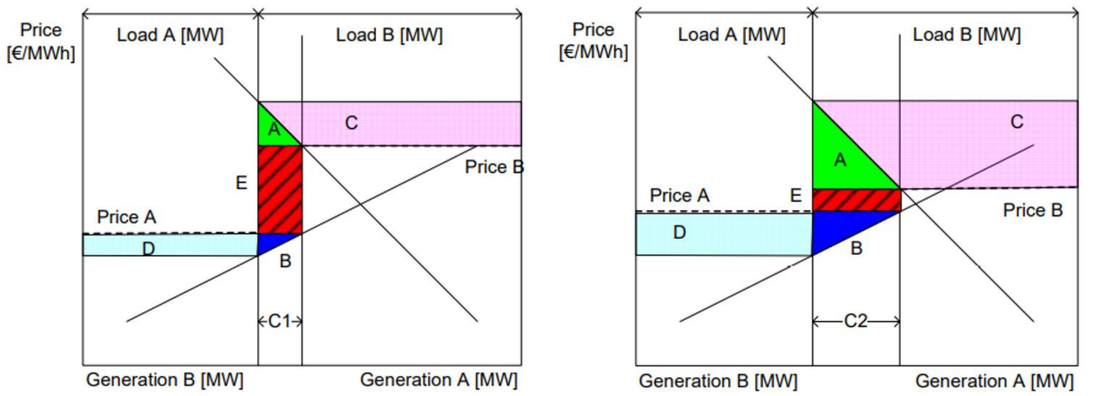
Figure 39: Comparison of average wholesale prices in 2025 (Baseline)

After analyzing different market parameters, we calculate the change in social-economic welfare (SEW) to fully evaluate the overall impact of regional market integration in the SEE region.

4.1.5 Calculation of social-economic welfare (SEW)

According to ENTSO-E, SEW is defined as the change in total surplus (sum of consumer surplus, producer surplus and congestion rents) in the PMC and MC scenarios, compared to the SM scenario, as shown in Figure 40:

- With greater coupling, the generation fleet is more efficiently and economically engaged, and this is reflected in the sum of the producer surpluses.
- Greater coupling also enables more energy exchanges between lower-price and higher price areas, which is followed by price harmonization (reduction of price differentials), and changes in the consumer surpluses.
- Finally, market coupling leads to a change in congestion rent for the TSOs (usually negative).



A: An absolute increase in consumer surplus due to increased transmission capacity
B: An absolute increase in producer surplus due to increased transmission capacity
C: A transfer from producer surplus to consumer surplus
D: A transfer from consumer surplus to producer surplus
E: Congestion rent

Figure 40: Impact of the market coupling on change of market surplus (source: ENTSO-E)

The SEW benefit is quantified on hourly basis, based on the market simulation results, as the difference between the calculated total surplus in different MC scenarios.

The following table presents SEW by market area under the different market integration options for the baseline scenario.

Table 40: Comparison of socio-economic welfare in 2025 (Baseline)

Market area	Partial market coupling - Separated markets				Full market coupling - Separated markets			
million €	Δ Producer surplus	Δ Consumer surplus	Δ Congestion rent	Δ Total surplus	Δ Producer surplus	Δ Consumer surplus	Δ Congestion rent	Δ Total surplus
AL	8.02	-4.52	-1.41	**2.08**	6.01	2.04	-4.37	**3.68**
BA	30.06	-19.58	-3.24	**7.24**	17.08	-11.82	-0.08	**5.18**
BG	48.50	-32.13	-22.40	**-6.03**	102.05	-67.24	-44.08	**-9.28**
GR	-182.28	244.03	-44.69	**17.05**	-238.53	324.82	-56.46	**29.83**
HR	-10.56	10.41	-5.27	**-5.42**	-10.44	4.36	4.59	**-1.49**
ME	7.88	-5.18	-3.06	**-0.37**	3.50	-2.69	-3.52	**-2.71**
MK	12.01	-13.09	-0.19	**-1.27**	0.55	2.14	-7.87	**-5.18**
RO	56.84	-50.40	-4.42	**2.03**	137.20	-120.37	-12.36	**4.48**
RS	60.13	-56.21	-1.38	**2.54**	46.89	-41.57	-5.10	**0.22**
SI	-8.48	8.71	5.63	**5.86**	-12.48	12.83	14.09	**14.44**
XK	4.86	-2.84	0.50	**2.53**	-0.10	1.71	-3.76	**-2.14**
TOTAL SEE	**26.97**	**79.19**	**-79.94**	**26.23**	**51.72**	**104.22**	**-118.92**	**37.02**

For the SEE region, the benefits range from 26 million EUR in the PMC scenario to 37 million EUR under FMC. Consumer surplus and congestion rents just about offset each other, and the positive producer surplus makes the total surplus notable positive as well.

While some market areas have positive SEW and others are negative, market coupling is quite worthwhile overall.

As mentioned, the ADMIE/IPTO market area shows the greatest benefit due to current adequacy issues (and Energy Not Supplied) which stronger coupling will meaningfully reduce. Stronger coupling significantly reduces ADMIE/IPTO market price, producing a large increase in consumer surplus. Also, coupling reduces congestion on the borders with the ESO EAD market area, and so it reduces the price differential, leading to lower congestion rents for both TSOs.

In almost all the market areas, market coupling will decrease congestion rents, as expected since there is more cross-border capacity available for market transactions with increased market coupling. In some cases, like the ESO EAD, CGES and MEPSO market areas, a decrease in congestion rents does lead to a negative total surplus.

Only the market areas that are between two distinct price groups (like ELES, and partially KOSTT and HOPS) will benefit from increased congestion rents under market coupling. In all other market areas, price convergence and more cross-border capacity leads to lower TSO congestion rents.

On the other side, almost all market areas have benefits from market coupling when considering the sum of producer and consumer surpluses. In case of exporting areas, the benefits are more on the producers side, while in importing ones, on consumers side, due to higher/lower prices, respectively. We present the sum of the changes in producer and consumer surpluses in Table 41. In almost all market areas, this sum shows positive benefits from market coupling for producers and consumers.

Table 41: Comparison of the sum of changes in producer and consumer surpluses in 2025 (Baseline)

Market area	Partial market coupling - Separated markets			Full market coupling - Separated markets		
million €	Δ Producer surplus	Δ Consumer surplus	Sum	Δ Producer surplus	Δ Consumer surplus	Sum
AL	8.02	-4.52	**3.5**	6.01	2.04	**8.05**
BA	30.06	-19.58	**10.48**	17.08	-11.82	**5.26**
BG	48.50	-32.13	**16.37**	102.05	-67.24	**34.81**
GR	-182.28	244.03	**61.75**	-238.53	324.82	**86.29**
HR	-10.56	10.41	**-0.15**	-10.44	4.36	**-6.08**
ME	7.88	-5.18	**2.7**	3.5	-2.69	**0.81**
MK	12.01	-13.09	**-1.08**	0.55	2.14	**2.69**
RO	56.84	-50.40	**6.44**	137.2	-120.37	**16.83**
RS	60.13	-56.21	**3.92**	46.89	-41.57	**5.32**
SI	-8.48	8.71	**0.23**	-12.48	12.83	**0.35**
XK	4.86	-2.84	**2.02**	-0.1	1.71	**1.61**
TOTAL SEE	**26.97**	**79.19**	**106.16**	**51.72**	**104.22**	**155.94**

The vast majority of these sums are positive. However, in the HR (HOPS) market area, coupling with the BA (NOSBiH) market area reduces prices, but maintains high internal generation, so the increase in consumer surplus is more than offset by a decrease in producer surplus. As another example, in the MK (MEPSO) market area, under PMC, coupling with the ESO EAD and ADMIE/IPTO market areas will increase prices, which reduces consumer surplus and, since it is an importing area, it will increase the producer surplus, but not quite by as much as the decrease in consumer surplus.

In the FMC case, the further coupling of the HOPS and EMS market areas leads to a smaller increase in prices compared to the PMC case. This slightly increases producer surplus in the HOPS market areas (by +0.12 million EUR) while significantly decreasing consumer surplus (by - 6.05 million EUR).

The "Caveats" section in the Executive Summary, and the Conclusions section in Chapter 6 explain why these few cases of negative SEW reflect the conservative nature of this analysis, and are probably short-lived and unlikely in the real world.

4.2 Set of scenarios with dry hydrological conditions

4.2.1 Separated (non-coupled) markets (SM)

We depict the electricity generation mix and consumption in SEE for the EMI scenario with dry hydrological conditions (the "Dry" scenario) in Figure 41. With separated markets, total generation in SEE in 2025 would be 277.89 TWh, and total consumption would be 274.283 TWh. Across the region, annual generation would vary, from 3.71 TWh in ME to almost 66.2 TWh in RO. In each country, in comparison to baseline scenario, generation is notable lower due to dry hydrology. Generation in HPPs in comparison to the baseline scenario is lower by 14.6 TWh, or 23%. In dry hydrological conditions, the HPPs in SEE provide around 18% of total generation.

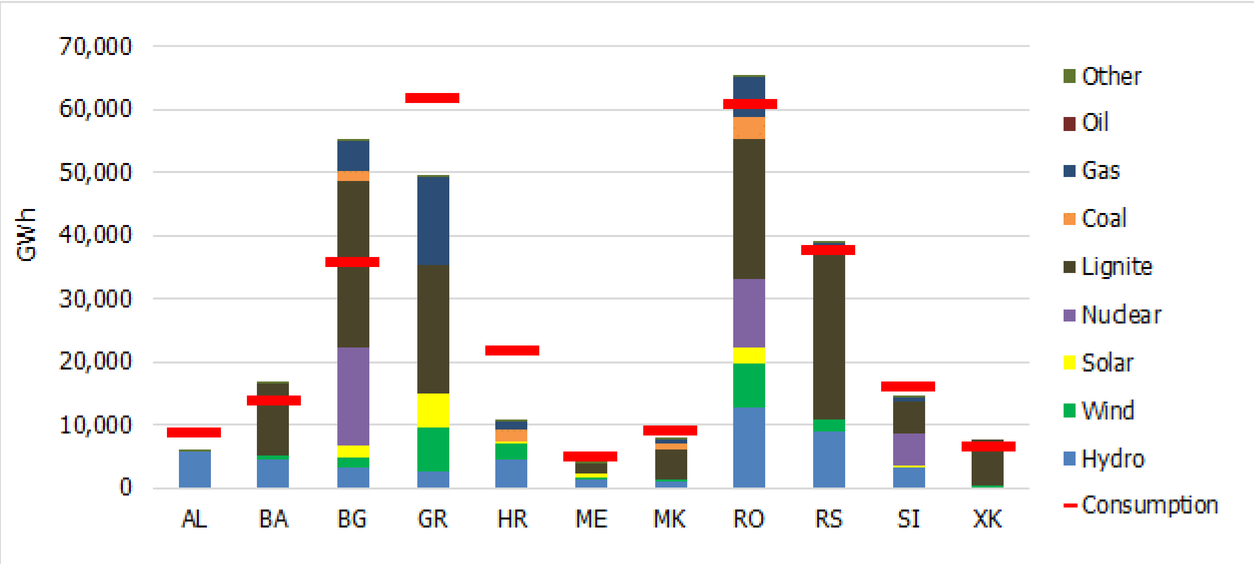


Figure 41: Electricity generation mix and consumption by market area in 2025 (Dry hydro conditions – SM)

The electricity generation mix by market area is presented in more detail in the following table.

Table 42: Electricity generation mix by market area in 2025 (Dry hydrological conditions – SM)

Yearly generation (TWh)	AL	BA	BG	GR	HR	ME	MK	RO	RS	SI	XK	SEE
HPP	5.65	4.63	3.50	3.02	4.89	1.44	1.03	12.71	9.20	3.80	0.13	**50.00**
TPP lignite	0.00	11.55	26.54	20.21	0.00	1.55	4.85	22.09	27.42	5.10	7.15	**126.46**
TPP coal	0.00	0.00	1.33	0.00	1.78	0.00	0.71	3.53	0.00	0.00	0.00	**7.35**
TPP gas	0.00	0.00	4.75	13.89	1.42	0.00	0.87	6.52	0.51	0.49	0.00	**28.45**
TPP oil	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	**0.03**
TPP other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.99	0.00	0.00	0.00	**0.99**
Nuclear	0.00	0.00	15.43	0.00	0.00	0.00	0.00	10.78	0.00	5.12	0.00	**31.33**
Solar	0.07	0.07	1.88	5.33	0.56	0.41	0.09	2.52	0.01	0.39	0.08	**11.42**
Wind	0.15	0.62	1.77	7.01	2.27	0.30	0.18	7.06	2.17	0.04	0.30	**21.86**
TOTAL	**5.86**	**16.86**	**55.21**	**49.49**	**10.92**	**3.71**	**7.74**	**66.20**	**39.31**	**14.94**	**7.66**	**277.89**

Regardless of this decrease in hydro generation, the SEE generation mix does not change substantially from the baseline scenario. Fossil fuels (TPPs) still dominate, except in the OST, HOPS, and CGES market areas, where HPPs have the highest share. Also, in the TransElectrica, ELES and ESO EAD market areas, nuclear generation still has a high share, while in the ADMIE/IPTO and TransElectrica areas, RES provides a significant share of generation with separated markets.

We present the electricity balances i.e. yearly consumption, generation and exchange values for each SEE market area in the SM scenario with "dry" conditions in Table 43. ESO EAD market area and TransElectrica market areas have the highest positive net interchange, 19.67 TWh and 5.6 TWh, respectively, meaning they are the main net exporters in SEE, while the ADMIE/IPTO and HOPS market areas are significant net importers, with around 12.1 TWh and 10.5 TWh, respectively. The OST and ELES market areas, which were balanced in the baseline scenario, now import electricity, due to the decrease in HPP generation. In relative terms, the export from the ESO EAD market area is more than 50% of its demand, while HOPs imports almost 50% of its demand. In dry hydrological conditions, the OST market area (with a high share of HPPs) imports more than 30% of its demand.

The SEE region as a whole (without Hungary) under separated markets exports around 3.6 TWh to neighboring power systems, which is significantly less than in the baseline scenario (9.3 TWh). These market areas keep more of their generation "at home" when conditions are dry. This indicates the relatively high dependence of this region on hydrological conditions.

Table 43: Electricity balance in 2025 (Dry hydrological conditions – SM)

Electricity balance	Cons. (GWh)	Gener. (GWh)	Pump load (GWh)	Custom. load (GWh)	Imports (GWh)	Exports (GWh)	Transit (GWh)	Net inter-change (GWh)	Net import / export share (%)
AL	8430	5861	0	8430	2934	365	732	-2570	-30.5%
BA	13534	16858	249	13285	222	3546	699	3324	24.6%
BG	35551	55209	489	35062	0	19658	2239	19658	55.3%
GR	61613	49486	417	61248	12157	31	3978	-12126	-19.7%
HR	21432	10919	377	21054	10577	65	1070	-10513	-49.1%
ME	4774	3706	0	4774	1447	379	3182	-1068	-22.4%
MK	8890	7738	0	8890	1267	116	2554	-1151	-12.9%
RO	60571	66200	0	60571	222	5850	3045	5629	9.3%
RS	37423	39309	519	36904	681	2565	2994	1885	5.0%
SI	15726	14942	874	14852	1446	662	13251	-784	-5.0%
XK	6340	7660	0	6340	86	1406	1022	1320	20.8%
SEE	274283	277887	2926	271410	31039	34643		3604	1.3%

We calculate consumption in the table above by adding customer load (demand) and load for pumped storage HPPs, and subtracting energy not supplied (if it exists). Customer load is a predefined hourly input time series of demand. Pump load values will change in different scenarios based on the operation of HPPs in pumping mode.

We calculate generation with separated markets in the table above by summing up the generation of all modelled power plants, without curtailed generation (if it exists).

We present export and import values in Table 43 and depict them in Figure 42, with transits in Figure 43, and net interchanges in Figure 44. These figures also depict the neighboring power systems. Of these systems, Hungary and Turkey mainly import electricity from SEE, while Central Europe mainly exports to SEE. Unlike in the baseline scenario, in the "dry" scenario, Italy exports electricity to SEE. ELES' market area has the highest level of transit, due to borders with large importers such as Hungary and Croatia, and large exporters such as CE and Italy.

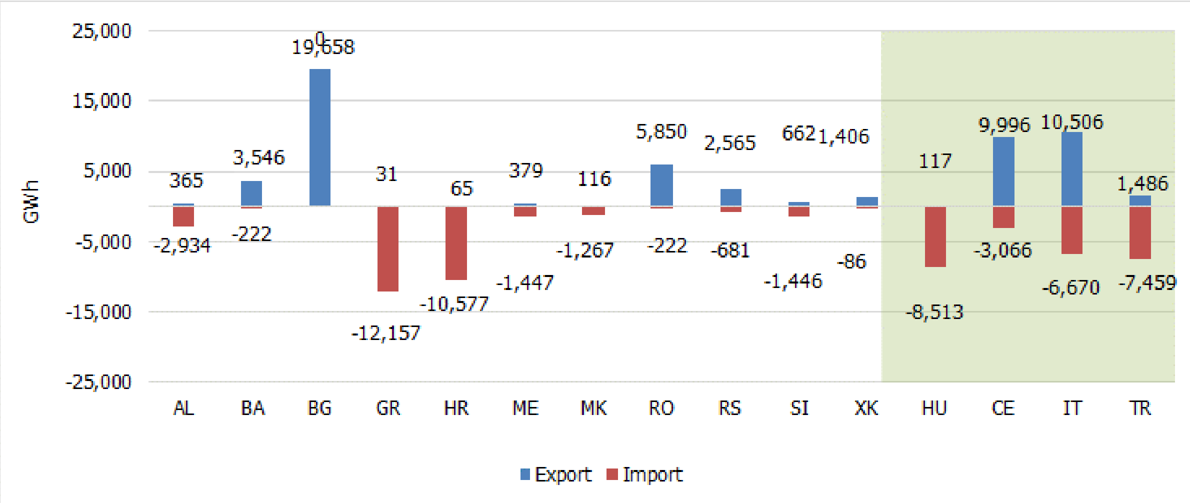


Figure 42: Imports and exports in 2025 (Dry hydrological conditions – SM)

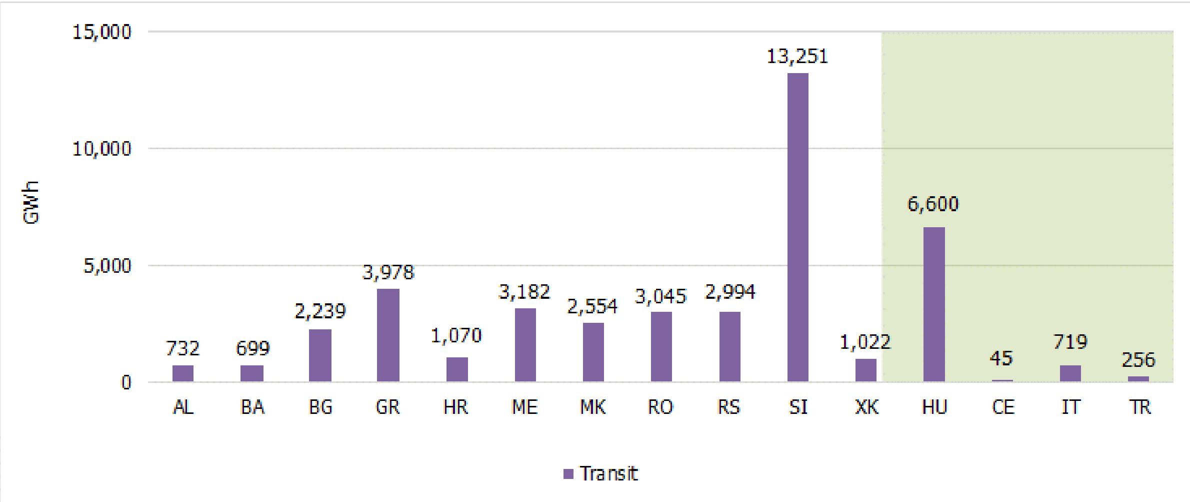


Figure 43: Transits in 2025 (Dry hydrological conditions – SM)

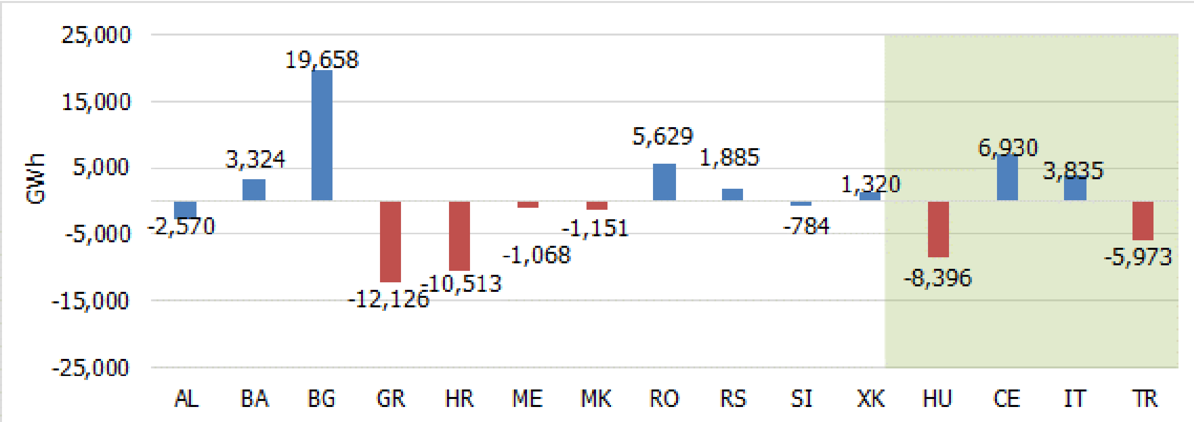


Figure 44: Net interchange in 2025 (Dry hydrological conditions – SM)

The differences among SEE market areas are largely based on operating costs, with results shown in Table 44. Generation operating costs include fuel, CO_2 and O&M. and the market price is set by the marginal operating costs of generation.

Average operating costs in the SEE region amount to 14.57 €/MWh. The highest operating costs are in the ADMIE/IPTO market area (19.98 €/MWh), where gas and coal TPPs have the highest share of generation. Table 44 also shows yearly CO_2 emissions in the SEE region. The highest level of CO_2 emissions is in the TransElectrica and EMS market areas, with high shares of coal (lignite) plants. Average total operating costs, which include carbon costs, amount to 28.13 €/MWh in the SEE region. The KOSTT market area has the highest total unit operating cost (37.04 €/MWh) followed by MEPSO (36.73 €/MWh), because in these areas, the majority of generation comes from coal TPPs with high CO_2 emissions. There is an increase in operating costs and CO_2 emissions in the "dry" scenario compared with the baseline due to the decrease of low-cost, CO2-free HPP generation and the greater use of expensive TPPs.

In this scenario, average SEE regional wholesale market price are 58.7 €/MWh. Average prices are annual load-weighted average values, and not simple averages, since load-weighted average values are better indicators of overall system performance. Generally, wholesale electricity prices are harmonized in the region, but there are variations. The highest average price is in the ADMIE/IPTO market area (69.57 €/MWh), followed by the HOPS and OST market areas with somewhat higher than average wholesale prices in the SEE region. The lowest price is in the TransElectrica and ESO EAD market areas, 54.00 €/MWh and 53.92 €/MWh. Due to higher costs and emissions, prices are higher in the "dry" scenario than in baseline, especially for hydro-dependent power system, like OST.

Table 44: Operating costs in 2025 (Dry hydrological conditions – SM)

Operating costs without and with emissions costs	AL	BA	BG	GR	HR	ME	MK	RO	RS	SI	XK	SEE
Operating costs (mil. €)	0	182	914	989	125	24	129	1,000	418	166	100	**4,049**
CO_2 emissions (mil. tonne)	0	14	27	25	2	2	6	29	29	5	7	**147**
CO_2 emissions costs (mil. €)	0	372	707	637	59	40	155	750	737	130	183	**3,769**
Total operating costs (mil. €)	0	554	1,621	1,626	184	63	284	1,750	1,156	296	284	**7,818**
Average operating costs (€/MWh)	0.00	10.79	16.56	19.98	11.47	6.41	16.70	15.11	10.64	11.13	13.11	**14.57**
Average total operating costs (€/MWh)	0.00	32.86	29.36	32.85	16.87	17.08	36.73	26.43	29.40	19.82	37.04	**28.13**
Price (€/MWh)	58.51	56.00	53.92	69.57	59.03	56.32	56.97	54.00	55.29	57.42	57.08	**58.70**

Yearly cross-border exchange, loading and congestions results are analyzed in later chapters.

When analyzing individual border flows, we see the highest yearly flow on the BG-GR border (see Table 45), from the ESO EAD market area to the ADMIE/IPTO market area.

Table 45: Cross-border exchange in 2025 (Dry hydrological conditions – SM)

Market area	Flow (GWh)														
	AL	BA	BG	GR	HR	HU	ME	MK	RO	RS	SI	XK	CE	IT	TR
AL	-			374			441	177				103			
BA		-			2,929		968			348					
BG			-	10,817				1,945	2,593	849					5,694
GR	247		0	-				336						1,405	2,021
HR		115			-	183				51	786				
HU					2,770	-			483	238	1,809		1,418		
ME	1,070	194					-			76		346		1,873	
MK	898		0	1,616				-		56		99			
RO			1,312			5,609			-	1,974					
RS		611	210		1,340	1,254	537	857	191	-		560			
SI					4,609	3,499					-		1,694	4,111	
XK	1,450						388	507		83		-			
CE						4,568					5,473		-		
IT				2,302			2,294				6,629			-	
TR			717	1,025											-

To better assess particular borders, we show the percentage cross-border loadings in Table 46. Cells in red have high flows with loadings above 50%, while cells in green show low flows, with loadings below 10%. In the baseline scenario, the highest loadings are on the BG-GR border (92%, into the ADMIE/IPTO area), consistent with the high border flows in the previous table. High loadings also occur on the BG-MK border (89%, towards North Macedonia) and the BG-TR border (72%, towards

Turkey). Almost all links to the ADMIE/IPTO market area and Turkey are highly loaded. Given EMS' central position in the region, there are high loadings going east and west, as energy flows mainly from the ESO EAD and TransElectrica market areas to the HOPS and HU market areas.

Table 46: Cross-border loading in 2025 (Dry hydrological conditions – SM)

Market area	Loading (%)														
	AL	**BA**	**BG**	**GR**	**HR**	**HU**	**ME**	**MK**	**RO**	**RS**	**SI**	**XK**	**CE**	**IT**	**TR**
AL	-			34			20	10				4			
BA		-			60		37			13					
BG			-	92				89	25	49					72
GR	23		0	-				9						32	58
HR		3			-	2				2	7				
HU					26	-			6	9	17		20		
ME	49	7					-			6		26		36	
MK	34		0	45				-		6		11			
RO			14			58			-	45					
RS		23	12		61	48	41	60	5	-		43			
SI					41	33					-		20	29	
XK	53						30	36		5		-	0		
CE						65					66		-		
IT				53			44				46			-	
TR			16	27											-

Cross-border loadings in both directions, i.e. sum of loadings in reference and counter-reference directions are depicted in the Figure 45. With blue bars are presented borders that are coupled in all scenarios, while with orange bars borders that are non-coupled in SM scenario.

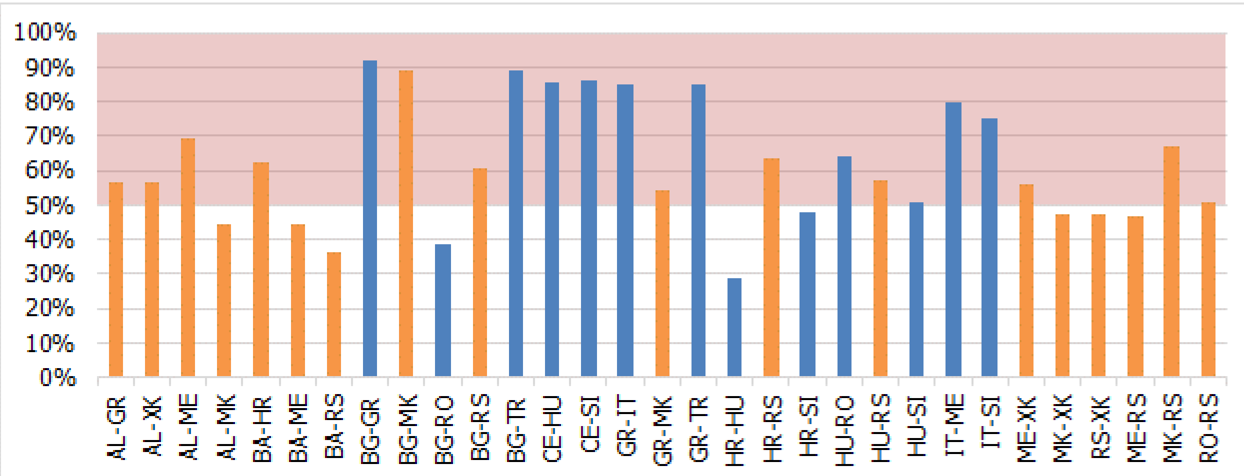


Figure 45: Cross-border loadings in both directions in 2025 (Dry hydrological conditions – SM)

Figure 45 shows loadings in both directions from 24% to 94% depending on the border. We note high loadings in both directions (above 50%) on the AL-GR, AL-XK, AL-ME, BA-HR, BG-MK, BG-RS, GR-MK, HR-RS, HU-RS, ME-XK and MK-RS borders.

The cross-border congestion probability is the number of annual hours in which flows on interconnections equals the modelled NTC, divided by the total number of hours (8760). We present the cross-border congestion probability for each border in Table 47. Cells in red show high congestion (i.e. probability above 50%), with cells in green having low congestion probability below 10%. Significant congestion probabilities show on the BG-GR, BG-MK, BG-TR borders, from Bulgaria and, CE-HU and CE-SL in direction from CE. This is expected, given the large exporting and importing areas in the North and South of the region. Other borders with high congestion probabilities are the RS-HR and RS- MK borders (from the EMS market area), which are non-coupled in the SM scenario.

Table 47: Cross-border congestion probability in 2025 (Dry hydrological conditions – SM)

Market area	Congestion probability (%)														
	AL	BA	BG	GR	HR	HU	ME	MK	RO	RS	SI	XK	CE	IT	TR
AL	-			32			16	7				2			
BA		-			46		28			9					
BG			-	82				84	11	46					70
GR	21		0	-				6						32	57
HR		1			-	0				2	1				
HU					4	-			2	7	3		19		
ME	45	4					-			5		21		34	
MK	21		0	33				-		7		11			
RO			6			52			-	36					
RS		17	11		58	45	39	55	4	-		38			
SI					33	19					-		19	26	
XK	35						27	26		3		-	0		
CE						64					62		-		
IT				51			41				36			-	
TR			17	27											-

4.2.2 Partial market coupling (PMC)

We show the electricity generation mix and consumption in the SEE region for PMC in the "Dry" scenario in Figure 46. Total generation in this region in 2025 amounts to 279.18 TWh, while total consumption is 274.570 TWh. The highest generation is in the TransElectrica market area, while the CGES market area has the lowest generation.

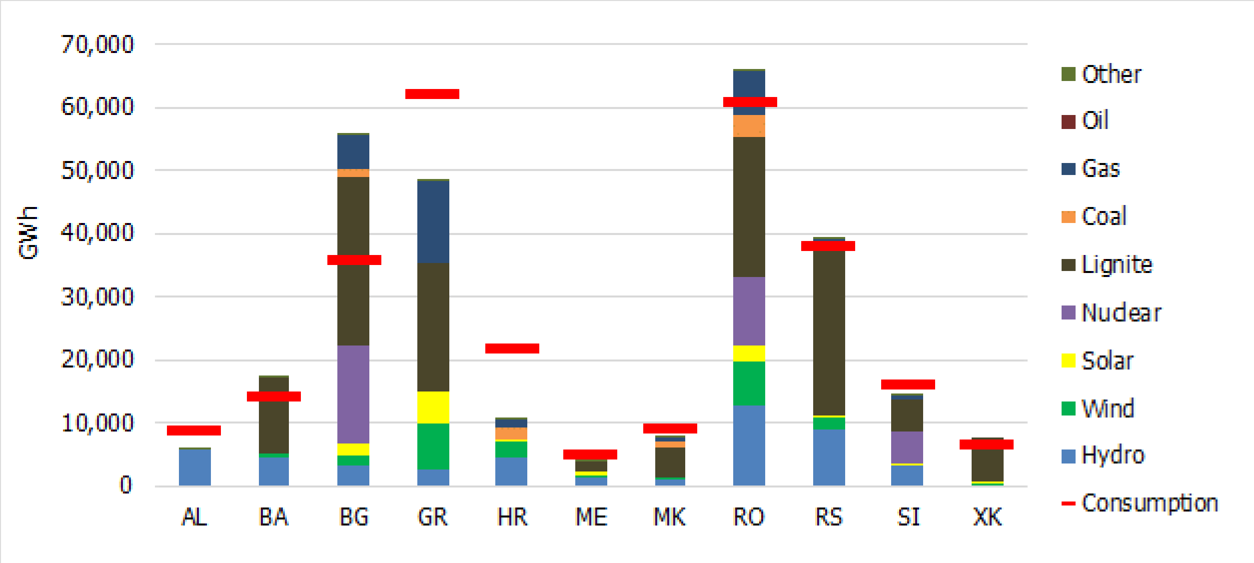


Figure 46: Electricity generation mix and consumption by market area in 2025 (Dry hydro conditions – PMC)

We show the generation mix by market area in detail under PMC and "dry" conditions in the following table.

Table 48: Electricity generation mix by market area in 2025 (Dry hydrological conditions – PMC)

Yearly generation (TWh)	AL	BA	BG	GR	HR	ME	MK	RO	RS	SI	XK	SEE
HPP	5.65	4.75	3.51	3.03	4.87	1.44	1.03	12.71	9.31	3.76	0.13	**50.19**
TPP lignite	0.00	12.00	26.63	20.14	0.00	1.55	4.85	22.21	27.55	5.11	7.17	**127.21**
TPP coal	0.00	0.00	1.41	0.00	1.76	0.00	0.73	3.64	0.00	0.00	0.00	**7.55**
TPP gas	0.00	0.00	5.26	13.09	1.41	0.00	0.88	6.84	0.61	0.48	0.00	**28.57**
TPP oil	0.00	0.00	0.00	0.02	0.00	0.00	0.01	0.00	0.00	0.00	0.00	**0.02**
TPP other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.04	0.00	0.00	0.00	**1.04**
Nuclear	0.00	0.00	15.43	0.00	0.00	0.00	0.00	10.78	0.00	5.12	0.00	**31.33**
Solar	0.07	0.07	1.88	5.33	0.56	0.41	0.09	2.52	0.01	0.39	0.08	**11.42**
Wind	0.15	0.62	1.77	7.01	2.27	0.30	0.18	7.06	2.17	0.04	0.30	**21.86**
TOTAL	**5.86**	**17.43**	**55.90**	**48.63**	**10.87**	**3.71**	**7.78**	**66.80**	**39.65**	**14.89**	**7.68**	**279.18**

As in previous scenarios, across the SEE market areas, fossil-fuel-powered TPPs have the highest share, except in the OST, HOPS and CGES market areas, where HPPs have the highest share, even in these dry hydrological conditions. There are nuclear power plants in the TransElectrica, ELES and ESO EAD market areas, while GR and RO are the leaders in RES generation.

The electricity balances (i.e., yearly consumption, generation and exchange values) for each SEE market area in the "dry" scenario under PMC are shown in Table 49. In absolute values, the largest net exporters are the ESO EAD and TransElectrica market areas, with 20.28 TWh and 6.28 TWh, respectively. The largest net importers are the ADMIE/IPTO and HOPS market areas, with 12.52 TWh and 10.46 TWh, respectively. Contrary to the baseline scenario, ELES and OST are importers.

Table 49: Electricity balance in 2025 (Dry hydrological conditions – PMC)

Electricity balance	Cons. (GWh)	Gener. (GWh)	Pump load (GWh)	Custom. load (GWh)	Imports (GWh)	Exports (GWh)	Transit (GWh)	Net inter-change (GWh)	Net import / export share (%)
AL	8430	5861	0	8430	3051	484	851	-2567	-30.5%
BA	13694	17431	409	13285	190	3761	942	3570	26.1%
BG	35566	55895	504	35062	0	20275	2601	20275	57.0%
GR	61663	48627	439	61248	12557	42	4009	-12515	-20.3%
HR	21397	10866	343	21054	10485	28	1879	-10457	-48.9%
ME	4774	3706	0	4774	1583	482	3215	-1101	-23.1%
MK	8890	7775	0	8890	1377	159	3918	-1218	-13.7%
RO	60571	66800	0	60571	186	6462	2738	6276	10.4%
RS	37568	39649	664	36904	841	2433	3652	1592	4.2%
SI	15676	14894	824	14852	1545	621	13857	-924	-5.9%
XK	6340	7676	0	6340	396	1234	1210	838	13.2%
SEE	274570	279182	3184	271410	32210	35981		3771	1.4%

The annual export, import, net interchange values and transits are presented in Table 49, and depicted in Figure 47, Figure 48 and Figure 49, now with neighboring countries and regions.

Regarding the neighboring power systems, Hungary and Turkey mostly import electricity from SEE, and Central Europe and Italy are exporters. The ELES market area has the highest transit, due to borders with huge importers such as Hungary and Croatia and large exporters such as CE and Italy. This is in line with border flows presented in Table 51.

As in the SM case, when analyzing individual flows on each border, we note in Table 45 that the highest absolute yearly flow is on the BG-GR border, flowing from the ESO EAD to the ADMIE/IPTO market area. Other large importers include the HOPS market area and Hungary.

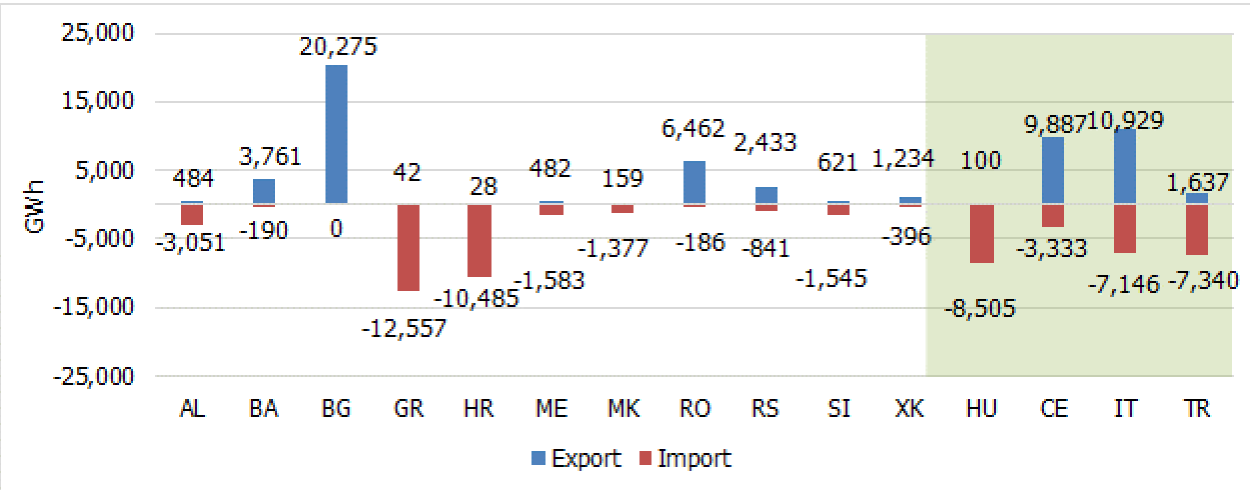


Figure 47: Imports and exports in 2025 (Dry hydrological conditions – PMC)

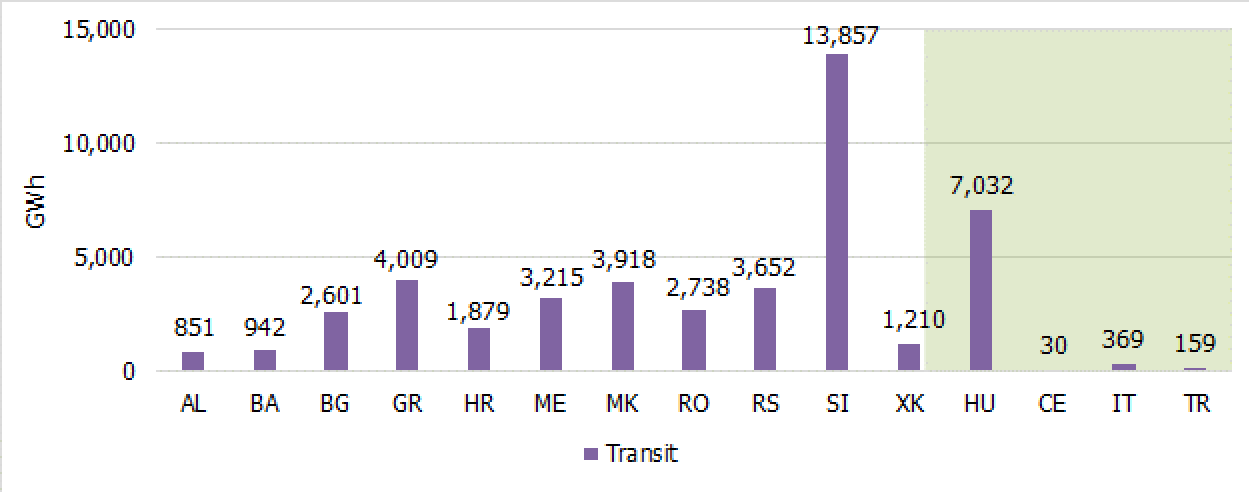


Figure 48: Transits Imports and exports in 2025 (Dry hydrological conditions – PMC)

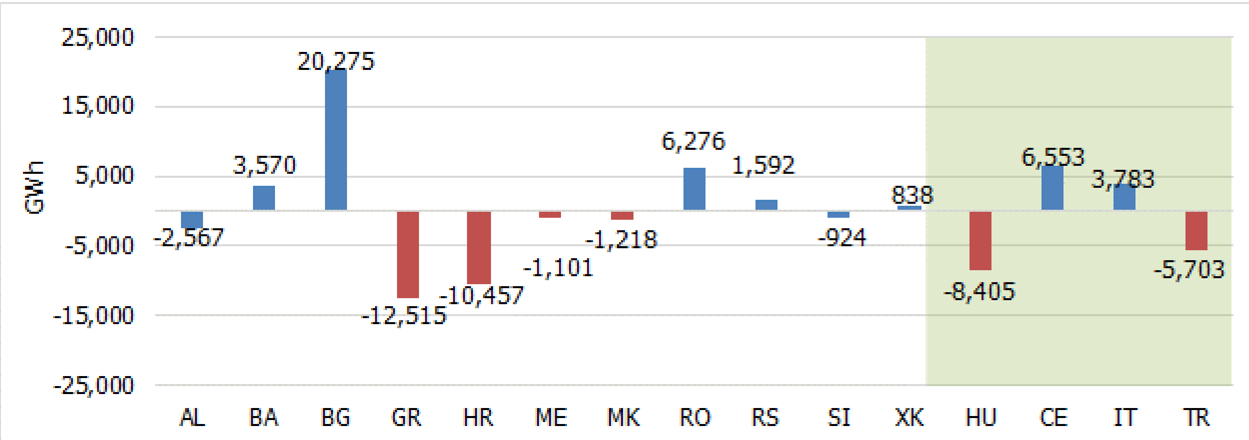


Figure 49: Net interchange in 2025 (Dry hydrological conditions – PMC)

We present the operating costs and prices for SEE in Table 50.

The average operating costs in SEE under PMC and dry conditions are 14.58 €/MWh. The highest operating cost is in the ADMIE/IPTO market area (19.46 €/MWh), and the highest CO_2 emissions are in the TransElectrica and EMS market areas, due to their large share of coal TPPs. Average total operating costs, including CO_2 emission costs, amount to 28.18 €/MWh in the SEE region. The KOSTT market areas has the highest average total operating cost (37.05 €/MWh) followed by the MEPSO market area (36.85 €/MWh), due to a high share of TPPs and carbon costs.

In the baseline scenario, with PMC, the average SEE wholesale market price is 58.04 €/MWh. Prices vary from 54.65 €/MWh in ESO EAD market area, to 63.78 €/MWh in the ADMIE/IPTO market area. As in the SM case, the dry scenario has higher operating costs, CO2 emissions and prices compared to the baseline scenario.

Table 50: Operating costs in 2025 (Dry hydrological conditions – PMC)

Operating costs without and with emissions costs	AL	BA	BG	GR	HR	ME	MK	RO	RS	SI	XK	SEE
Operating costs (mil. €)	0	189	942	946	124	24	131	1,023	425	165	101	**4,071**
CO_2 emissions (mil. tonne)	0	15	28	24	2	2	6	30	29	5	7	**148**
CO_2 emissions costs (mil. €)	0	387	715	628	58	40	156	758	742	130	184	**3,797**
Total operating costs (mil. €)	0	576	1,658	1,574	182	63	287	1,782	1,167	295	284	**7,868**
Average operating costs (€/MWh)	0.00	10.85	16.86	19.46	11.41	6.41	16.83	15.32	10.72	11.11	13.11	**14.58**
Average total operating costs (€/MWh)	0.00	33.05	29.65	32.37	16.80	17.08	36.85	26.67	29.43	19.82	37.05	**28.18**
Price (€/MWh)	60.01	57.59	54.65	63.78	58.77	57.44	58.04	54.66	56.87	57.09	59.08	**58.04**

As in the SM case, on individual borders, we note in Table 51 that the highest absolute yearly flow in the PMC dry condition is at the BG-GR border, from the ESO EAD to the ADMIE/IPTO market area.

Table 51: Cross-border exchange in 2025 (Dry hydrological conditions – PMC)

Market area	Flow (GWh)														
	AL	BA	BG	GR	HR	HU	ME	MK	RO	RS	SI	XK	CE	IT	TR
AL	-			308			517	214				296			
BA		-			3,959		576			166					
BG			-	10,392				3,865	2,285	905					5,430
GR	311		0	-				220						1,451	2,069
HR		99			-	290				36	1,483				
HU					2,556	-			513	526	1,963		1,574		
ME	1,045	332					-			130		467		1,723	
MK	1,052		0	2,619				-		153		253			
RO			1,592			5,286			-	2,322					
RS		701	203		1,129	1,797	860	679	126	-		590			
SI					4,719	3,629					-		1,789	4,340	
XK	1,494						378	317		255		-			
CE						4,535					5,381		-		
IT				2,256			2,466				6,575			-	
TR			806	990											-

Table 52 shows the percentage loading value for each border, to provide better insight in interconnection utilization. Cells colored in red show high flows, above 50%, while cells colored in green show low flows, below 10%. In this scenario the highest cross-border loading values occur on the BG-GR border (88%, towards the ADMIE/IPTO market area), consistent with the high flows on that border in the prior table. High loadings also occur on the BG-MK (88%, direction to MEPSO market area) and BG-TR borders (69%, direction to Turkey). Generally, almost all links to the ADMIE/IPTO market area and Turkey are highly loaded. TransElectrica and ESO EAD have high relative loadings in the export direction; EMS has high export loading on borders with HR, HU and ME; while GR, TR and IT have high import loadings. This situation depicts the main sources, sinks and directions of energy flow in the region.

Table 52: Cross-border loading in 2025 (Dry hydrological conditions – PMC)

Market area	Loading (%)														
	AL	**BA**	**BG**	**GR**	**HR**	**HU**	**ME**	**MK**	**RO**	**RS**	**SI**	**XK**	**CE**	**IT**	**TR**
AL	-			28			24	12				11			
BA		-			81		22			6					
BG			-	88				88	22	52					69
GR	29		0	-				6						33	59
HR		2			-	3				2	14				
HU					24	-			6	20	19		23		
ME	48	13					-			10		36		33	
MK	40		0	73				-		18		29			
RO			17			55			-	53					
RS		27	12		52	69	66	48	4	-		45			
SI					42	35					-		22	31	
XK	54						29	22		15		-	0		
CE						65					65		-		
IT				52			47				46			-	
TR			18	26											-

We depicted the cross-border loadings in both directions (i.e., the sum of loadings in reference and counter-reference directions) in Figure 50. The blue bars show borders that are coupled in all scenarios, while the green bars are borders that are coupled only in the PMC scenario (AL-XK, BA-HR, BG-MK, GR-MK, HU-RS, ME-RS). The orange borders are non-coupled borders in the PMC scenario.

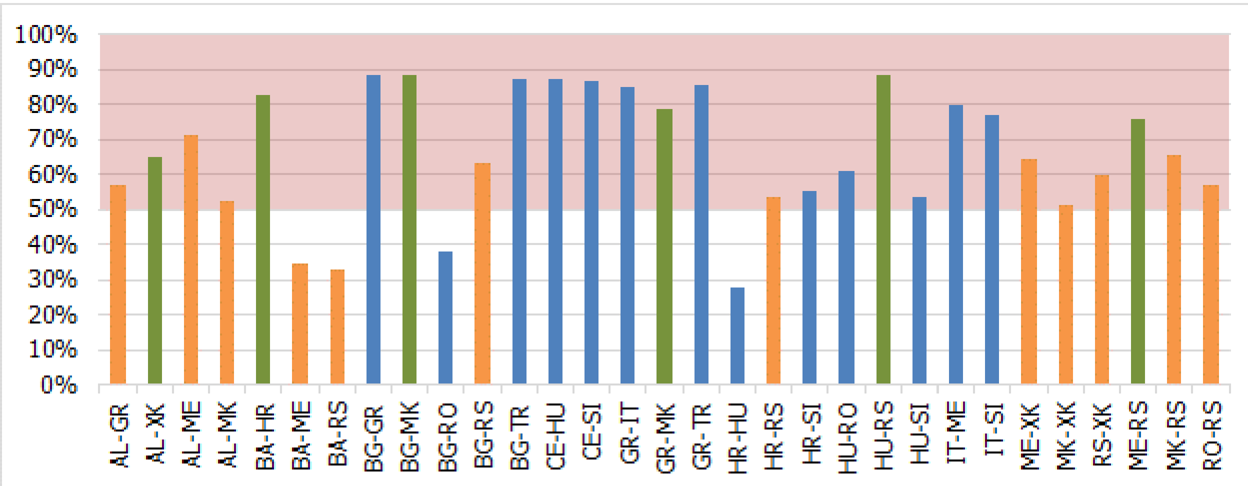


Figure 50: Cross-border loadings in both directions in 2025 (Dry hydrological conditions – PMC)

As shown in Figure 50, cross-border loadings in both directions range from 27% to 88% depending on the border. In the PMC scenario, all coupled borders are loaded above 50% compared to SM.

We present the probability of cross-border congestion on each border in Table 53. There is significant congestion probabilities (red colored cells), especially on the BG-GR, BG-TR, BG-MK and GR-TR borders, but only from the BG to the TR market area. The other non-coupled borders with high congestion probability is the RS-HR border (towards the HOPS market area).

Table 53: Cross-border congestion probability in 2025 (Dry hydrological conditions – PMC)

Market area	Congestion probability (%)														
	AL	**BA**	**BG**	**GR**	**HR**	**HU**	**ME**	**MK**	**RO**	**RS**	**SI**	**XK**	**CE**	**IT**	**TR**
AL	-			31			21	13				0			
BA		-			20		15			4					
BG			-	78				74	9	48					68
GR	24		0	-				0						33	59
HR		0			-	0				1	4				
HU					4	-			3	5	4		22		
ME	43	8					-			4		28		31	
MK	28		0	18				-		19		23			
RO			8			48			-	43					
RS		21	12		50	30	28	46	3	-		39			
SI					34	20					-		21	29	
XK	2						27	23		13		-	0		
CE						63					61		-		
IT				50			44				35			-	
TR			19	26											-

4.2.3 Full market coupling (FMC)

Electricity generation and consumption in the SEE region in the "dry" scenario with full market coupling (FMC) in 2025 amounts to 280.05 TWh and 274.238 TWh, respectively. As in other coupling scenarios, the highest generation is in the TransElectrica market area (67.72 TWh), while the CGES market area has the lowest electricity generation (3.71 TWh). Also, there are significant differences in a number of countries between consumption and production due to imports and exports.

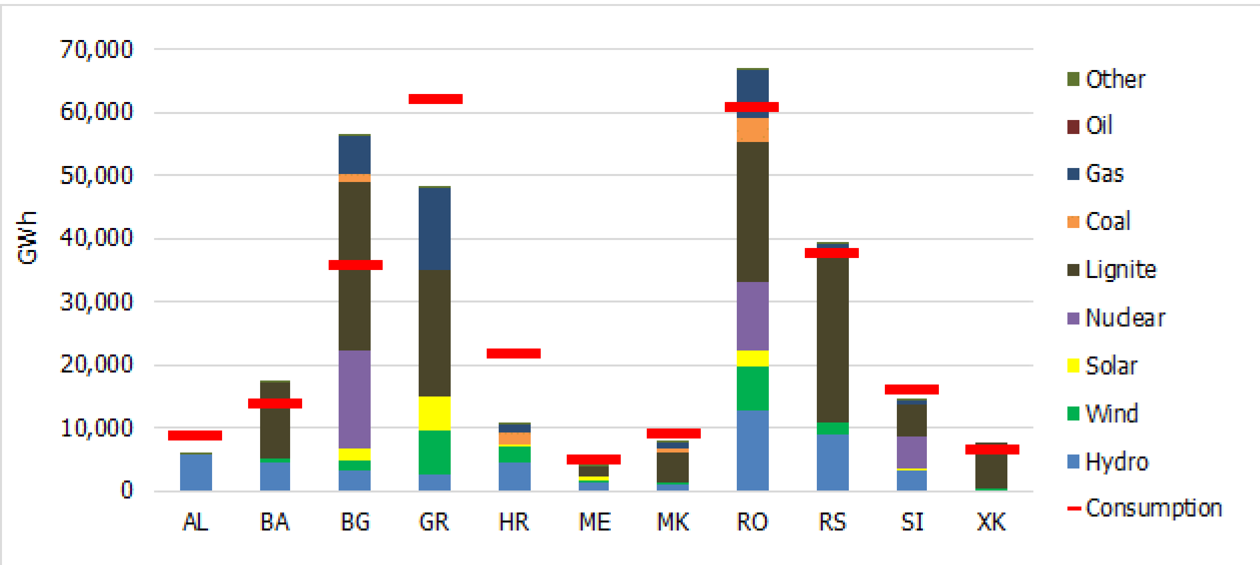


Figure 51: Electricity generation mix and consumption by market area in 2025 (Dry hydro conditions – FMC)

We present the FMC, "dry" generation mix by market area in more detail in the following table.

Table 54: Electricity generation mix by market area in 2025 (Dry hydrological conditions – FMC)

Yearly generation (TWh)	AL	BA	BG	GR	HR	ME	MK	RO	RS	SI	XK	SEE
HPP	5.65	4.65	3.52	3.05	4.86	1.44	1.03	12.71	9.16	3.74	0.13	**49.94**
TPP lignite	0.00	11.94	26.68	20.06	0.00	1.56	4.82	22.38	27.61	5.11	7.16	**127.32**
TPP coal	0.00	0.00	1.44	0.00	1.77	0.00	0.70	3.69	0.00	0.00	0.00	**7.60**
TPP gas	0.00	0.00	5.81	12.92	1.38	0.00	0.85	7.50	0.58	0.47	0.00	**29.51**
TPP oil	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	**0.01**
TPP other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.07	0.00	0.00	0.00	**1.07**
Nuclear	0.00	0.00	15.43	0.00	0.00	0.00	0.00	10.78	0.00	5.12	0.00	**31.33**
Solar	0.07	0.07	1.88	5.33	0.56	0.41	0.09	2.52	0.01	0.39	0.08	**11.42**
Wind	0.15	0.62	1.77	7.01	2.27	0.30	0.18	7.06	2.17	0.04	0.30	**21.86**
TOTAL	**5.86**	**17.27**	**56.53**	**48.40**	**10.82**	**3.71**	**7.68**	**67.72**	**39.52**	**14.87**	**7.67**	**280.05**

As in all other cases, TPPs have the highest share in the EMI region, except in the OST, HOPS and CGES market areas, where HPPs have the highest share. In addition, the TransElectrica, ELES and ESO EAD market areas have notable shares of nuclear generation. The least diversified generation mix is in the KOSTT market area where over 90% of generation comes from TPPs. Regarding wind and solar generation, GR and RO are the leading countries, with 12.3 TWh and 9.5 TWh.

We show the electricity balances (i.e., yearly consumption, generation, exchange and transit values) for each SEE market area in the FMC scenario in Table 55. The ESO EAD area and TransElectrica market areas have the highest net interchange value, meaning that they are the main net exporters in the SEE region, while the ADMIE/IPTO and HOPS market area are significant net importers, similar to the SM and PMC scenarios.

Table 55: Electricity balance in 2025 (Dry hydrological conditions – FMC)

Electricity balance	Cons. (GWh)	Gener. (GWh)	Pump load (GWh)	Custom. load (GWh)	Imports (GWh)	Exports (GWh)	Transit (GWh)	Net inter-change (GWh)	Net import / export share (%)
AL	8430	5861	0	8430	3253	683	1201	-2569	-30.5%
BA	13565	17274	280	13285	158	3867	1544	3709	27.3%
BG	35575	56526	513	35062	0	20951	2468	20951	58.9%
GR	61698	48397	466	61248	13542	241	4073	-13301	-21.6%
HR	21381	10824	327	21054	10574	16	2676	-10558	-49.4%
ME	4774	3708	0	4774	1488	423	4018	-1066	-22.3%
MK	8890	7680	0	8890	1400	191	4576	-1210	-13.6%
RO	60571	67720	0	60571	187	7337	2802	7149	11.8%
RS	37365	39520	461	36904	713	2868	5990	2155	5.8%
SI	15649	14873	797	14852	1402	626	14313	-776	-5.0%
XK	6340	7669	0	6340	88	1418	1380	1329	21.0%
SEE	274238	280051	2844	271410	32806	38620		5813	2.1%

We provided the yearly values for exports, imports, transits and net interchange for SEE market areas in Table 55, and we present them here for neighboring power systems as well. Figure 52 depicts export and import values, with transits in Figure 53 and net interchanges in Figure 54. Positive values are exports, while negative values are imports. In the SEE region, the ADMIE/IPTO and HOPS market areas are the highest net importers, with almost negligible exports, while the ESO EAD and TransElectrica market areas are the highest net exporters, with almost zero imports. Figure 53 shows that the highest transit in the region is through ELES in the SM and PMC cases. Regarding the neighboring power systems, the highest power transits are through Hungary. Also, Hungary and Turkey mostly import electricity from the SEE region, while Central Europe and Italy mostly exports electricity to the SEE region.

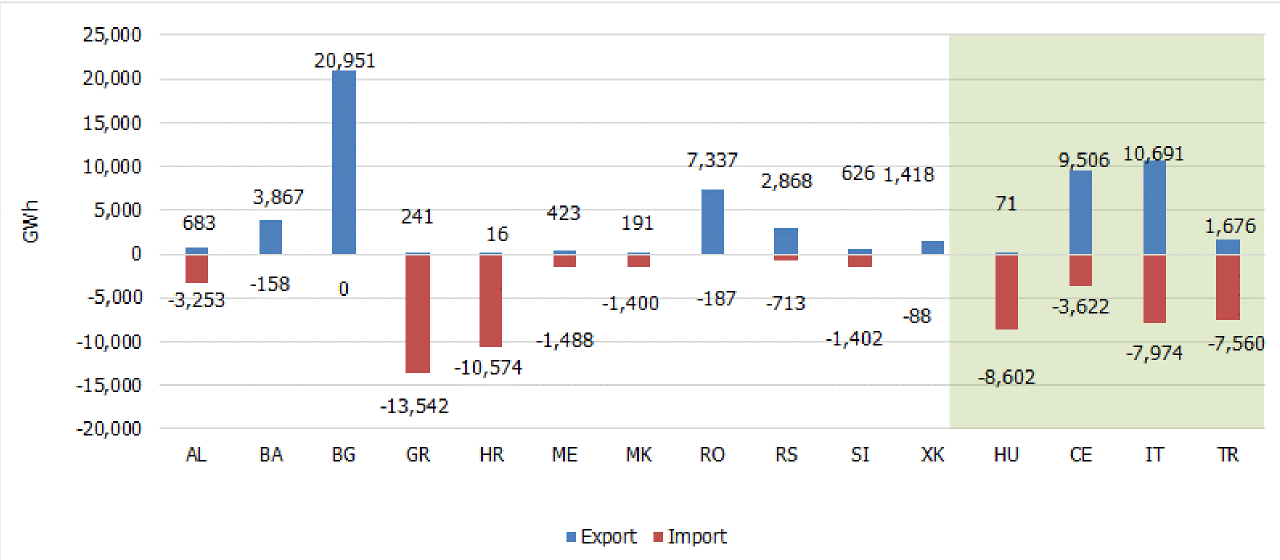


Figure 52: Imports and exports in 2025 (Dry hydrological conditions – FMC)

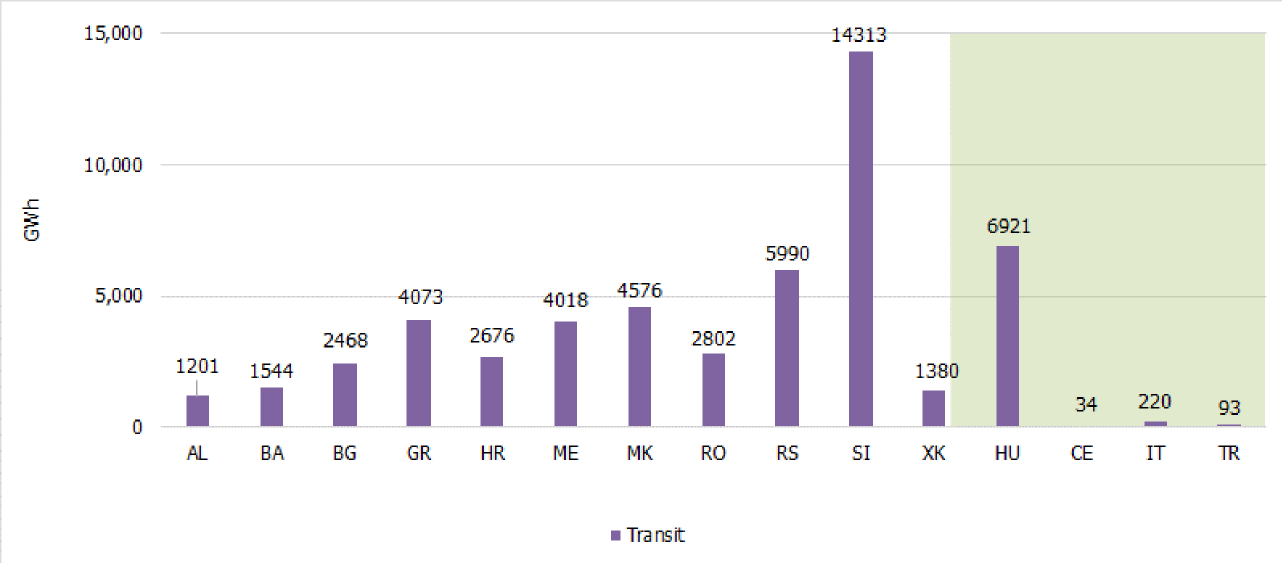


Figure 53: Transits in 2025 (Dry hydrological conditions – FMC)

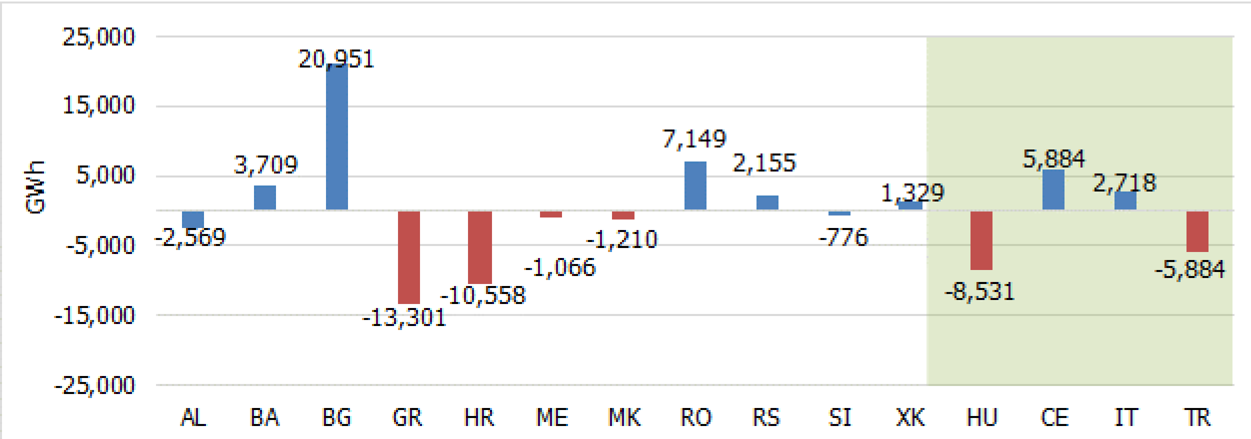


Figure 54: Net interchange in 2025 (Dry hydrological conditions – FMC)

The average operating costs in SEE region are 14.71 €/MWh, without considering CO_2 emission costs. The highest operating cost is in the ADMIE/IPTO market area (16.71 €/MWh), followed by ESO EAD (19.36 €/MWh). Table 56 also presents data for yearly CO_2 emissions in the SEE region and costs related to these emissions. The highest level of CO_2 emissions are in the TransElectrica and EMS market areas. Average total operating costs, which include also carbon costs, amount to 28.31 €/MWh in the SEE region, so CO2 adds 13.60 Euros per MWh to average operating costs. In terms of average total operating cost, the KOSTT market area has the highest value (37.04 €/MWh) followed by the MEPSO market area (36.57 €/MWh). This is due to the cost of carbon, which mostly affects the market areas with the highest share of coal-based TPPs.

In this scenario, the average SEE regional wholesale market price is 57.40 €/MWh. Generally, wholesale electricity prices are harmonized in the region, even more than in the case of the PMC scenario, but there are differences between markets. For example, the ADMIE/IPTO and HOPS market areas have the highest level of average wholesale prices in the modelled SEE region, 62.08 €/MWh and 58.60 €/MWh, while the ESO EAD and TransElectrica market area have the lowest prices (55.36 €/MWh and 55.46 €/MWh).

Table 56: Operating costs in 2025 (Dry hydrological conditions – FMC)

Operating costs without and with emissions costs	AL	BA	BG	GR	HR	ME	MK	RO	RS	SI	XK	SEE
Operating costs (mil. €)	0	188	970	937	122	24	127	1,060	424	165	101	**4,119**
CO_2 emissions (mil. tonne)	0	15	28	24	2	2	6	30	29	5	7	**148**
CO_2 emissions costs (mil. €)	0	385	722	624	58	40	154	770	743	130	184	**3,810**
Total operating costs (mil. €)	0	573	1,692	1,561	180	63	281	1,831	1,167	295	284	**7,928**
Average operating costs (€/MWh)	0.00	10.90	17.16	19.36	11.30	6.42	16.54	15.66	10.74	11.10	13.11	**14.71**
Average total operating costs (€/MWh)	0.00	33.18	29.94	32.26	16.67	17.09	36.57	27.03	29.54	19.83	37.04	**28.31**
Price (€/MWh)	56.62	56.27	55.36	62.08	58.60	56.04	55.64	55.46	55.71	56.80	56.04	**57.40**

Below we analyze yearly cross-border exchanges, loading and congestion.

The highest cross-border exchange (Table 57) is in the ELES market area, i.e. 30,653 GWh (14,938 GWh from the ELES market area to neighboring market areas, and 15,715 GWh in the opposite direction). The KOSTT market area has the lowest yearly cross-border exchange in the SEE region, which is 4,266 GWh (2,797 GWh from the KOSTT market area to the neighboring market areas, and 1468 GWh in the opposite direction). When analyzing individual flows per border, we note that the highest yearly flow is on the BG-GR border, going from the ESO EAD market area to the ADMIE/IPTO market area, which is the same pattern as in the SM and PMC scenarios.

Table 57: Cross-border exchange in 2025 (Dry hydrological conditions – FMC)

Market area	Flow (GWh)														
	AL	BA	BG	GR	HR	HU	ME	MK	RO	RS	SI	XK	CE	IT	TR
AL	-			792			708	246				139			
BA		-			4,239		991			180					
BG			-	10,303				3,466	2,454	1,719					5,477
GR	323		0	-				304						1,511	2,177
HR		107			-	430				59	2,096				
HU					2,073	-			464	587	2,134		1,734		
ME	1,714	353					-			62		337		1,975	
MK	979		0	3,394				-		194		200			
RO			1,336			5,063			-	3,740					
RS		1,241	287		2,335	1,951	887	1,294	71	-		792			
SI					4,602	3,705					-		1,923	4,708	
XK	1,438						529	667		163		-			
CE						4,374					5,166		-		
IT				2,202			2,390				6,318			-	
TR			845	924											-

We show yearly average cross-border loadings in Table 58, to provide insight into the utilization of each inter-connection. In this scenario, the highest cross-border loading also occurs on the BG-GR border (87%, towards the ADMIE/IPTO market area). High loadings also occur on the BG-MK and BG-TR borders. Generally, almost all links to ADMIE/IPTO market area and Turkey are highly loaded, as in the SM and PMC scenarios. The TransElectrica market areas cross-border lines have notably low loading values into TransElectrica, and is significantly higher in the opposite direction, showing that TransElectrica is also an exporter of electricity in the FMC scenario. This is also true for ESO EAD, while for HR and HU, it is vice versa, as they are importers. This table shows that the main directions of electricity flow remain the same as in the SM and PMC scenarios.

Table 58: Cross-border loading in 2025 (Dry hydrological conditions – FMC)

Market area	Loading (%)														
	AL	**BA**	**BG**	**GR**	**HR**	**HU**	**ME**	**MK**	**RO**	**RS**	**SI**	**XK**	**CE**	**IT**	**TR**
AL	-			36			16	7				3			
BA		-			43		19			3					
BG			-	87				79	23	49					70
GR	15		0	-				4						35	62
HR		1			-	5				1	19				
HU					20	-			5	11	20		25		
ME	39	7					-			2		13		38	
MK	19		0	47				-		11		11			
RO			14			53			-	43					
RS		24	8		53	37	34	46	1	-		30			
SI					41	35					-		23	34	
XK	26						20	23		5		-	0		
CE						63					62		-		
IT				50			46				44			-	
TR			19	24											-

The following Figure shows cross-border loadings in both directions, i.e. sum of loadings in the reference and counter-reference directions. Blue bars are borders that are coupled in all scenarios, while green bars show borders coupled in the FMC scenario. In this FMC scenario, all 18 borders shown in green bars are coupled (there are no non-coupled borders).

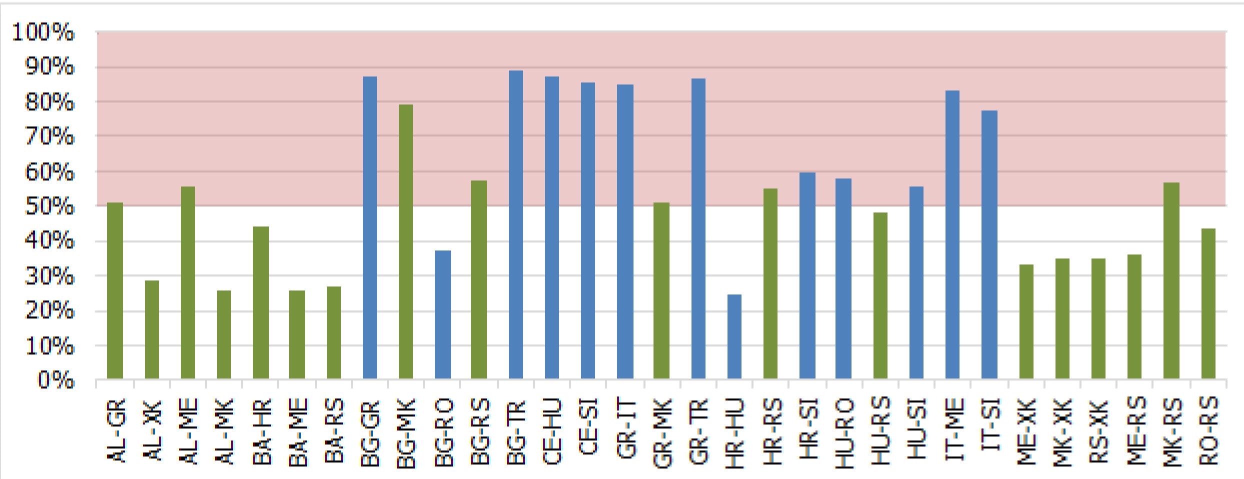


Figure 55: Cross-border loadings in both directions in 2025 (Dry hydrological conditions – FMC)

As Figure 55 shows, cross-border loadings in both directions range from 25% to 89%, depending on the border. When analyzing coupled borders, we note that high loadings still exist in both directions (i.e. above 50%) on the AL-GR, AL-MK, BG-MK, BG-RS, GR-MK, HR-RS, and MK-RS borders, but as expected, they are significantly lower than in the SM scenario.

The probability of cross-border congestion on each border is presented in Table 59. There are significant congestion probabilities, especially on the BG-GR, BG-TR, BG-MK and GR-TR borders, from Bulgaria and to Turkey. Borders which are coupled in this FMC scenario that were not coupled in the SM scenario all have loadings below 50% after coupling.

Table 59: Cross-border congestion probability in 2025 (Dry hydrological conditions – FMC)

Market area	Congestion probability (%)														
	AL	**BA**	**BG**	**GR**	**HR**	**HU**	**ME**	**MK**	**RO**	**RS**	**SI**	**XK**	**CE**	**IT**	**TR**
AL	-			33			11	3				0			
BA		-			28		6			1					
BG			-	75				65	11	45					68
GR	14		0	-				2						34	61
HR		0			-	1				1	8				
HU					2	-			2	7	5		24		
ME	26	1					-			2		8		37	
MK	8		0	28				-		11		10			
RO			5			45			-	27					
RS		11	6		47	33	26	39	0	-		23			
SI					36	21					-		22	31	
XK	3						13	13		2		-	0		
CE						62					59		-		
IT				50			45				35			-	
TR			20	25											-

4.2.4 Comparison of different market coupling scenarios

Below, we show the total electricity generation in the SEE region for dry hydrological conditions and the different market coupling scenarios, in both absolute values (TWh) and relative values (%), in Table 60. In all cases, we compare the results to the SM scenario.

Total electricity generation rises in the PMC scenario by 1.29 TWh (0.47%) and in the FMC scenario by 2.16 TWh (0.78%) compared to the SM scenario. This increase of electricity generation is caused by unlocking the potential for higher electricity exports with a higher share of NTCs under market coupling. In all MC scenarios, the highest generation is in the TransElectrica market area and the lowest in the CGES market area, but market coupling has an impact on specific market areas. For example, comparing Table 60 and Table 64 shows that the most significant increase in generation with market coupling occurs in export market areas (such as NOSBiH, TransElectrica and ESO EAD), while decreasing generation occurs in importing market areas (such as HOPS and ADMIE/IPTO). That increase or decrease in generation is mainly correlated with coupling; i.e., more extensive coupling produces more of an increase or decrease. This is because market coupling allows better utilization of NTCs and unlocks the prospects for more exports and imports, leading to greater generation by exporters, and lower generation by importers. In some market areas there is no significant change, for example in the OST and CGES market areas. This is due to a higher share of hydro generation, which is the same in all MC scenarios.

Table 60: Comparison of electricity generation by market area in 2025 (Dry hydrological conditions)

Yearly generation (TWh)	AL	BA	BG	GR	HR	ME	MK	RO	RS	SI	XK	SEE
Separated markets	5.86	16.86	55.21	49.49	10.92	3.71	7.74	66.20	39.31	14.94	7.66	**277.89**
Partial market coupling	5.86	17.43	55.90	48.63	10.87	3.71	7.78	66.80	39.65	14.89	7.68	**279.18**
Change (TWh)	0.00	0.57	0.69	-0.86	-0.05	0.00	0.04	0.60	0.34	-0.05	0.02	**1.29**
Change (%)	0.00	3.40	1.24	-1.74	-0.49	0.02	0.48	0.91	0.87	-0.32	0.22	**0.47**
Full market coupling	5.86	17.27	56.53	48.40	10.82	3.71	7.68	67.72	39.52	14.87	7.67	**280.05**
Change (TWh)	0.00	0.42	1.32	-1.09	-0.10	0.00	-0.06	1.52	0.21	-0.07	0.01	**2.16**
Change (%)	0.00	2.47	2.38	-2.20	-0.87	0.06	-0.75	2.30	0.54	-0.46	0.12	**0.78**

We compare the yearly export values in Table 61, import values in Table 62, and transit values in Table 63. These tables should be analyzed along with Figure 56. In all scenarios, the ADMIE/IPTO and HOPS market areas are the highest importers, and the ESO EAD, TransElectrica and NOSBiH market areas are the highest exporters, while greatest transit is through ELES. In total, regional export increase by 1338 GWh (3.86%) in the PMC scenario, and by 3977 GWh (11.48%) in FMC, while imports increase by 1171 GWh (3.77%) in the PMC scenario and 1768 GWh (5.69%) in FMC.

By considering the export and import tables, we come to these conclusions:

- First, on a regional level, exports increase more than imports, which says there are greater net exchanges in the PMC and FMC cases compared with SM. The region as whole exports more than before coupling, as transmission utilization is greater and supports higher exports of lowe-cost electricity to neighboring power systems, such as Hungary, Turkey and Italy.
- Second, when comparing individual countries across the scenarios, we conclude that the big exporters and importers have the highest increases in exports/imports. This is logical, given hat coupling allows better utilization of transmission, and thus unlocks generation in exporting areas to substitute for more expensive generation in importing areas.

In addition, Table 63 shows that in both cases (PMC and FMC), transits change notably, compared with the SM situation. Since transits represent flows of electricity through one system as a result of exchanges between two other systems, we conclude that market integration promotes energy exchanges and flows across the SEE region.

To summarize, coupling in the SEE region boosts net exports, especially of countries that already export, and raise the net export of the entire region. Some of the additional exports are redistributed between the SEE countries (i.e., some countries increase net imports), while the rest is exported to neighboring market areas, such as Hungary, Turkey and partially Italy.

Table 61: Comparison of export by market area in 2025 (Dry hydrological conditions)

Export (GWh)	AL	BA	BG	GR	HR	ME	MK	RO	RS	SI	XK	SEE
Separated markets	365	3,546	19,658	31	65	379	116	5,850	2,565	662	1,406	**34,643**
Partial market coupling	484	3,761	20,275	42	28	482	159	6,462	2,433	621	1,234	**35,981**
Change (GWh)	120	215	617	12	-37	103	43	611	-132	-41	-172	**1,338**
Change (%)	32.82	6.06	3.14	37.71	-56.69	27.19	37.16	10.45	-5.16	-6.19	-12.26	**3.86**
Full market coupling	683	3,867	20,951	241	16	423	191	7,337	2,868	626	1,418	**38,620**
Change (GWh)	319	321	1,292	211	-49	44	75	1,486	303	-36	11	**3,977**
Change (%)	87.50	9.05	6.57	684.57	-75.05	11.57	64.36	25.41	11.80	-5.43	0.79	**11.48**

Table 62: Comparison of import by market area in 2025 (Dry hydrological conditions)

Import (GWh)	AL	BA	BG	GR	HR	ME	MK	RO	RS	SI	XK	SEE
Separated markets	2,934	222	0	12,157	10,577	1,447	1,267	222	681	1,446	86	**31,039**
Partial market coupling	3,051	190	0	12,557	10,485	1,583	1,377	186	841	1,545	396	**32,210**
Change (GWh)	117	-32	0	400	-93	136	110	-36	161	99	309	**1,171**
Change (%)	3.98	-14.25	0	3.29	-0.88	9.40	8.64	-16.33	23.60	6.86	357.62	**3.77**
Full market coupling	3,253	158	0	13,542	10,574	1,488	1,400	187	713	1,402	88	**32,806**
Change (GWh)	319	-64	0	1,385	-4	42	133	-34	33	-44	2	**1,768**
Change (%)	10.86	-28.95	0	11.39	-0.03	2.87	10.50	-15.53	4.83	-3.02	2.38	**5.69**

Figure 56 depicts comparison of yearly exports and imports for different market coupling scenarios.

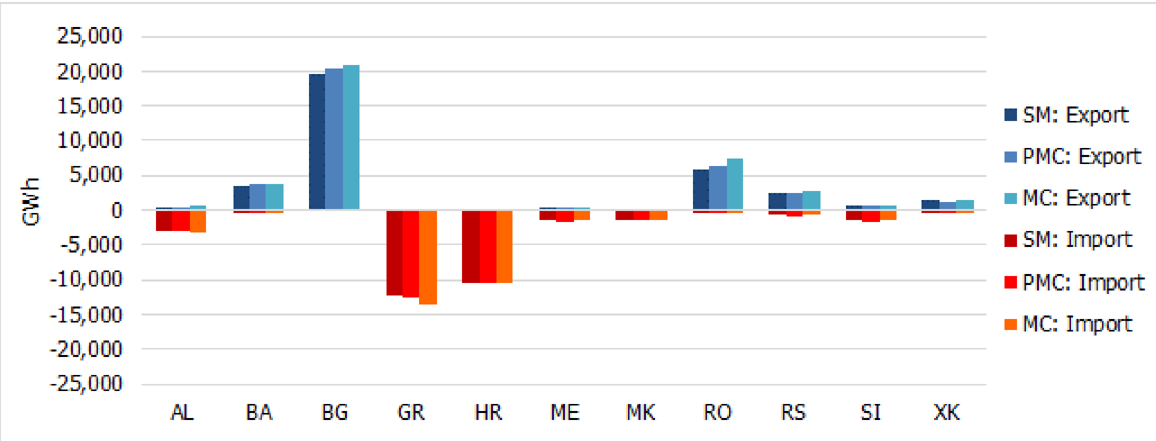


Figure 56: Comparison of exports and imports in 2025 (Dry hydrological conditions)

Table 63: Comparison of transits by market area in 2025 (Dry hydrology scenario)

Transit (GWh)	AL	BA	BG	GR	HR	ME	MK	RO	RS	SI	XK	SEE
Separated markets	732	699	2,239	3,978	1,070	3,182	2,554	3,045	2,994	13,251	1,022	**34,767**
Partial market coupling	851	942	2,601	4,009	1,879	3,215	3,918	2,738	3,652	13,857	1,210	**38,871**
Change (GWh)	119	243	362	31	809	34	1,364	-307	658	606	188	**4,104**
Change (%)	16.32	34.76	16.15	0.77	75.56	1.06	53.40	-10.09	21.97	4.57	18.36	11.81
Full market coupling	1,201	1,544	2,468	4,073	2,676	4,018	4,576	2,802	5,990	14,313	1,380	**45,039**
Change (GWh)	470	845	228	95	1,606	836	2,022	-243	2,995	1,061	358	**10,273**
Change (%)	64.19	120.93	10.19	2.39	149.99	26.27	79.17	-7.98	100.03	8.01	34.98	29.55

In order to adequately assess the net interchange increase and redistribution across the region, we evaluate the data in Table 64. When we sum up the changes in imports (negative net interchanges) we concluded that market coupling increases imports by 569 GWh in PMC and by 1267 GWh in FMC compared to the SM scenario. Also, market coupling unlocks generation in the exporting areas, and raises exports by 736 GWh in PMC and by 3477 GWh in FMC providing additional energy for the region, while also increasing regional exports (a substantial rise, from 167 GWh to 2,209 GWh).

Table 64: Comparison of net interchange by market area in 2025 (Dry hydrological conditions)

Net interchange (GWh)	AL	BA	BG	GR	HR	ME	MK	RO	RS	SI	XK	SEE
Separated markets	-2,570	3,324	19,658	-12,126	-10,513	-1,068	-1,151	5,629	1,885	-784	1,320	**3,604**
Partial market coupling	-2,567	3,570	20,275	-12,515	-10,457	-1,101	-1,218	6,276	1,592	-924	838	**3,771**
Change (GWh)	3	246	617	-389	56	-33	-66	648	-293	-140	-482	**167**
Full market coupling	-2,569	3,709	20,951	-13,301	-10,558	-1,066	-1,210	7,149	2,155	-776	1,329	**5,813**
Change (GWh)	0	385	1,292	-1,174	-45	2	-58	1,521	270	8	9	**2,209**

We show the exchanges of Hungary, Italy, Turkey and Central Europe with the SEE region under the SM, PMC and FMC scenarios in Figure 57 to Figure 60. The values in the arrows show the exchange direction – blue arrows are exports from the SEE region to neighboring market areas, and red arrows show imports to the SEE region from neighboring areas.

In all scenarios, the SEE region exports more electricity to neighboring areas than it imports, and market integration increases net exports. The neighboring market areas import 25,708 GWh in the SM scenario, 26,324 GWh in the PMC scenario, and 27,758 GWh in the FMC scenario from the SEE region. At the same time, they export 22,104 GWh in the SM scenario, 22,553 GWh in the PMC scenario, and 21,945 GWh in the FMC scenario to the SEE region.

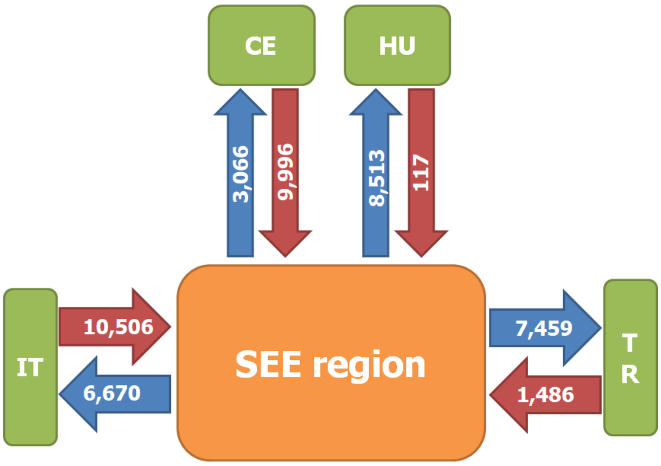


Figure 57: Hungary, Italy, Turkey, Central Europe and SEE region exchange in 2025 (Dry hydrological conditions – SM)

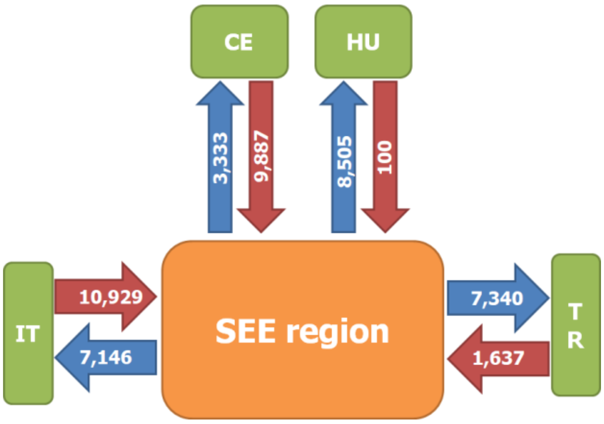


Figure 58: Hungary, Italy, Turkey, Central Europe and SEE region exchange in 2025 (Dry hydrological conditions – PMC)

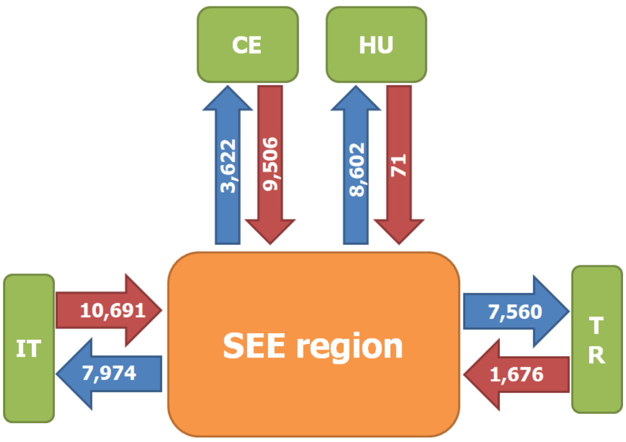


Figure 59: Hungary, Italy, Turkey, Central Europe and SEE region exchange in 2025 (Dry hydrological conditions - FMC)

We compare yearly net interchange values for the different market coupling scenarios in Figure 38. In this comparison, we note that market integration leads to lower imports from CE, and more exports to HU. Import from Italy, and exports to Turkey both fall. As previously mentioned, market integration unlocks the potential for additional generation and the exchange of lower cost electricity, and thus decreases imports from neighboring regions (such as CE), while increasing exports to other neighboring regions (such as Hungary).

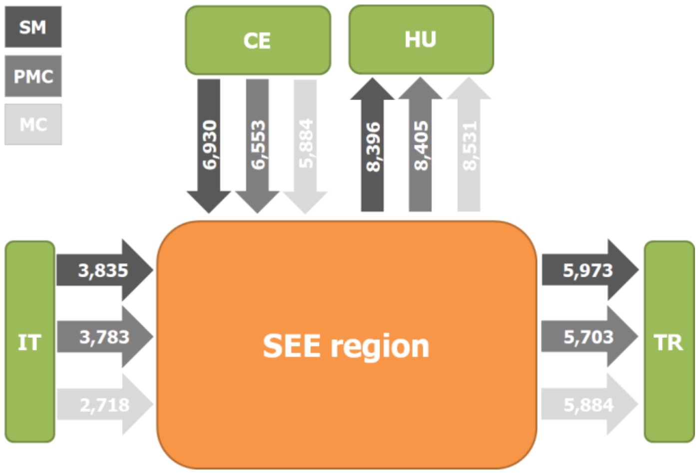


Figure 60: Hungary, Italy, Turkey, Central Europe and SEE region net interchange in 2025 (Dry hydrological conditions – comparison of the coupling scenarios)

In the market model, the marginal cost of generation determines the wholesale market price, and we present our forecast of wholesale prices by market area in Table 65. The average wholesale market price in the SEE region is the load-weighted average values for all market areas, and is 58.70 €/MWh in the SM scenario, 58.04 €/MWh in the PMC scenario, and 57.40 €/MWh in the FMC scenario. Thus, the average SEE market price in the PMC scenario is 0.66 €/MWh (1.12%) lower than in SM scenario, while in the FMC scenario it is 1.30 €/MWh (2.21%) lower.

In most exporting countries in SEE, average market prices rise with market integration, while in importing markets, they fall. This is expected since coupling enables higher exchanges of low cost energy and harmonizes prices. With no cross-border constraints, all prices would be equal.

By analyzing Table 65, together with changes in net interchange (Table 64), we can observe the interdependence between increases in exports/imports, and the increase/decrease of prices. This is a logical consequence of market integration, since with market coupling, exporting countries (with lower prices) gain opportunities to export more electricity to importing countries (with higher prices). Under this convergence, prices in lower cost market areas rise, while they fall in higher cost areas.

For example, ADMIE/IPTO, a large importer, has a substantial price decrease, by 5.78 €/MWh in the PMC and 7.49 €/MWh in the FMC scenario, compared to the SM scenario. This indicates that ADMIE/IPTO market area may expect larger benefits from coupling than other areas.

By contrast, the ESO EAD market area may show a price rise of 0.73 €/MWh in the PMC, and 1.44 €/MWh in the FMC, compared with the SM scenario. We expect that that price differences between the ADMIE/IPTO and ESO EAD areas would decrease from 15.65 €/MWh to 9.13 €/MWh and 6.72 €/MWh through different levels of market coupling. This may also lead to a reduction in congestion rents to TSOs on these borders.

We show that there will be price convergence for the entire region in the last column of Table 65, which also shows the coefficient of variation (CV) of prices. As market integration increases, this CV falls, showing that prices become less dispersed.

Looking at the SEE level, average prices decrease with stronger coupling of the market areas. This may seem counter-intuitive, since the region exports more as coupling grows. The reason for this result lies in the fact that average regional prices are calculated as load-weighted averages. Since there is a significant price decrease (of 6 or 7.5 €/MWh) in a large market area (ADMIE/IPTO) and, at the same time, a small price increase (just for 2 or 3 €/MWh) in another large market area (TransElectrica), the average price values decrease as market coupling grows.

Table 65: Comparison of average wholesale prices by market area in 2025 (Dry hydrological conditions)

Price (€/MWh)	AL	BA	BG	GR	HR	ME	MK	RO	RS	SI	XK	SEE	CV
Separated markets	58.51	56.00	53.92	69.57	59.03	56.32	56.97	54.00	55.29	57.42	57.08	**58.70**	**7.07%**
Partial market coupling	60.01	57.59	54.65	63.78	58.77	57.44	58.04	54.66	56.87	57.09	59.08	**58.04**	**4.17%**
Change (€/MWh)	1.50	1.59	0.73	-5.78	-0.26	1.13	1.07	0.66	1.58	-0.32	2.00	**-0.66**	
Change (%)	2.57	2.84	1.35	-8.32	-0.44	2.00	1.88	1.22	2.85	-0.56	3.51	**-1.12**	
Full market coupling	56.62	56.27	55.36	62.08	58.60	56.04	55.64	55.46	55.71	56.80	56.04	**57.40**	**3.32%**
Change (€/MWh)	-1.88	0.27	1.44	-7.49	-0.43	-0.28	-1.33	1.46	0.42	-0.62	-1.03	**-1.30**	
Change (%)	-3.22	0.47	2.67	-10.76	-0.73	-0.50	-2.34	2.71	0.76	-1.07	-1.81	**-2.21**	

We compare average wholesale prices in different scenarios in Figure 82.

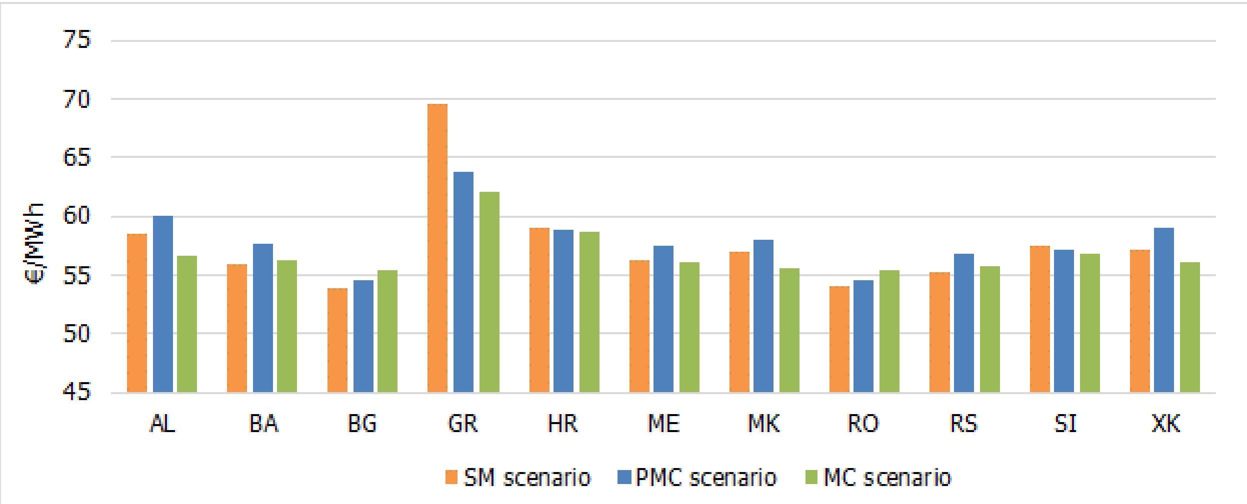


Figure 61: Comparison of average wholesale prices in 2025 (Dry hydrological conditions)

After analyzing different market parameters, we calculate the change in social-economic welfare (SEW) to fully evaluate the overall benefits of SEE market integration.

According to the ENTSO-E definition, SEW is measured through the change in total surplus (the sum of consumer surplus, producer surplus and congestion rents). Below, we show the SEW for the PMC and FMC scenarios compared to the SM scenario, as in Chapter 4.1.5.

We present the socio-economic welfare (SEW) under different market integration options for the baseline scenario in the following table.

Table 66: Comparison of socio-economic welfare in 2025 (Dry hydrology scenario)

Market area	Partial market coupling - Separated markets				Full market coupling - Separated markets			
million €	Δ Producer surplus	Δ Consumer surplus	Δ Congestion rent	Δ Total surplus	Δ Producer surplus	Δ Consumer surplus	Δ Congestion rent	Δ Total surplus
AL	11.41	-12.68	-2.35	**-3.62**	-4.15	15.89	-5.55	**6.19**
BA	30.98	-21.12	-4.78	**5.07**	6.63	-3.53	-0.06	**3.04**
BG	39.06	-25.52	-29.41	**-15.87**	79.82	-50.50	-53.40	**-24.07**
GR	-269.39	363.48	-61.55	**32.54**	-345.29	469.18	-72.01	**51.87**
HR	-6.21	5.44	-6.19	**-6.96**	-10.51	9.01	3.06	**1.56**
ME	7.50	-5.38	-0.37	**1.75**	-0.30	1.34	-3.59	**-2.56**
MK	8.12	-9.53	-0.55	**-1.96**	-7.20	11.87	-7.06	**-2.40**
RO	44.40	-39.83	-2.42	**2.15**	100.68	-88.64	-11.04	**1.00**
RS	62.61	-58.21	0.43	**4.83**	22.70	-15.53	-4.86	**2.30**
SI	-4.35	4.81	4.07	**4.53**	-8.59	9.15	8.88	**9.44**
XK	16.41	-12.70	1.10	**4.81**	-7.05	6.57	-5.02	**-5.51**
TOTAL SEE	**-59.46**	**188.76**	**-102.02**	**27.28**	**-173.26**	**364.80**	**-150.67**	**40.86**

This table shows partial market coupling in the SEE region can provide benefits of 27 million EUR which would increase with full market coupling to 40 million EUR. There are areas with positive and negative change in SEW, which are not a negative signal for market coupling.

The largest benefits can be expected in the ADMIE/IPTO market area due to adequacy problems cy (and the existence of Energy Not Supplied), which stronger coupling can significantly reduce. Stronger coupling significantly reduces prices in the ADMIE/IPTO market, which leads to a large increase in consumer surplus. Also, coupling reduces congestion on the borders with ESO EAD market area and reduces their price difference, bringing lower congestion rents to the TSOs.

In almost all market areas, market coupling leads to a decrease in congestion rents, as expected, since more cross-border capacity become available for transactions with greater market coupling. In some cases, like ESO EAD, CGES, KOSTT and MEPSO market areas, the decrease in congestion rents leads to a negative SEW.

Only market areas that are positioned between two distinctive price groups (like ELES, and partially KOSTT, EMS and HOPS) have benefits from increased congestion rents, due to market coupling. In all other market areas, price convergence plus more cross-border capacity leads to lower congestion rents for TSOs.

On the other hand, almost all market areas benefit from market coupling when we sum producer and consumer surpluses. In exporting market areas, benefits are more on the producers' side, while in importing ones, on the consumers' side, due to higher/lower prices, respectively. We present the sum of changes in producer and consumer surpluses in Table 67. In almost all market areas this sum is positive, showing benefits from market coupling for producers and consumers. For the region as a whole, the sum of producer and consumer surplus is highly positive (129 to 191 million Euros).

Table 67: Comparison of the sum of changes in producer and consumer surpluses in 2025 (Dry hydrology scenario)

Market area	Partial market coupling - Separated markets			Full market coupling - Separated markets		
million €	Δ Producer surplus	Δ Consumer surplus	Sum	Δ Producer surplus	Δ Consumer surplus	Sum
AL	11.41	-12.68	**-1.26**	-4.15	15.89	**11.74**
BA	30.98	-21.12	**9.86**	6.63	-3.53	**3.10**
BG	39.06	-25.52	**13.54**	79.82	-50.50	**29.33**
GR	-269.39	363.48	**94.10**	-345.29	469.18	**123.89**
HR	-6.21	5.44	**-0.78**	-10.51	9.01	**-1.49**
ME	7.50	-5.38	**2.11**	-0.30	1.34	**1.03**
MK	8.12	-9.53	**-1.41**	-7.20	11.87	**4.66**
RO	44.40	-39.83	**4.57**	100.68	-88.64	**12.04**
RS	62.61	-58.21	**4.40**	22.70	-15.53	**7.16**
SI	-4.35	4.81	**0.46**	-8.59	9.15	**0.56**
XK	16.41	-12.70	**3.71**	-7.05	6.57	**-0.48**
TOTAL SEE	**-59.46**	**188.76**	**129.30**	**-173.26**	**364.80**	**191.54**

There are a few exceptions to this overall conclusion. In case of the HOPS market area, coupling with the NOSBiH market area reduces prices, but still keeps a high level of internal generation, so the increase of consumer surplus is more than offset by a somewhat larger decrease in producer surplus. In the MEPSO market area, coupling with ESO EAD and with the ADMIE/IPTO market areas increases prices and, since it is an importing area, the increase in producer surplus is lower than the decrease in consumer surplus.

In FMC, further coupling of the HOPS and EMS market areas leads to a further price decrease from the PMC case. This decreases producer surplus (- 4.3 million EUR) and increases consumer surplus (+ 3.57 million EUR), but the small change in prices is not enough to show a positive sum for producer and consumer surplus. In the KOSTT market area, coupling at all borders decreases prices and, since it is an exporting area, the decrease in producer surplus is bigger than the increase in consumer surplus, leading to a negative sum of consumer and producer surpluses.

4.3 Set of scenarios with high level of RES penetration and low demand

4.3.1 Separated (non-coupled) markets (SM)

We depict electricity generation and consumption in the SEE region in the SM scenario under a high level of RES penetration and low demand in Figure 62. Total generation in the SEE region in 2025 would reach 277.89 TWh, while total consumption would be 259.15 TWh. The highest generation would be in the TransElectrica area, and the CGES area would have the lowest generation.

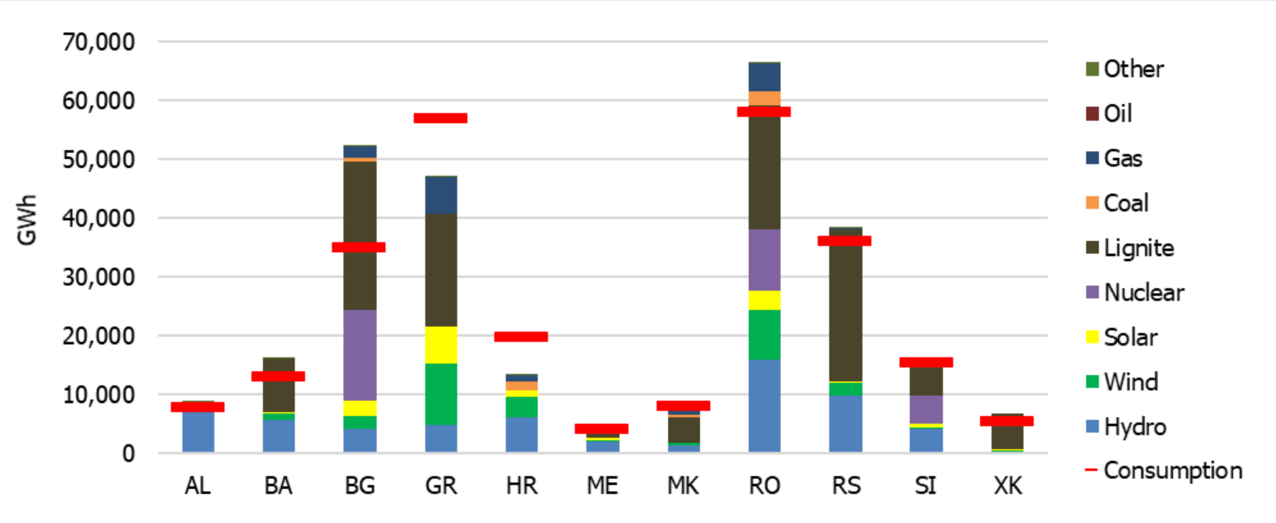


Figure 62: Electricity generation mix and consumption by market area in 2025 (High RES and low demand – SM)

We present the electricity generation mix by market area in more detail in the following table.

Table 68: Electricity generation mix by market area in 2025 (High RES and low demand – SM)

Yearly generation (TWh)	AL	BA	BG	GR	HR	ME	MK	RO	RS	SI	XK	SEE
HPP	8.40	5.80	4.37	5.18	6.45	1.93	1.47	15.89	10.00	4.85	0.17	**64.49**
TPP lignite	0.00	9.10	25.17	19.19	0.00	1.49	4.38	20.93	25.92	5.10	6.04	**117.33**
TPP coal	0.00	0.00	0.72	0.00	1.65	0.00	0.36	2.42	0.00	0.00	0.00	**5.14**
TPP gas	0.00	0.00	2.00	6.29	1.05	0.00	0.57	4.85	0.16	0.38	0.00	**15.30**
TPP oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	**0.00**
TPP other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.52	0.00	0.00	0.00	**0.52**
Nuclear	0.00	0.00	15.42	0.00	0.00	0.00	0.00	10.44	0.00	4.90	0.00	**30.76**
Solar	0.11	0.14	2.51	6.28	1.12	0.41	0.09	3.36	0.26	0.62	0.14	**15.03**
Wind	0.27	1.13	2.21	10.40	3.40	0.42	0.27	8.48	2.17	0.16	0.40	**29.31**
TOTAL	**8.78**	**16.16**	**52.40**	**47.34**	**13.66**	**4.25**	**7.15**	**66.89**	**38.49**	**16.02**	**6.75**	**277.89**

In most of the SEE market areas, TPPs have the highest share, except in the OST, HOPS and CGES market areas, where HPPs have the highest share, and except in the TransElectrica and ELES market areas, where nuclear electricity generation has a high share. The least diversified generation mix is the KOSTT market area, where 90% of electricity generation comes from TPPs.

We show the electricity balances (i.e., yearly consumption, generation and exchange values) for each SEE market area in the SM scenario in Table 69. The ESO EAD and TransElectrica market areas have the highest net interchange value, meaning they are the main net exporters in the SEE region, while the ADMIE/IPTO market area is a significant net importer. The total sum of net interchange in the SEE region is not zero, since this model includes neighboring power systems (i.e., three external markets and Hungary) modelled on a technology level.

Table 69: Electricity balance in 2025 (High RES and low demand – SM)

Electricity balance	Cons. (GWh)	Gener. (GWh)	Pump load (GWh)	Custom. load (GWh)	Imports (GWh)	Exports (GWh)	Transit (GWh)	Net inter-change (GWh)	Net import / export share (%)
AL	7,730	8,781	0	7,730	1,178	2,229	565	1,051	13.59%
BA	12,944	16,159	108	12,835	394	3,609	905	3,216	24.84%
BG	35,017	52,403	256	34,760	0	17,386	2808	17,386	49.65%
GR	56,804	47,343	349	56,456	9,623	162	4964	-9,461	-16.66%
HR	19,794	13,661	394	19,400	6,576	443	2366	-6,133	-30.98%
ME	4,033	4,252	0	4,033	726	945	3314	219	5.43%
MK	7,988	7,149	0	7,988	1,019	179	2315	-840	-10.51%
RO	58,028	66,873	0	58,028	71	8,915	1761	8,844	15.24%
RS	36,071	38,488	275	35,795	447	2,864	3052	2,417	6.70%
SI	15,289	16,021	886	14,403	681	1,413	12149	732	4.79%
XK	5,449	6,749	0	5,449	325	1,624	724	1,299	23.84%
SEE	**259,147**	**277,877**	**2,269**	**256,879**	**21,039**	**39,769**	**34,923**	**18,730**	**7.23%**

Consumption presented in the table above refers to the total consumption calculated by adding the customer load (demand) and pump load for pumped storage HPPs, and subtracting the energy not supplied (if it exists). Customer load is a predefined hourly input time series of demand. Pumped load values change in scenarios based on the operation of pumped storage HPPs in pumping mode. Generation presented in the table refers to the total generation calculated by adding the generation of all modelled power plants, and subtracting the curtailed generation (if it exists).

We previously showed the yearly values for electricity exchange of SEE market areas in Table 69, and here we also present the neighboring power systems. We depict exports and imports values in Figure 63, transits in Figure 64, and net interchange in Figure 65. In the SEE region, the ADMIE/IPTO market area is the highest net importer, and the ESO EAD market area is the highest net exporter, as shown in Figure 65. Figure 64 shows that the highest power transit is through the ELES market area, due to borders with high importing market areas (such as the ELES and Hungarian market areas), high exporting market areas (such as CE), and significant energy exchange with the Italian market in both directions. This is consistent with the border flows presented later in Table 71. In neighboring power systems, the highest power transits are through Hungary. While Hungary, Italy and Turkey mostly import electricity from the SEE region, Central Europe mostly exports electricity to the SEE region. This is expected considering the lower level of wholesale market price in Central Europe compared to the other neighboring markets (as presented in Chapter 2.5).

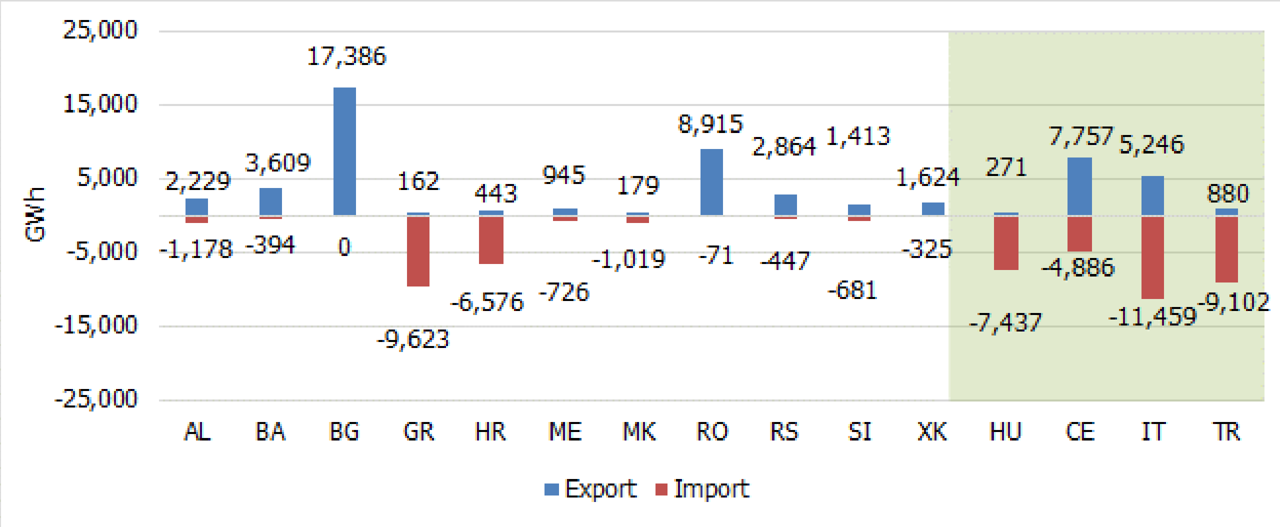


Figure 63: Imports and exports in 2025 (High RES and low demand – SM)

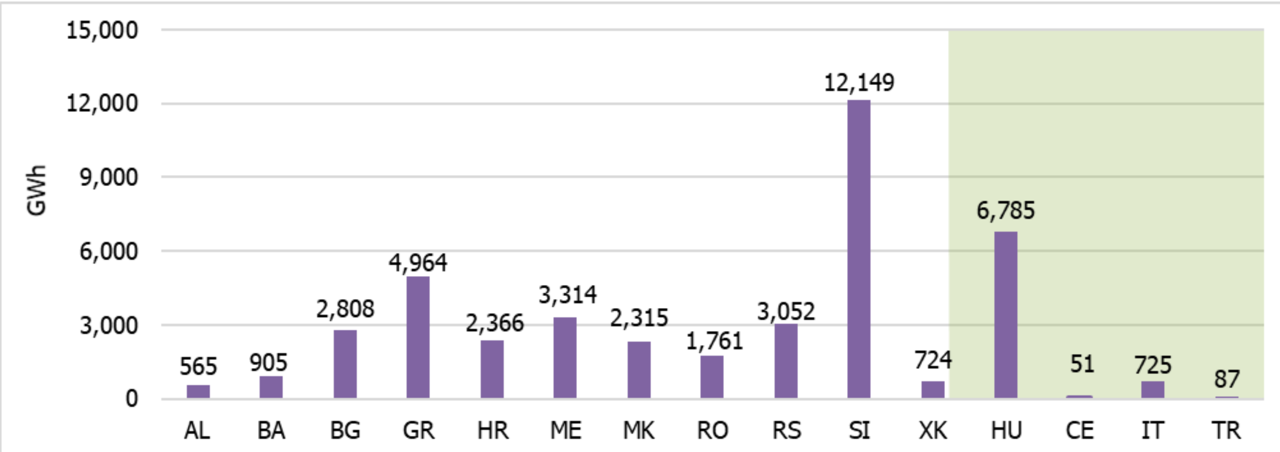


Figure 64: Transits in 2025 (High RES and low demand – SM)

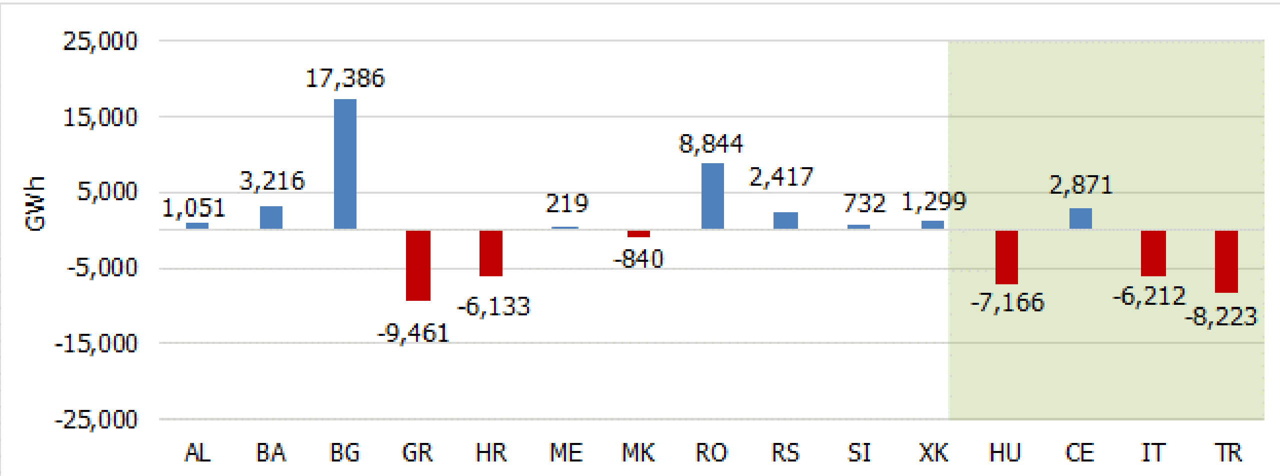


Figure 65: Net interchange in 2025 (High RES and low demand – SM)

When observing differences among the SEE market areas, the important factor is operating cost, for which yearly simulation results are presented in Table 70. The market price is determined by marginal cost of generation, and by price in neighboring markets, and calculation of operating costs is based on variable costs, including the fuel, CO_2 and O&M costs of generating units.

In the SM scenario, average operating costs in the SEE region amount to 11.39 €/MWh. The highest average operating cost is in the ESO EAD market area (14.16 €/MWh) where TPPs have a high share. Table 70 also presents data about yearly CO_2 emissions in the SEE region. The highest level of CO_2 emissions is in the EMS market area. Average total operating costs, which include carbon costs, amount to 23.39 €/MWh in the SEE region. In terms of average operating cost, the KOSTT market area has the highest value (35.41 €/MWh) followed by the MEPSO market area (32.20 €/MWh). This is due to the carbon cost, which mostly affects market areas with high shares of coal-based TPPs.

In this scenario, the average SEE regional wholesale market price is 50.04 €/MWh. Generally, regional wholesale electricity prices are harmonized, but there are certain variations. The HOPS, ELES and ADMIE/IPTO market areas have somewhat higher average wholesale prices than the rest of the modelled region. The highest average price is in the HOPS market area (54.97 €/MWh), while the lowest is in the TransElectrica market area (48.01 €/MWh).

Table 70: Operating costs in 2025 (High RES and low demand – SM)

Operating costs without and with emissions costs	AL	BA	BG	GR	HR	ME	MK	RO	RS	SI	XK	SEE
Operating costs (mil. €)	0	143	742	591	102	23	98	843	380	158	85	**3,164**
CO_2 emissions (mil. tonne)	0	11	25	21	2	1	5	26	27	5	6	**130**
CO_2 emissions costs (mil. €)	0	293	633	535	52	38	132	676	694	129	154	**3,336**
Total operating costs (mil. €)	0	435	1,375	1,126	154	61	230	1,519	1,074	286	239	**6,500**
Average operating costs (€/MWh)	0.00	8.82	14.16	12.48	7.45	5.37	13.74	12.61	9.87	9.84	12.54	**11.39**
Average total operating costs (€/MWh)	0.00	26.94	26.24	23.79	11.26	14.30	32.20	22.71	27.90	17.88	35.41	**23.39**
Price (€/MWh)	49.37	49.47	48.14	51.93	54.97	49.44	48.88	48.01	48.41	54.59	48.80	**50.04**

We analyze yearly cross-border exchange, loading and congestions results below.

The ELES market area has the highest cross-border exchange (Table 71), i.e., 26,391 GWh (13,562 GWh of total exports, including transits, from the ELES market area to neighboring market areas, and 12,830 GWh of total imports, including transits, in the opposite direction). The KOSTT market area has the lowest yearly cross-border exchange in the SEE region, which amounts to 3,396 GWh (2,348 GWh of total exports, including transits, from the KOSTT market area to neighboring market areas, and 1,048 GWh of total imports, including transits, in the opposite direction). When analyzing individual flows per border, we note the highest yearly flow on the BG-GR border, from the ESO EAD market area to the ADMIE/IPTO market area, showing that imports to the ADMIE/IPTO market area mostly come from the ESO EAD market area.

Table 71: Cross-border exchange in 2025 (High RES and low demand – SM)

Market area	Flow (GWh)														
	AL	BA	BG	GR	HR	HU	ME	MK	RO	RS	SI	XK	CE	IT	TR
AL	-			602			1,054	610				528			
BA		-			3,351		810			354					
BG			-	10,247				1,377	1,386	635					6,549
GR	88		0	-				117						2,281	2,640
HR		163			-	467				31	2,147				
HU					1,753	-			256	122	2,622		2,304		
ME	465	369					-			134		178		3,112	
MK	372		43	1,992				-		59		28			
RO			2,107			6,768			-	1,800					
RS		766	237		1,585	1,680	493	651	190	-		315			
SI					2,253	1,885					-		2,633	6,791	
XK	819						587	579		363		-			
CE						3,422					4,386		-		
IT				1,200			1,096				3,675			-	
TR			421	546											-

The yearly average cross-border loadings are given in Table 72. Cells in red have high flows (above 50%), while cells in green have low flows (below 10%). In this scenario, the highest loading values occur on the BG-GR border (87%, towards the ADMIE/IPTO market area), which is consistent with the high flows presented in Table 71. High loadings also occur on BG-TR border (83%, towards Turkey). Generally, almost all links to the ADMIE/IPTO market area and Turkey are highly loaded. The TransElectrica market area's cross-border lines have notably low loading values in the direction of the TransElectrica market area (3-13%), while they are significantly higher in the opposite direction (22-70%), confirming this area as an exporter of electricity.

Table 72: Cross-border loading in 2025 (High RES and low demand – SM)

Market area	Loading (%)														
	AL	BA	BG	GR	HR	HU	ME	MK	RO	RS	SI	XK	CE	IT	TR
AL	-			55			48	35				19			
BA		-			68		31			13					
BG			-	87				63	13	36					83
GR	8		0	-				3						52	76
HR		4			-	5				1	20				
HU					17	-			3	5	25		33		
ME	21	14					-			10		14		59	
MK	14		2	55				-		7		3			
RO			22			70			-	41					
RS		29	14		73	64	38	46	5	-		24			
SI					20	18					-		32	49	
XK	30						45	41		21		-	0		
CE						49					53		-		
IT				27			21				25			-	
TR			10	14											-

We depict the cross-border loadings in both directions (i.e., the sum of loadings in the reference and counter-reference directions) in the following figure. The blue bars present borders that are coupled in all scenarios, while the orange bars show borders that are coupled only in the PMC and FMC scenarios. Thus, in this SM scenario, the borders shown in orange are not coupled.

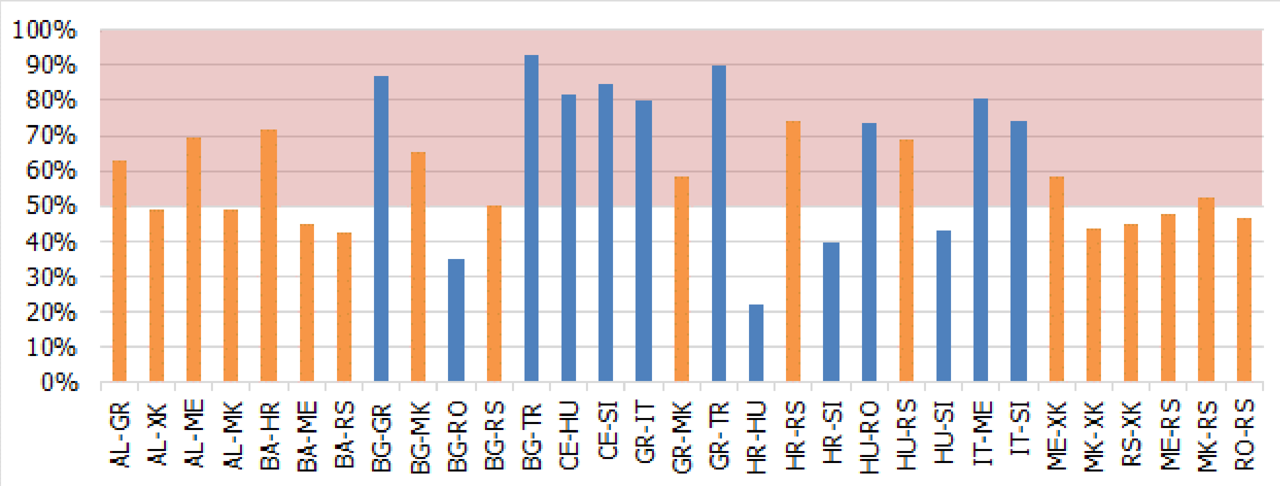


Figure 66: Cross-border loadings in both directions in 2025 (High RES and low demand – SM)

As Figure 66 shows, cross-border loadings in both directions range from 22% to 93%. When analyzing borders on which we expect couplings, we note high loadings (above 50%) in both directions on the AL-GR, AL-ME, BA-HR, BG-MK, GR-MK, HR-RS, HU-RS, ME-XK and MK-RS borders.

Cross-border congestions represent the number of annual hours when flow on interconnections equals or exceeds the modelled NTC. We present the cross-border congestion probability on each border in Table 73. Cells in red have high congestion probability (i.e., above 50%), while cells in green have low congestion probability (i.e., below 10%). We note significant congestion probabilities, especially on the BG-TR and GR-TR borders, but only in one direction – towards the Turkish electricity market. Other borders with high congestion probabilities are the BG-GR border (towards the ADMIE/IPTO market area) and the RS-HR border (towards the HOPS market area).

Table 73: Cross-border congestion probability in 2025 (High RES and low demand – SM)

Market area	Congestion probability (%)														
	AL	**BA**	**BG**	**GR**	**HR**	**HU**	**ME**	**MK**	**RO**	**RS**	**SI**	**XK**	**CE**	**IT**	**TR**
AL	-			53			43	32				12			
BA		-			57		22			11					
BG			-	74				54	5	34					82
GR	8		0	-				2						52	75
HR		2			-	1				1	5				
HU					2	-			1	4	5		31		
ME	18	9					-			8		11		57	
MK	7		2	45				-		8		4			
RO			10			64			-	32					
RS		26	12		70	61	36	40	4	-		22			
SI					14	10					-		30	44	
XK	18						39	29		16		-	0		
CE						47					49		-		
IT				27			19				19			-	
TR			10	15											-

4.3.2 Partial market coupling (PMC)

We depict electricity generation and consumption in the SEE region for the PMC scenario with high levels of RES penetration and low demand in Figure 67. Total generation in the SEE region in 2025 would reach 280.63 TWh, and consumption 259.26 TWh. As in other scenarios, the highest generation is in the TransElectrica market area, and the lowest in the CGES market area.

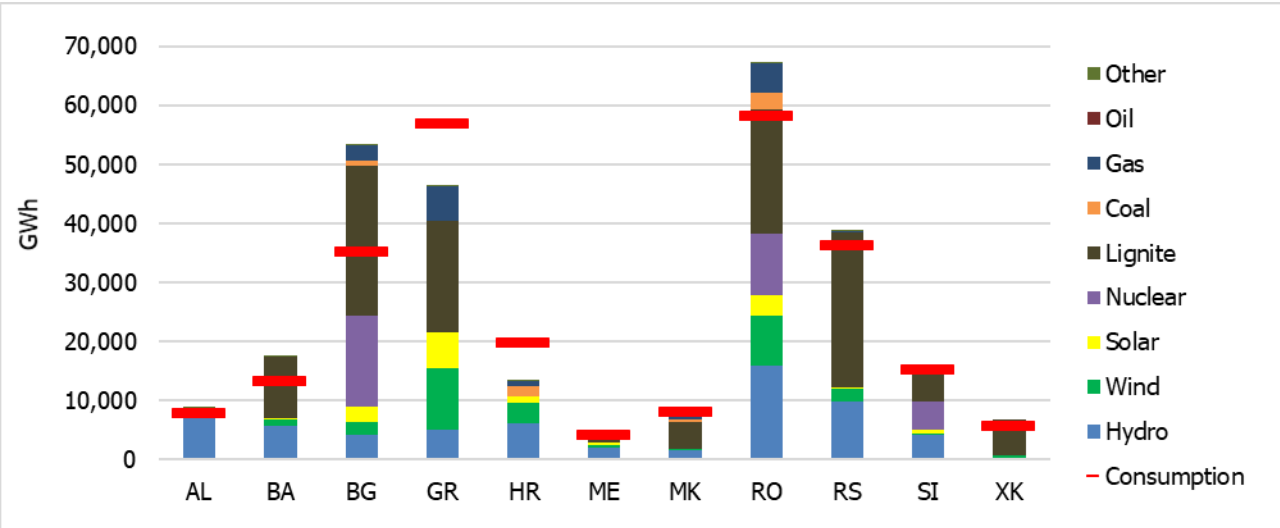


Figure 67: Electricity generation mix and consumption by market area in 2025 (High RES and low demand – PMC)

We present the electricity generation mix by market area in more detail in the following table.

Table 74: Electricity generation mix by market area in 2025 (High RES and low demand – PMC)

Yearly generation (TWh)	AL	BA	BG	GR	HR	ME	MK	RO	RS	SI	XK	SEE
HPP	8.40	5.89	4.41	5.15	6.40	1.93	1.47	15.89	10.09	4.78	0.17	**64.58**
TPP lignite	0.00	10.40	25.46	18.89	0.00	1.49	4.44	21.15	26.26	5.10	6.09	**119.28**
TPP coal	0.00	0.00	0.88	0.00	1.62	0.00	0.45	2.68	0.00	0.00	0.00	**5.63**
TPP gas	0.00	0.00	2.48	5.75	0.86	0.00	0.64	5.05	0.25	0.36	0.00	**15.39**
TPP oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	**0.00**
TPP other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.65	0.00	0.00	0.00	**0.65**
Nuclear	0.00	0.00	15.42	0.00	0.00	0.00	0.00	10.44	0.00	4.90	0.00	**30.76**
Solar	0.11	0.14	2.51	6.28	1.12	0.41	0.09	3.36	0.26	0.62	0.14	**15.03**
Wind	0.27	1.13	2.21	10.40	3.40	0.42	0.27	8.48	2.17	0.16	0.40	**29.31**
TOTAL	**8.78**	**17.55**	**53.37**	**46.47**	**13.40**	**4.25**	**7.36**	**67.69**	**39.03**	**15.93**	**6.79**	**280.63**

In most of the SEE market areas, TPPs have the highest share, except in the OST, HOPS and CGES market areas, where HPPs have the highest share, and in the TransElectrica and ELES market areas, where nuclear generation has a high share. The least diversified generation mix is the KOSTT market area, with 90% of electricity generation from TPPs.

We show the expected electricity balances (i.e., yearly consumption, generation and exchange values) for each of the SEE market areas in the PMC scenario in Table 75. The ESO EAD and TransElectrica market areas have the highest net interchange value, meaning they are the main net exporters in the SEE region, while the ADMIE/IPTO market area is a significant net importer. The sum of net interchange in the SEE region is not zero, since this model includes neighboring power systems (i.e., three external markets and Hungary) modelled on a technology level.

Table 75: Electricity balance in 2025 (High RES and low demand – PMC)

Electricity balance	Cons. (GWh)	Gener. (GWh)	Pump load (GWh)	Custom. load (GWh)	Imports (GWh)	Exports (GWh)	Transit (GWh)	Net inter-change (GWh)	Net import / export share (%)
AL	7,730	8,781	0	7,730	1,286	2,337	616	1,051	13.59%
BA	13,067	17,549	232	12,835	262	4,743	1373	4,481	34.30%
BG	35,063	53,373	303	34,760	0	18,310	3154	18,309	52.22%
GR	56,764	46,469	308	56,456	10,465	170	5112	-10,295	-18.14%
HR	19,740	13,400	340	19,400	6,596	256	4045	-6,340	-32.12%
ME	4,033	4,253	0	4,033	796	1,016	3452	220	5.46%
MK	7,988	7,363	0	7,988	937	312	3643	-625	-7.83%
RO	58,028	67,679	0	58,028	61	9,712	1588	9,651	16.63%
RS	36,198	39,026	403	35,795	413	3,240	4034	2,827	7.81%
SI	15,198	15,925	795	14,403	661	1,389	13019	728	4.79%
XK	5,449	6,794	0	5,449	317	1,661	994	1,344	24.66%
SEE	**259,260**	**280,612**	**2,381**	**256,879**	**21,793**	**43,144**	**41,029**	**21,352**	**8.24%**

Consumption in the table above refers to the total consumption calculated by adding the customer load (demand) and pump load for pumped storage HPPs, and subtracting the energy not supplied (if it exists). Customer load is a predefined hourly input time series of demand. Pumped load values change in the scenarios based on the operation of pumped storage HPPs in pumping mode.

Generation presented in the table refers to total generation calculated by adding the generation of all modelled power plants, and subtracting curtailed generation (if it exists).

We showed yearly values for exports, imports, transits and net interchange for the SEE market areas in Table 75, but here also for neighboring power systems. Exports and imports values are depicted in Figure 68, transits in Figure 69 and net interchanges in Figure 70. Exports are positive values, while imports are negative. In the SEE region, the ADMIE/IPTO market area is the highest net importer and the ESO EAD market area is the highest net exporter, as shown in Figure 70. Figure 69 shows that highest power transit is through the ELES market area, as in the SM scenario. Regarding neighboring power systems, the highest power transits are through Hungary.

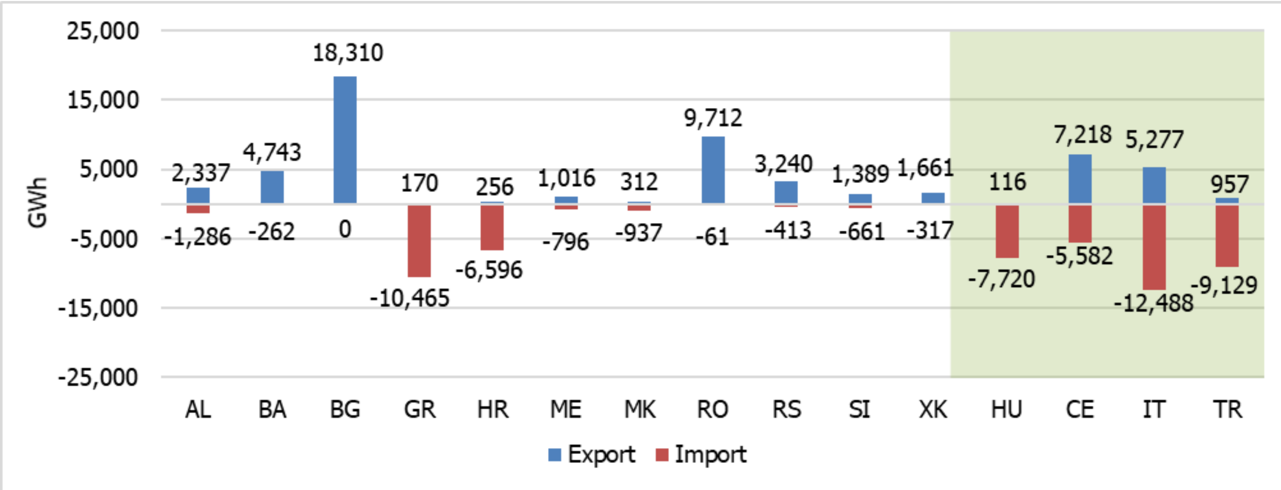


Figure 68: Imports and exports in 2025 (High RES and low demand – PMC)

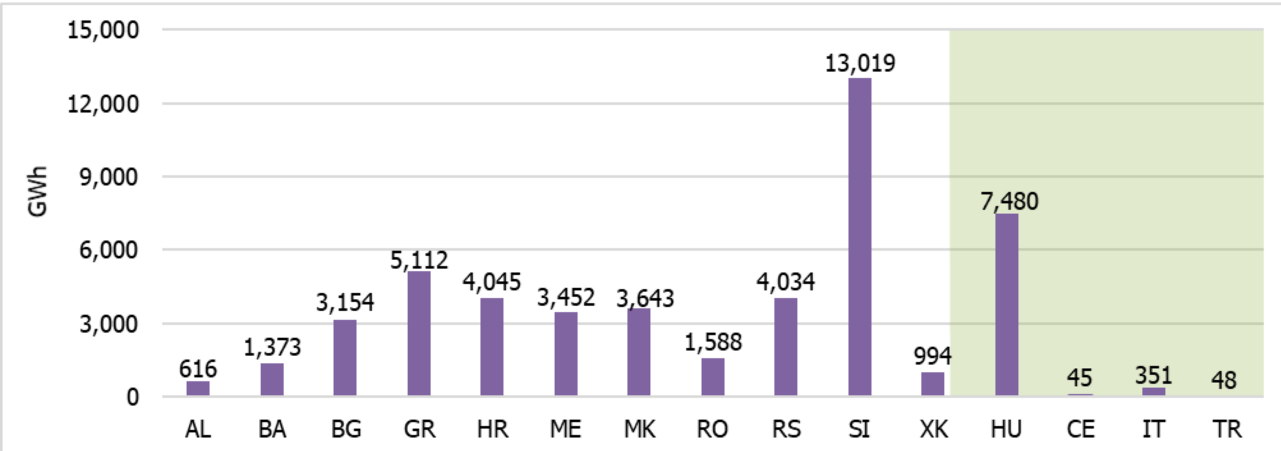


Figure 69: Transits in 2025 (High RES and low demand – PMC)

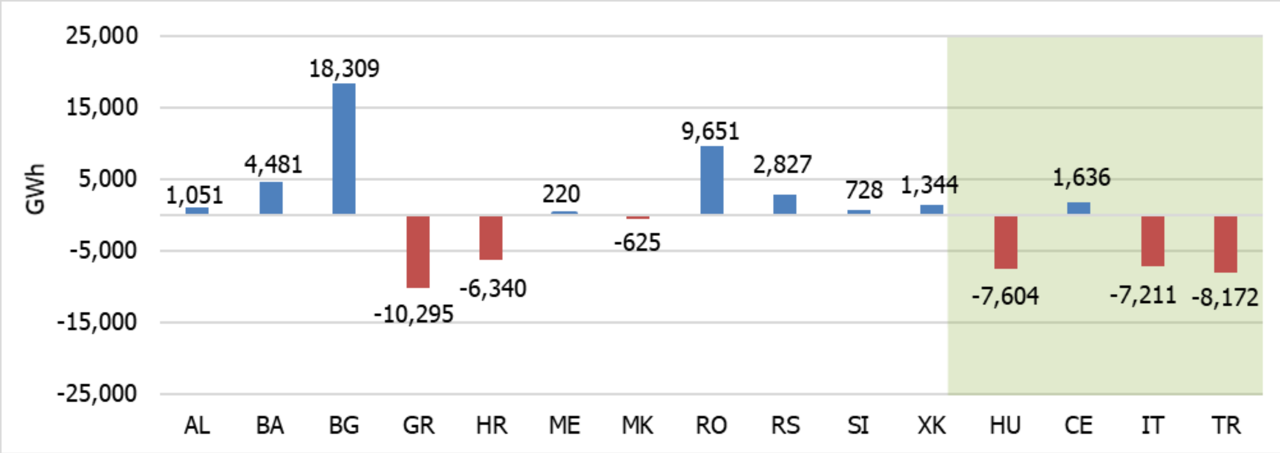


Figure 70: Net interchange in 2025 (High RES and low demand – PMC)

When there are differences among the SEE market areas, the important factor is operating cost, for which we present early simulation results in Table 76. Market price is determined by marginal cost of generation and price on neighboring markets, and calculation of operating costs themselves is based on variable cost including fuel, CO_2 and O&M cost of generating units.

Average regional operating costs in this scenario would be 11.46 €/MWh, with the highest cost in the ESO EAD market area (14.51 €/MWh), with substantial TPPs. Table 76 also presents data on yearly regional CO_2 emissions. The highest CO_2 emissions would be in the EMS market area. Average regional operating costs, including carbon, amount to 23.60 €/MWh. In terms of average total operating cost, the KOSTT market area is highest (35.46 €/MWh), followed by MEPSO (32.68 €/MWh), due to carbon cost, which mostly affects those with a high share of coal TPPs.

In this scenario, the average SEE regional wholesale market price is 50.41 €/MWh. Generally, wholesale electricity prices are harmonized in the region, more than in the SM scenario, but there are still variations. The HOPS and ELES market areas would have somewhat higher average wholesale prices than the rest of the SEE region. The highest average price is in the HOPS market area (53.90 €/MWh), while the lowest is in the TransElectrica market area (48.89 €/MWh).

Table 76: Operating costs in 2025 (High RES and low demand – PMC)

Operating costs without and with emissions costs	AL	BA	BG	GR	HR	ME	MK	RO	RS	SI	XK	SEE
Operating costs (mil. €)	0	164	774	560	90	23	105	870	390	156	85	**3,217**
CO_2 emissions (mil. tonne)	0	13	25	20	2	1	5	27	27	5	6	**133**
CO_2 emissions costs (mil. €)	0	335	648	522	50	38	136	690	704	128	156	**3,407**
Total operating costs (mil. €)	0	498	1,423	1,081	140	61	241	1,560	1,094	285	241	**6,623**
Average operating costs (€/MWh)	0.00	9.32	14.51	12.05	6.75	5.37	14.20	12.85	9.98	9.81	12.56	**11.46**
Average total operating costs (€/MWh)	0.00	28.40	26.66	23.27	10.45	14.31	32.68	23.05	28.03	17.88	35.46	**23.60**
Price (€/MWh)	50.15	51.09	49.10	50.96	53.90	50.66	49.60	48.89	50.06	53.56	49.75	**50.41**

We analyze yearly cross-border exchange, loading and congestions results below.

The ELES market area has the highest cross-border exchange (Table 77) (i.e., 28,087 GWh (14,407 GWh of total exports to neighboring market areas and 13,679 GWh of total imports in the opposite direction). The KOSTT market area has the lowest yearly cross-border exchange in the SEE region (3,967 GWh , with 2,655 GWh of total exports to neighboring market areas, and 1,311 GWh of total imports in the opposite direction). When analyzing individual border flows, we note the highest yearly flow on BG-GR border, from the ESO EAD market area to the ADMIE/IPTO market area, as in the case of SM scenario.

Table 77: Cross-border exchange in 2025 (High RES and low demand – PMC)

Market area	Flow (GWh)														
	AL	**BA**	**BG**	**GR**	**HR**	**HU**	**ME**	**MK**	**RO**	**RS**	**SI**	**XK**	**CE**	**IT**	**TR**
AL	-			538			1,103	569				743			
BA		-			5,562		433			122					
BG			-	10,075				2,892	1,249	779					6,468
GR	96		0	-				77						2,399	2,710
HR		137			-	770				20	3,374				
HU					1,442	-			282	228	2,978		2,666		
ME	461	596					-			189		196		3,027	
MK	426		2	3,276				-		164		87			
RO			2,452			6,469			-	2,379					
RS		902	223		1,435	2,903	873	534	118	-		286			
SI					2,202	1,830					-		2,961	7,414	
XK	920						662	507		566		-			
CE						3,228					4,035		-		
IT				1,160			1,176				3,292			-	
TR			477	528											-

We show yearly average cross-border loadings in Table 78. Cells in red show high flows (above 50%), while cells in green show low flows (below 10%). The highest loading values occur on the BG-GR border (85%, towards the ADMIE/IPTO market area), which is consistent with the high flows on that border in previous table. High loadings also occur on the BG-TR border (82%, towards Turkey). Generally, almost all links to the ADMIE/IPTO market area and Turkey are highly loaded. The TransElectrica market area's cross-border lines have notably low loadings towards the TransElectrica market area (range 3-12%), and are significantly higher in the opposite direction (range 26-67%), confirming the TransElectrica market area as an exporter of electricity.

Table 78: Cross-border loading in 2025 (High RES and low demand – PMC)

Market area	Loading (%)														
	AL	**BA**	**BG**	**GR**	**HR**	**HU**	**ME**	**MK**	**RO**	**RS**	**SI**	**XK**	**CE**	**IT**	**TR**
AL	-			49			51	33				14			
BA		-			57		17			5					
BG			-	85				66	12	45					82
GR	9		0	-				1						55	78
HR		2			-	9				1	31				
HU					14	-			3	4	28		38		
ME	21	23					-			7		15		58	
MK	16		0	45				-		19		10			
RO			26			67			-	54					
RS		34	13		66	55	33	38	3	-		22			
SI					19	17					-		36	53	
XK	17						51	36		32		-	0		
CE						46					49		-		
IT				27			22				23			-	
TR			11	14											-

Cross-border loadings in both directions (i.e., the sum of loadings in reference and counter-reference directions) are depicted in the following figure. Blue bars are borders that are coupled in all scenarios; orange bars are borders that are not coupled in the PMC scenario; and green bars are borders coupled in the PMC scenario. In this PMC scenario, the six borders shown in green are coupled: AL-XK, BA-HR, BG-MK, GR-MK, HU-RS, ME-RS.

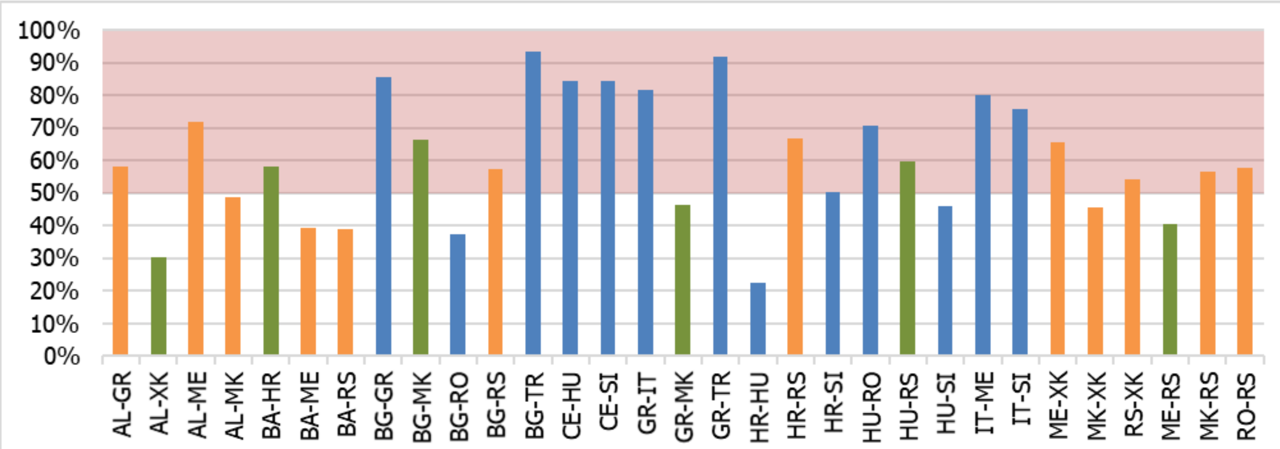


Figure 71: Cross-border loadings in both directions in 2025 (High RES and low demand – PMC)

As shown in Figure 71, cross-border loadings in both directions range from 23% to 93% depending on the border. When analyzing borders on which there are still no market couplings modelled, we note high loadings in both directions (i.e. above 50%) on the AL-GR, AL-ME, BG-RS, HR-RS, ME-XK, RS-XK, MK-RS and RO-RS borders.

Cross-border congestion represents the annual number of hours when flows on the interconnections equals or exceeds the modelled NTC. We present the cross-border congestion probability on each border in Table 79. Cells in red show high congestion probability (i.e., above 50%), while cells in green show low congestion probability (i.e., below 10%). Significant congestion probabilities exist, especially on the BG-TR and GR-TR border, but only in one direction – towards the Turkish electricity market. Other borders with high congestion probabilities are the BG-GR border (towards the ADMIE/IPTO market area) and the RS-HR border (towards the HOPS market area).

Table 79: Cross-border congestion probability in 2025 (High RES and low demand – PMC)

Market area	Congestion probability (%)														
	AL	BA	BG	GR	HR	HU	ME	MK	RO	RS	SI	XK	CE	IT	TR
AL	-			48			47	31				2			
BA		-			35		11			3					
BG			-	71				48	5	43					81
GR	8		0	-				1						54	77
HR		0			-	1				1	14				
HU					2	-			1	2	7		36		
ME	18	15					-			4		13		56	
MK	10		0	26				-		20		10			
RO			13			60			-	46					
RS		28	12		62	49	28	33	2	-		20			
SI					15	10					-		34	49	
XK	0						45	30		28		-	0		
CE						45					46		-		
IT				26			21				18			-	
TR			12	14											-

4.3.3 Full market coupling (FMC)

We depict electricity generation and consumption in the SEE region for the FMC scenario with high levels of RES penetration and low demand in Figure 72. Total generation in the SEE region in 2025 would reach 281.25 TWh, and total consumption 258.99 TWh. The highest generation is in the TransElectrica area, while the CGES area has the lowest generation, as in other scenarios.

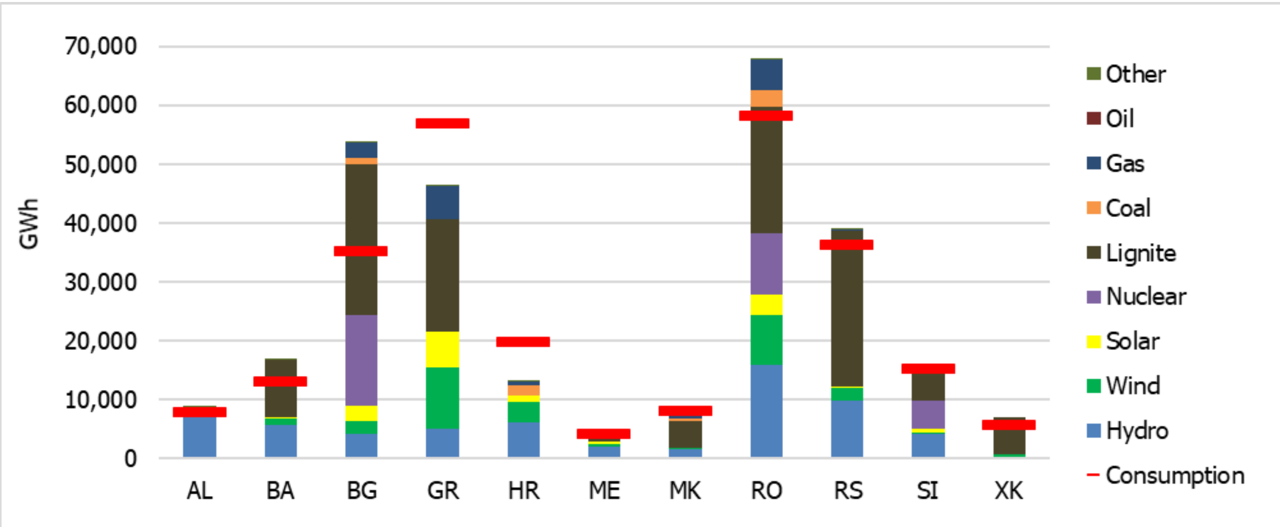


Figure 72: Electricity generation mix and consumption by market area in 2025 (High RES and low demand – FMC)

Electricity generation mix by market area is presented in more detail in the following table.

Table 80: Electricity generation mix by market area in 2025 (High RES and low demand – FMC)

Yearly generation (TWh)	AL	BA	BG	GR	HR	ME	MK	RO	RS	SI	XK	SEE
HPP	8.40	5.83	4.42	5.14	6.39	1.93	1.47	15.89	10.00	4.75	0.17	**64.37**
TPP lignite	0.00	9.74	25.71	18.93	0.00	1.49	4.42	21.57	26.41	5.11	6.24	**119.61**
TPP coal	0.00	0.00	0.94	0.00	1.61	0.00	0.45	2.81	0.00	0.00	0.00	**5.81**
TPP gas	0.00	0.00	2.70	5.70	0.76	0.00	0.65	5.31	0.19	0.35	0.00	**15.66**
TPP oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	**0.00**
TPP other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.69	0.00	0.00	0.00	**0.69**
Nuclear	0.00	0.00	15.43	0.00	0.00	0.00	0.00	10.44	0.00	4.90	0.00	**30.77**
Solar	0.11	0.14	2.51	6.28	1.12	0.41	0.09	3.36	0.26	0.62	0.14	**15.03**
Wind	0.27	1.13	2.21	10.40	3.40	0.42	0.27	8.48	2.17	0.16	0.40	**29.31**
TOTAL	**8.78**	**16.83**	**53.91**	**46.44**	**13.28**	**4.25**	**7.35**	**68.54**	**39.02**	**15.90**	**6.95**	**281.25**

In most SEE market areas, TPPs have the highest share, except in the OST, HOPS and CGES market areas, where HPPs have the highest share. Also, in the TransElectrica and ELES market areas, nuclear generation has a high share. The least diversified generation mix is in the KOSTT market area, where 90% of generation comes from TPPs.

We provide electricity balances (i.e., yearly consumption, generation and exchange values) for each of the SEE market areas in the FMC scenario in Table 81. The ESO EAD and TransElectrica market areas have the highest net interchange value, meaning they are the main net exporters in the SEE region, while the ADMIE/IPTO market area is a significant net importer, as in the case of the SM and PMC scenarios. As already mentioned, the total sum of net interchange in the SEE region is not zero since this model includes neighboring power systems (i.e., three external markets and Hungary) modelled on a technology level.

Table 81: Electricity balance in 2025 (High RES and low demand – FMC)

Electricity balance	Cons. (GWh)	Gener. (GWh)	Pump load (GWh)	Custom. load (GWh)	Imports (GWh)	Exports (GWh)	Transit (GWh)	Net inter-change (GWh)	Net import / export share (%)
AL	7,730	8,781	0	7,730	1,461	2,511	786	1,051	13.59%
BA	12,989	16,833	154	12,835	412	4,256	2024	3,844	29.59%
BG	35,076	53,913	316	34,760	0	18,837	2711	18,837	53.70%
GR	56,748	46,441	293	56,456	10,595	287	5147	-10,308	-18.16%
HR	19,715	13,275	315	19,400	6,614	174	5064	-6,439	-32.66%
ME	4,033	4,251	0	4,033	785	1,002	3936	218	5.40%
MK	7,988	7,355	0	7,988	986	352	3695	-634	-7.93%
RO	58,028	68,531	0	58,028	61	10,564	1595	10,503	18.10%
RS	36,071	39,017	276	35,795	463	3,409	6163	2,946	8.17%
SI	15,159	15,900	756	14,403	652	1,392	13425	741	4.89%
XK	5,449	6,946	0	5,449	264	1,761	713	1,497	27.47%
SEE	**258,988**	**281,242**	**2,109**	**256,879**	**22,291**	**44,545**	**45,259**	**22,254**	**8.59%**

Consumption presented in the table above refers to the total consumption calculated by adding the customer load (demand) and pumped load for pumped storage HPPs, and subtracting the energy not supplied (if it exists). Customer load is a predefined hourly input time series of demand. Pumped load values change in scenarios based on the operation of pumped storage HPPs in pumping mode.

Generation presented in the table refers to the total generation calculated by adding the generation of all modelled power plants, and subtracting the curtailed generation (if it exists).

We showed the yearly values for exports, imports, transits and net interchange for the SEE market areas in Table 81, but here they are also presented for neighboring power systems. Exports and imports values are depicted in Figure 73, transits in Figure 74, and net interchange in Figure 75. Exports are positive values, while import are negative values. In the SEE region, the ADMIE/IPTO market area is the highest net importer, and the ESO EAD market area is the highest net exporter, which we see in Figure 75. Figure 74 shows that the highest power transit is through the ELES market area, as in the SM and PMC scenarios. Regarding neighboring power systems, the highest power transits are through the Hungarian market.

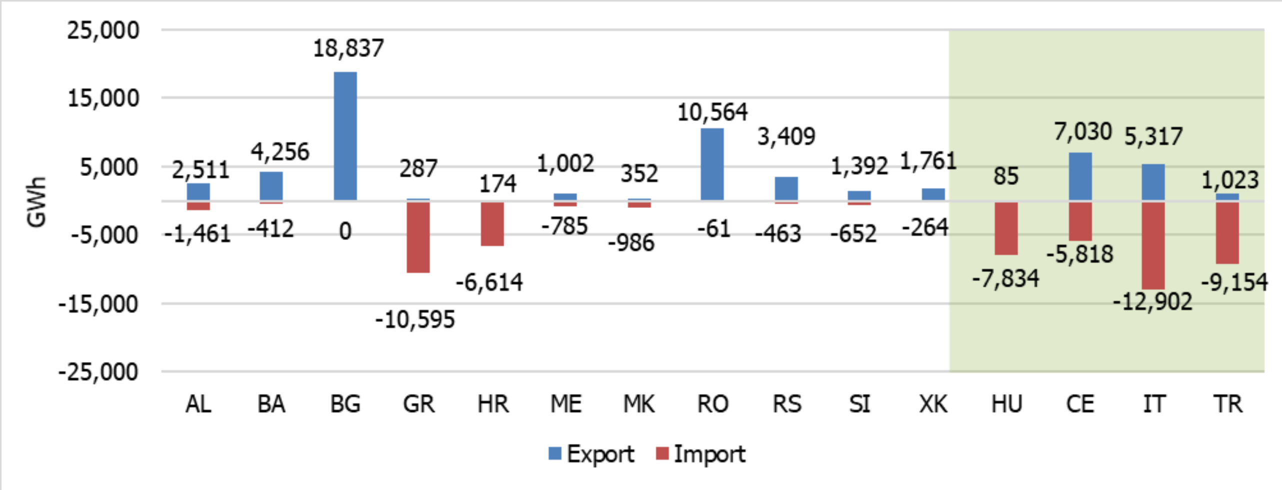


Figure 73: Imports and exports in 2025 (High RES and low demand – FMC)

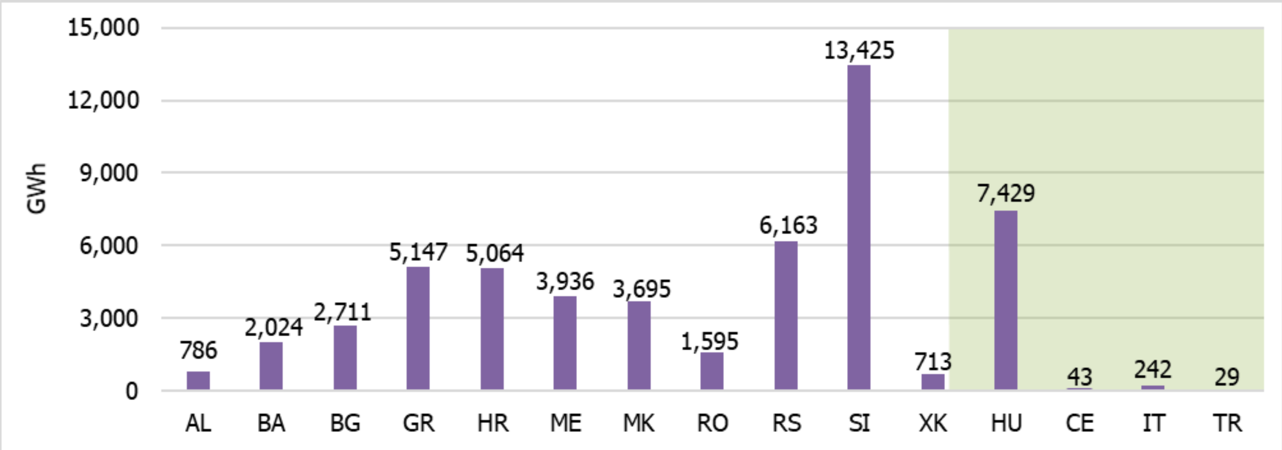


Figure 74: Transits in 2025 (High RES and low demand – FMC)

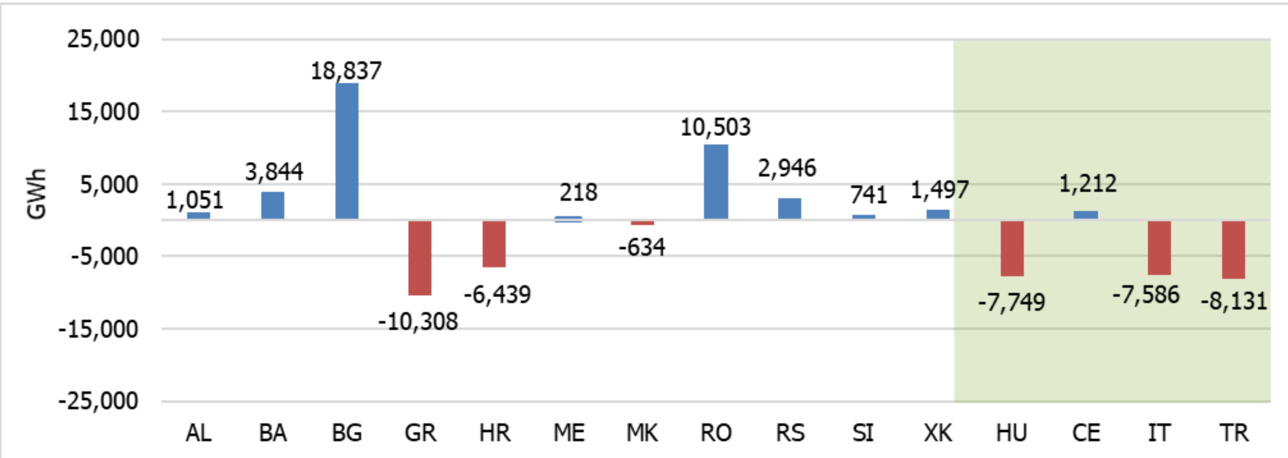


Figure 75: Net interchange in 2025 (High RES and low demand – FMC)

When observing differences among the SEE market areas, the important factor is operating cost, for which we present yearly simulation results in Table 81. The market price is determined by the marginal cost of generation and the price in neighboring markets, and the calculation of operating cost is based on variable costs, including the fuel, CO_2 and O&M cost of generating units.

The regional average operating costs in this scenario is 11.52 €/MWh. The highest average operating cost in 2025 is in the ESO EAD market area (14.67 €/MWh), where TPPs have the highest share. Table 82 also presents data about the yearly amount of CO_2 emissions in the SEE region. The highest level of CO_2 emissions is in the EMS market area. Average total operating costs, which include carbon costs, amounts to 23.68 €/MWh in the SEE region, and the KOSTT market area has the highest value (35.61 €/MWh), followed by the MEPSO market area (32.68 €/MWh). This is due to the carbon cost, which mostly affects market areas with a high share of coal TPPs.

In this scenario, the average SEE regional wholesale market price in 2025 is 50.59 €/MWh. Generally, wholesale electricity prices are harmonized in the region, even more than in the case of PMC scenario, but there are still certain variations. The HOPS and ELES market areas have a somewhat higher level of average wholesale prices than the rest of the SEE region. The highest average price is in the HOPS market area (53.49 €/MWh), while the lowest is in the TransElectrica market area (48.78 €/MWh).

Table 82: Operating costs in 2025 (High RES and low demand – FMC)

Operating costs without and with emissions costs	AL	BA	BG	GR	HR	ME	MK	RO	RS	SI	XK	SEE
Operating costs (mil. €)	0	153	791	558	85	23	105	894	389	156	88	**3,241**
CO_2 emissions (mil. tonne)	0	12	26	20	2	1	5	27	28	5	6	**133**
CO_2 emissions costs (mil. €)	0	314	658	522	48	38	136	707	708	129	160	**3,418**
Total operating costs (mil. €)	0	467	1,449	1,080	133	61	240	1,601	1,096	285	247	**6,659**
Average operating costs (€/MWh)	0.00	9.10	14.67	12.02	6.39	5.36	14.24	13.05	9.96	9.81	12.61	**11.52**
Average total operating costs (€/MWh)	0.00	27.72	26.87	23.26	10.04	14.29	32.68	23.36	28.10	17.90	35.61	**23.68**
Price (€/MWh)	50.43	50.33	49.76	51.00	53.49	50.11	49.77	49.78	49.84	53.16	50.02	**50.59**

We analyze yearly cross-border exchange, loading and congestions results below.

ELES has the highest cross-border exchange (Table 83) (i.e., 28,895 GWh, with 14,818 GWh of exports to neighboring areas, and 14,077 GWh of imports in the opposite direction). The KOSTT market area has the lowest yearly cross-border exchange in the SEE region (i.e., 3,450 GWh, with 2,474 GWh of exports to neighboring market areas, and 977 GWh of imports in the opposite direction). For individual border flows, we note the highest yearly flow on the BG-GR border, from the ESO EAD market area to the ADMIE/IPTO market area, showing that imports to the ADMIE/IPTO market area mostly come from the ESO EAD market area, as in the SM and PMC scenarios.

Table 83: Cross-border exchange in 2025 (High RES and low demand – FMC)

Market area	Flow (GWh)														
	AL	**BA**	**BG**	**GR**	**HR**	**HU**	**ME**	**MK**	**RO**	**RS**	**SI**	**XK**	**CE**	**IT**	**TR**
AL	-			1,038			1,366	631				262			
BA		-			5,481		639			160					
BG			-	9,761				2,478	1,371	1,498					6,440
GR	143		0	-				118						2,428	2,744
HR		147			-	1,095				40	3,958				
HU					1,184	-			229	308	3,002		2,790		
ME	805	791					-			94		161		3,088	
MK	501		7	3,264				-		184		90			
RO			1,897			6,327			-	3,936					
RS		1,498	283		2,781	2,783	799	908	56	-		464			
SI					2,231	1,887					-		3,071	7,629	
XK	798						723	546		407		-			
CE						3,172					3,901		-		
IT				1,149			1,193				3,217			-	
TR			524	529											-

Yearly average cross-border loadings are given in Table 84. Cells in red show high flows (i.e., loadings above 50%), while cells in green show low flows (i.e., loadings below 10%).

In this scenario the highest cross-border loading values also occur on the BG-GR border (83%, towards the ADMIE/IPTO market area), which is consistent with the high flows on that border in the previous table. High loadings also occur on BG-TR border (82%, towards Turkey). Generally, almost all links to the ADMIE/IPTO market area and Turkey are highly loaded, as in the SM and PMC scenarios. The TransElectrica market area cross-border lines are notably less loaded towards the TransElectrica market area (1-13%), and significantly higher in the opposite direction (20-66%), confirming that the TransElectrica market area is also an exporter of electricity in the FMC scenario.

Table 84: Cross-border loading in 2025 (High RES and low demand – FMC)

Market area	Loading (%)														
	AL	**BA**	**BG**	**GR**	**HR**	**HU**	**ME**	**MK**	**RO**	**RS**	**SI**	**XK**	**CE**	**IT**	**TR**
AL	-			48			31	18				5			
BA		-			56		12			3					
BG			-	83				57	13	43					82
GR	7		0	-				2						56	79
HR		2			-	13				1	36				
HU					11	-			3	6	29		40		
ME	18	15					-			4		6		59	
MK	10		0	45				-		11		5			
RO			20			66			-	45					
RS		29	8		64	53	31	32	1	-		18			
SI					20	18					-		37	55	
XK	14						28	19		12		-	0		
CE						45					47		-		
IT				26			23				22			-	
TR			12	14											-

We depict cross-border loadings in both directions (i.e., the sum of loadings in the reference and counter-reference directions) in the following figure. Blue bars are borders that are coupled in all scenarios, while green bars borders that are coupled for this scenario. In this FMC scenario, all 18 borders shown in the green bars are coupled.

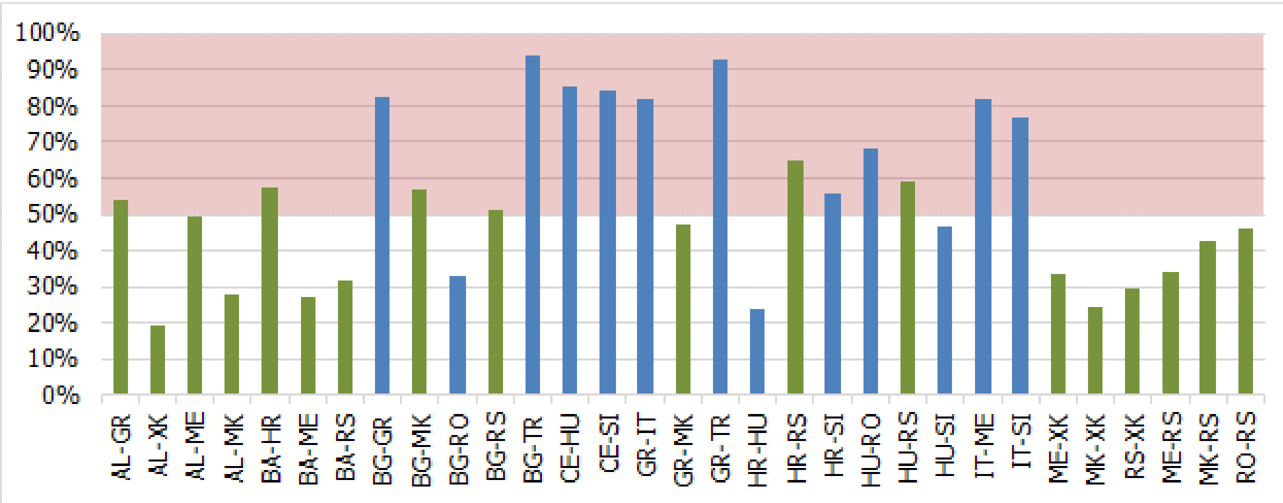


Figure 76: Cross-border loadings in both directions in 2025 (High RES and low demand – FMC)

As it can be seen from Figure 76, cross-border loadings in both directions range from 19% to 94% depending on the border. When analyzing borders on which we modelled market couplings, we can still notice high loadings in both directions (i.e. above 50%) on the AL-GR, BA-HR, BG-MK, BG-RS, HR-RS and HU-RS borders, but significantly lower than in the SM scenario.

Cross-border congestions represent the number of hours in a year where flow on interconnections equals or would exceed the modelled NTC. We present the cross-border congestion probability for each border in Table 85. Cells in red show high congestion probability (i.e., above 50%), while cells in green have low congestion probability (i.e., below 10%). We note significant congestion probabilities, especially on the BG-TR and GR-TR borders, but only in one direction – towards the Turkish electricity market. There is also a high congestion probability on BG-GR border (towards the ADMIE/IPTO market area). When looking at borders coupled in this FMC scenario that were not coupled in the SM scenario, we generally note a decrease in congestion probability.

Table 85: Cross-border congestion probability in 2025 (High RES and low demand – FMC)

Market area	Congestion probability (%)														
	AL	BA	BG	GR	HR	HU	ME	MK	RO	RS	SI	XK	CE	IT	TR
AL	-			44			19	12				0			
BA		-			41		4			1					
BG			-	67				39	5	38					81
GR	6		0	-				1						55	78
HR		0			-	3				0	20				
HU					1	-			1	3	6		38		
ME	10	5					-			2		3		58	
MK	3		0	28				-		10		4			
RO			9			58			-	24					
RS		17	6		58	49	24	26	0	-		12			
SI					16	11					-		35	50	
XK	1						18	9		4		-	0		
CE						45					45		-		
IT				26			22				17			-	
TR			13	14											-

4.3.4 Comparison of different market coupling scenarios

The following table compares total electricity generation in the SEE region for different analyzed market coupling scenarios, using absolute values (TWh) and percentages (%). Generation in this table refers to the total generation calculated by adding the generation of all modelled power plants, and subtracting curtailed generation (if any).

Total electricity generation is higher in the PMC scenario by 2.73 TWh (0.98%) and in the FMC scenario by 3.36 TWh (1.21%) compared to the SM scenario, and this increase is due to the higher possibility of electricity exports in integrated markets. In all scenarios the highest generation is in the TransElectrica market area and the lowest in the CGES market area, but we note the effect of market coupling on specific areas. The most significant change in the PMC scenario occurs in the NOSBiH market area, where yearly generation rises by 1.39 TWh (8.60%) and in the FMC scenario by 0.67 TWh (4.17%) compared to the SM scenario. Also, the FMC scenario has a large effect on the level of generation (TWh) in the TransElectrica market area, increasing by 1.66 TWh (2.48%) compared to the SM scenario. In some market areas there would be little change (for example in the OST and CGES market areas), due to the lack of TPPs, which are able to increase generation.

Table 86: Comparison of electricity generation by market area in 2025 (High RES and low demand)

Yearly generation (TWh)	AL	BA	BG	GR	HR	ME	MK	RO	RS	SI	XK	SEE
Separated markets	8.78	16.16	52.40	47.34	13.66	4.25	7.15	66.87	38.49	16.02	6.75	**277.88**
Partial market coupling	8.78	17.55	53.37	46.47	13.40	4.25	7.36	67.68	39.03	15.93	6.79	**280.61**
Change (TWh)	0.00	1.39	0.97	-0.87	-0.26	0.00	0.21	0.81	0.54	-0.10	0.04	**2.73**
Change (%)	0.00	8.60	1.85	-1.85	-1.91	0.04	3.00	1.21	1.40	-0.60	0.66	**0.98**
Full market coupling	8.78	16.83	53.91	46.44	13.28	4.25	7.35	68.53	39.02	15.90	6.95	**281.24**
Change (TWh)	0.00	0.67	1.51	-0.90	-0.39	0.00	0.21	1.66	0.53	-0.12	0.20	**3.36**
Change (%)	0.00	4.17	2.88	-1.91	-2.82	-0.02	2.88	2.48	1.38	-0.76	2.93	**1.21**

We present a comparison of yearly export values in Table 87, import values in Table 88 and transit values in Table 89. We should analyze all these tables together with Figure 77.

In all scenarios, the ADMIE/IPTO and HOPS market areas are the highest electricity importers, while the ESO EAD and TransElectrica market areas are the highest exporters. The highest transit is through the ELES market area.

In total, SEE region electricity exports increase by 3,375 GWh (8%) in the PMC scenario and by 4,776 GWh (12%) in the FMC scenario compared to the SM scenario (a substantial increase). The highest increase of exports in GWh is in the NOSBiH market area in the PMC scenario and in the TransElectrica market area in the FMC scenario. Consistent with the increase of electricity generation, this area has the highest increase of exports, (i.e., up to a 96% in the FMC scenario).

Electricity imports also increase with market integration – in the PMC scenario by 754 GWh (4%) and in the FMC scenario by 1,252 GWh (6%).

Table 87: Comparison of export by market area in 2025 (High RES and low demand)

Export (GWh)	AL	BA	BG	GR	HR	ME	MK	RO	RS	SI	XK	SEE
Separated markets	2,229	3,609	17,386	162	443	945	179	8,915	2,864	1,413	1,624	**39,769**
Partial market coupling	2,337	4,743	18,310	170	256	1,016	312	9,712	3,240	1,389	1,661	**43,144**
Change (GWh)	108	1,134	923	8	-187	71	132	797	377	-24	37	**3,375**
Change (%)	4.84	31.42	5.31	4.84	-42.20	7.51	73.91	8.93	13.15	-1.72	2.29	**8.49**
Full market coupling	2,511	4,256	18,837	287	174	1,002	352	10,564	3,409	1,392	1,761	**44,545**
Change (GWh)	282	647	1,450	125	-269	57	173	1,648	546	-20	137	**4,776**
Change (%)	12.67	17.92	8.34	76.84	-60.66	6.06	96.40	18.49	19.05	-1.44	8.46	**12.01**

Table 88: Comparison of import by market area in 2025 (High RES and low demand)

Import (GWh)	AL	BA	BG	GR	HR	ME	MK	RO	RS	SI	XK	SEE
Separated markets	1,178	394	0	9,623	6,576	726	1,019	71	447	681	325	**21,039**
Partial market coupling	1,286	262	0	10,465	6,596	796	937	61	413	661	317	**21,793**
Change (GWh)	108	-132	0	842	20	69	-82	-10	-34	-20	-8	**754**
Change (%)	9.16	-33.52	-2.86	8.75	0.30	9.56	-8.04	-14.62	-7.60	-2.96	-2.31	**3.58**
Full market coupling	1,461	412	0	10,595	6,614	785	986	61	463	652	264	**22,291**
Change (GWh)	282	19	0	972	38	58	-33	-10	16	-29	-60	**1,252**
Change (%)	23.98	4.76	2.86	10.10	0.58	8.03	-3.27	-14.51	3.63	-4.29	-18.55	**5.95**

Figure 77 depicts comparison of yearly exports and imports for different market coupling scenarios.

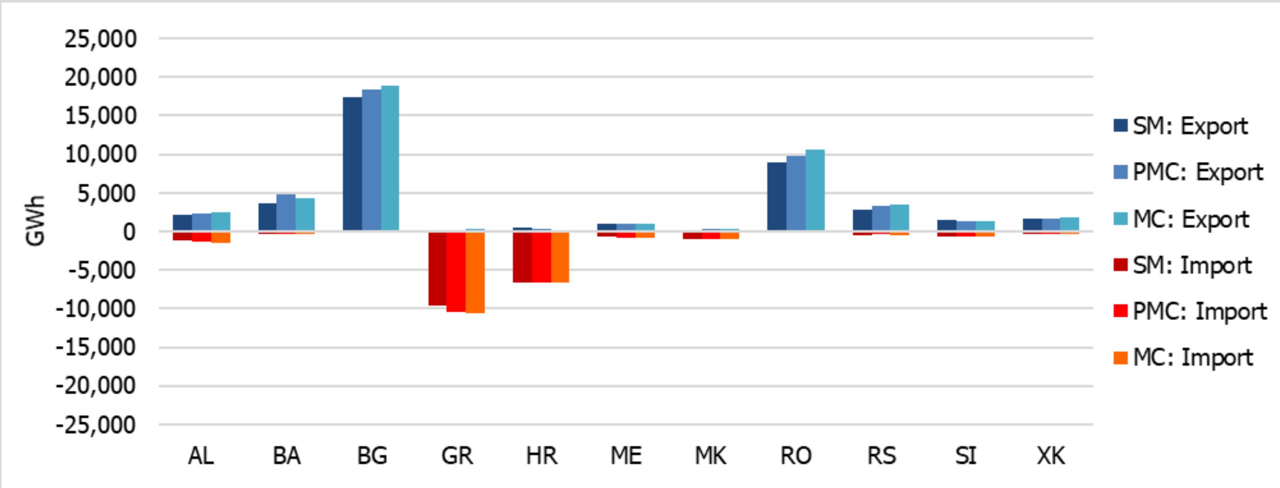


Figure 77: Comparison of exports and imports in 2025 (High RES and low demand)

In comparing electricity exchange between the scenarios, we conclude the following. First, on a regional level, exports increase more than import, so there is greater net exchange in the PMC and FMC scenarios compared with SM. For the region as whole, exports rise with greater coupling, as now transmission utilization can more exports of lower-cost electricity to neighboring systems, such as Hungary, Turkey and Italy. Second, the vast majority of countries increase exports with greater market integration (with a few exceptions). This is logical, given that coupling allows better utilization of transmission, and also unlocks generation in exporting areas, substituting for expensive imports.

In addition, in Table 89 shows that in both the PMC and FMC cases, transits change notably compared with transits in the SM situation. Transits essentially represent flows of electricity through one power system as a result of an exchange between two other power systems. We conclude that market integration would meaningfully boost energy exchanges and flows across the SEE region.

Table 89: Comparison of transits in 2025 (High RES and low demand)

Transit (GWh)	AL	BA	BG	GR	HR	ME	MK	RO	RS	SI	XK	SEE
Separated markets	565	905	2,808	4,964	2,366	3,314	2,315	1,761	3,052	12,149	724	**34,923**
Partial market coupling	616	1,373	3,154	5,112	4,045	3,452	3,643	1,588	4,034	13,019	994	**41,030**
Change (GWh)	51	468	346	148	1,679	138	1,328	-173	982	870	270	**6,107**
Change (%)	9.03	51.71	12.32	2.98	70.96	4.16	57.37	-9.82	32.18	7.16	37.29	**17.49**
Full market coupling	786	2,024	2,711	5,147	5,064	3,936	3,695	1,595	6,163	13,425	713	**45,259**
Change (GWh)	221	1,119	-97	183	2,698	622	1,380	-166	3,111	1,276	-11	**10,336**
Change (%)	39.12	123.65	-3.45	3.69	114.03	18.77	59.61	-9.43	101.93	10.50	-1.52	**29.60**

As mentioned, electricity imports in absolute values (GWh) does not increase as much as exports, so in total, the SEE region becomes a higher net exporter of electricity in the PMC and FMC scenarios. We show the results of yearly net interchange values by market area in Table 90. As already mentioned, net interchange is calculated as the difference between exports and imports, hence a positive net interchange value means that the market area is a net exporter.

In total, in the SEE region, net interchange increases by 2,622 GWh in the PMC scenario and by 3,524 GWh in the FMC scenario compared to the SM scenario. Generally, the ESO EAD market area has the highest positive net interchange in all scenarios. An increase in net interchange is especially visible in market areas with increased transmission capacities for commercial exchange due to market coupling, such as the NOSBiH, ESO EAD and TransElectrica market areas. For example, net interchange of the NOSBiH market area would increase by a substantial amount - 1,266 GWh - in the PMC scenario, and by 628 GWh in the FMC scenario, compared to the SM scenario.

Table 90: Comparison of net interchange by market area in 2025 (High RES and low demand)

Net interchange (GWh)	AL	BA	BG	GR	HR	ME	MK	RO	RS	SI	XK	SEE
Separated markets	1,051	3,216	17,386	-9,461	-6,133	219	-840	8,844	2,417	732	1,299	**18,730**
Partial market coupling	1,051	4,481	18,309	-10,295	-6,340	220	-625	9,651	2,827	728	1,344	**21,352**
Change (GWh)	0	1,266	923	-835	-207	2	214	807	411	-4	45	**2,622**
Full market coupling	1,051	3,844	18,837	-10,308	-6,439	218	-634	10,503	2,946	741	1,497	**22,254**
Change (GWh)	0	628	1,450	-847	-306	-1	206	1,659	529	9	198	**3,524**

We depict the exchanges of Hungary, Italy, Turkey and Central Europe with the SEE region in the following figures for the SM, PMC and FMC scenarios (Figure 78 to Figure 80), with values in arrows showing the exchange direction – blue arrows show exports from the SEE region to specific neighboring areas, and red arrows show import to the SEE region from neighboring market areas.

In all scenarios, the SEE region exports more electricity to neighboring market areas than it imports. With an increase of market integration, the SEE region becomes a stronger net exporter. Neighboring market areas import from the SEE region 32,613 GWh in the SM scenario, 34,919 GWh in the PMC scenario, and 35,709 GWh in the FMC scenario. At the same time, they export a decreasing amount to the SEE region - 14,154 GWh of electricity in the SM scenario, 13,567 GWh in the PMC scenario and 13,455 GWh in the FMC scenario.

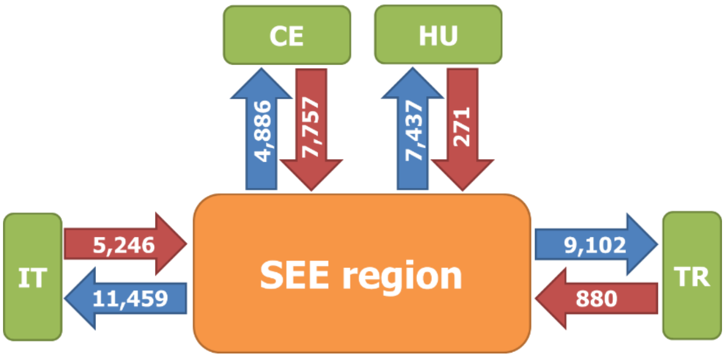


Figure 78: Hungary, Italy, Turkey, Central Europe and SEE region exchange in 2025 (High RES and low demand – SM)

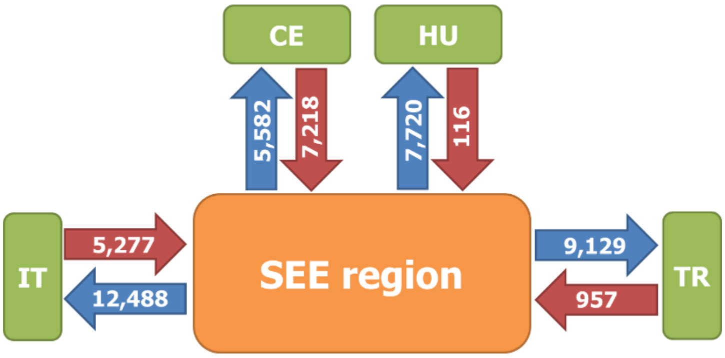


Figure 79: Hungary, Italy, Turkey, Central Europe and SEE region exchange in 2025 (High RES and low demand – PMC)

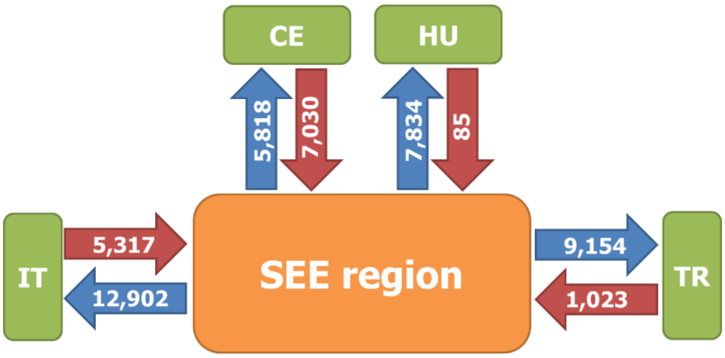


Figure 80: Hungary, Italy, Turkey, Central Europe and SEE region exchange in 2025 (High RES and low demand – FMC)

Comparison of yearly net interchange values for different market coupling scenarios is presented in Figure 81. In this comparison it is also visible that in all scenarios, the SEE region on a yearly basis imports electricity from Central Europe, and exports electricity to Italy, Turkey and Hungary.

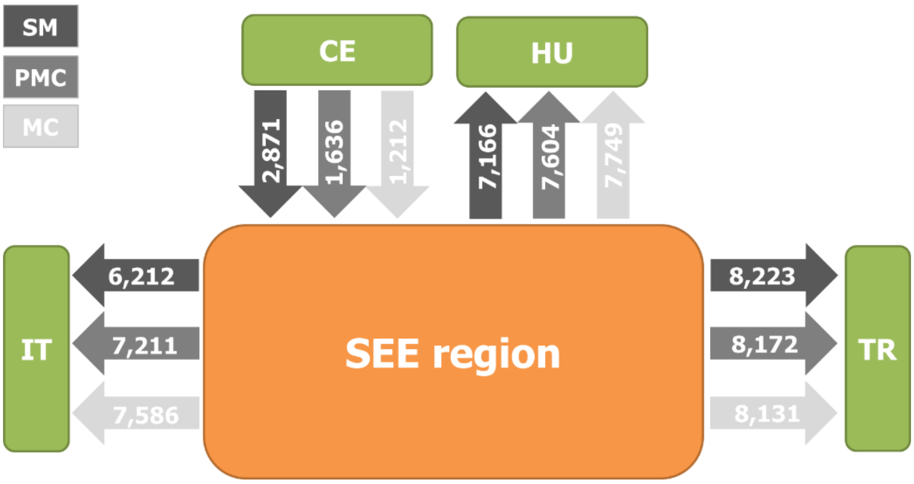


Figure 81: Hungary, Italy, Turkey, Central Europe and SEE region net interchange in 2025 (High RES and low demand – comparison of the coupling scenarios)

In our work, the market price is set by the marginal cost of generation and the price in neighboring markets. We present the resulting wholesale prices by market in Table 91. The average wholesale market price in the SEE region is the load-weighted average of all the market areas. This price amounts to 50.04 €/MWh in the SM scenario, 50.41 €/MWh in the PMC scenario, and 50.59 €/MWh in the FMC scenario. Thus, the average SEE market price in the PMC scenario is 0.37 €/MWh (0.73%) higher than in the SM scenario, and in the FMC scenario is 0.55 €/MWh (1.10%) higher.

This is an intriguing result. In the prior scenarios (Baseline and Dry hydrology), the average market prices in the SEE region decrease with market, while in this set of scenarios, which combines high RES and low demand, the average market prices rise with market integration in most SEE market areas. This is because the higher electricity generation from RES and the lower demand in the SEE region causes generally lower wholesale electricity prices compared to the neighboring electricity markets. Market integration enables higher transit of electricity through the SEE region, and the increased export to neighboring areas causes a slight increase in the average SEE regional price.

However, in some market areas prices fall in the PMC and FMC scenarios compared to the SM scenario. For example, in the ADMIE/IPTO, HOPS and ELES market areas, wholesale prices are lower in the PMC and FMC scenarios, and the highest decrease of market price is in the HOPS market area where market prices fall by 1.07 €/MWh in the PMC scenario and 1.48 €/MWh in the FMC scenario, compared to the SM scenario. The most significant price increase in the PMC scenario occurs in the EMS and NOSBiH market areas, due to increased TPPs production in these market areas and coupling with market areas with higher market prices. In the FMC scenario, the market price significantly increases in the TransElectrica market area as well.

Price convergence for the whole region can be seen in the next-to-last column of Table 91, next to the coefficient of price variation (CV). The CV is expressed as a percentage, calculated as the ratio of the standard deviation to the mean (average) of prices in the EMI market areas. As market integration gets stronger, the CV falls, meaning that prices are less dispersed.

Table 91: Comparison of average wholesale prices by market area in 2025 (High RES and low demand)

Price (€/MWh)	AL	BA	BG	GR	HR	ME	MK	RO	RS	SI	XK	SEE	CV
Separated markets	49.37	49.47	48.14	51.93	54.97	49.44	48.88	48.01	48.41	54.59	48.80	**50.04**	**4.76%**
Partial market coupling	50.15	51.09	49.10	50.96	53.90	50.66	49.60	48.89	50.06	53.56	49.75	**50.41**	**3.11%**
Change (€/MWh)	0.78	1.62	0.95	-0.97	-1.07	1.22	0.73	0.88	1.65	-1.03	0.95	**0.37**	
Change (%)	1.59	3.28	1.98	-1.86	-1.94	2.46	1.49	1.83	3.42	-1.90	1.95	**0.73**	
Full market coupling	50.43	50.33	49.76	51.00	53.49	50.11	49.77	49.78	49.84	53.16	50.02	**50.59**	**2.54%**
Change (€/MWh)	1.06	0.86	1.62	-0.93	-1.48	0.66	0.89	1.78	1.43	-1.44	1.23	**0.55**	
Change (%)	2.15	1.74	3.37	-1.79	-2.69	1.34	1.83	3.70	2.96	-2.63	2.51	**1.10**	

We compare the average wholesale prices in different scenarios in Figure 82.

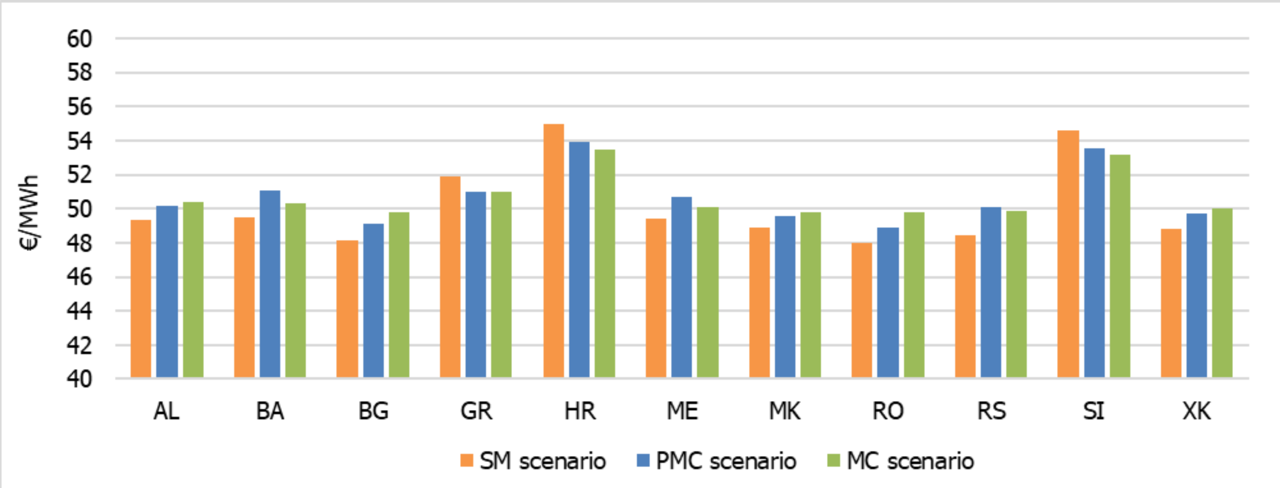


Figure 82: Comparison of average wholesale prices in 2025 (High RES and low demand)

After analyzing the different market parameters, we calculate the change in social-economic welfare (SEW) to fully evaluate the overall benefits of regional market integration in the SEE region, as in the prior scenarios. SEW is measured as the change in consumer surplus, producer surplus and total congestion rents in the PMC and FMC scenarios compared to the SM scenario. We present the SEW in different market integration options for each of the EMI market areas in the following table.

Table 92: Comparison of socio-economic welfare changes in 2025 (High RES and low demand)

Market area	Partial market coupling - Separated markets				Full market coupling - Separated markets			
million €	Δ Producer surplus	Δ Consumer surplus	Δ Congestion rent	Δ Total surplus	Δ Producer surplus	Δ Consumer surplus	Δ Congestion rent	Δ Total surplus
AL	8.88	-6.05	-0.75	**2.08**	14.37	-8.20	-2.45	**3.72**
BA	28.22	-20.83	-0.46	**6.93**	17.23	-11.07	0.21	**6.37**
BG	48.31	-33.12	-12.06	**3.13**	86.79	-56.31	-21.26	**9.21**
GR	-38.67	54.64	-15.26	**0.71**	-31.49	52.41	-19.84	**1.07**
HR	-20.88	20.69	-2.01	**-2.20**	-29.09	28.66	3.47	**3.05**
ME	6.56	-4.91	-1.86	**-0.21**	4.02	-2.68	-2.87	**-1.53**
MK	6.07	-5.81	-1.32	**-1.06**	8.12	-7.13	-3.85	**-2.86**
RO	57.91	-51.11	-6.64	**0.15**	121.09	-103.11	-16.27	**1.71**
RS	61.67	-59.18	0.37	**2.85**	55.60	-51.25	-2.53	**1.82**
SI	-15.44	14.91	9.56	**9.02**	-21.34	20.70	14.60	**13.96**
XK	7.16	-5.20	0.26	**2.23**	9.11	-6.68	-1.65	**0.77**
TOTAL SEE	**149.78**	**-95.96**	**-30.18**	**23.64**	**234.41**	**-144.67**	**-52.46**	**37.28**

In this group of scenarios, with high RES and low demand assumptions, the SEW for the SEE region in the PMC scenario amounts to 23.64 million €, while in the FMC scenario is 37.28 million €.

Looking at each market area, there are areas with both positive and negative changes in SEW, which should not be considered as negative for market coupling.

The highest benefits can be expected in the ELES and ESO EAD market areas. In the ELES market area it is mainly due to the increase in congestion rent that may be expected after stronger market coupling in the SEE region. In the ESO EAD market area, higher export with increase in prices in the ESO EAD market area and small decrease in prices in the ADMIE/IPTO market area provides positive changes in social economic welfare.

In almost all market areas, greater market coupling leads to a decrease in congestion rents which is expected, as such coupling makes more cross-border capacities available for market transactions. In some market areas, this decrease in congestion rents can lead to a negative total surplus, while in other market areas positioned between two distinct price groups (like the ELES market area) there can be benefits from increased congestion rents. In most market areas, price convergence with more cross-border capacities leads to lower congestion rents for TSOs. While congestion rents are part of the SEW calculation, there are questions as to whether to include congestion rents in this analysis.

As the table shows, almost all market areas benefit from market coupling when we just sum the producer and consumer surpluses. In the exporting market areas, the benefits are more on the producers' side, while in the importing ones, on consumers side, due to higher/lower prices, respectively. We present the sum of changes in producer and consumer surpluses in Table 93.

Table 93: Comparison of the sum of changes in producer and consumer surpluses in 2025 (High RES and low demand)

Market area	Partial market coupling - Separated markets			Full market coupling - Separated markets		
million €	Δ Producer surplus	Δ Consumer surplus	Δ Sum	Δ Producer surplus	Δ Consumer surplus	Δ Sum
AL	8.88	-6.05	2.83	14.37	-8.20	6.17
BA	28.22	-20.83	7.40	17.23	-11.07	6.15
BG	48.31	-33.12	15.19	86.79	-56.31	30.47
GR	-38.67	54.64	15.97	-31.49	52.41	20.92
HR	-20.88	20.69	-0.19	-29.09	28.66	-0.42
ME	6.56	-4.91	1.65	4.02	-2.68	1.34
MK	6.07	-5.81	0.26	8.12	-7.13	0.99
RO	57.91	-51.11	6.80	121.09	-103.11	17.98
RS	61.67	-59.18	2.48	55.60	-51.25	4.35
SI	-15.44	14.91	-0.53	-21.34	20.70	-0.64
XK	7.16	-5.20	1.97	9.11	-6.68	2.43
TOTAL SEE	**149.78**	**-95.96**	**53.82**	**234.41**	**-144.67**	**89.74**

The HOPS and SI market areas are quite balanced. In the HOPS market area, coupling with the NOSBIH market area (in PMC) and further coupling with the EMS market area (in FMC) would reduce prices, but still keeps a high level of internal generation, so the increase of consumer surplus is more than offset by slightly larger decrease in producer surplus. In the ELES market area the sum of producer and consumer surpluses is either zero or a small negative value.

4.4 Set of scenarios with high level of RES penetration, low demand and dry hydrological conditions

4.4.1 Separated (non-coupled) markets (SM)

These analyses combine all three changes that we evaluated: high RES penetration, low demand and low hydro availability. Under these conditions, we show electricity generation and consumption for the SM scenario in Figure 83. Total generation in the SEE region would amount to 272.71 TWh, while total consumption would reach 259.78 TWh. As in other cases, the highest generation is in the TransElectrica market area, while the CGES market area has the lowest generation.

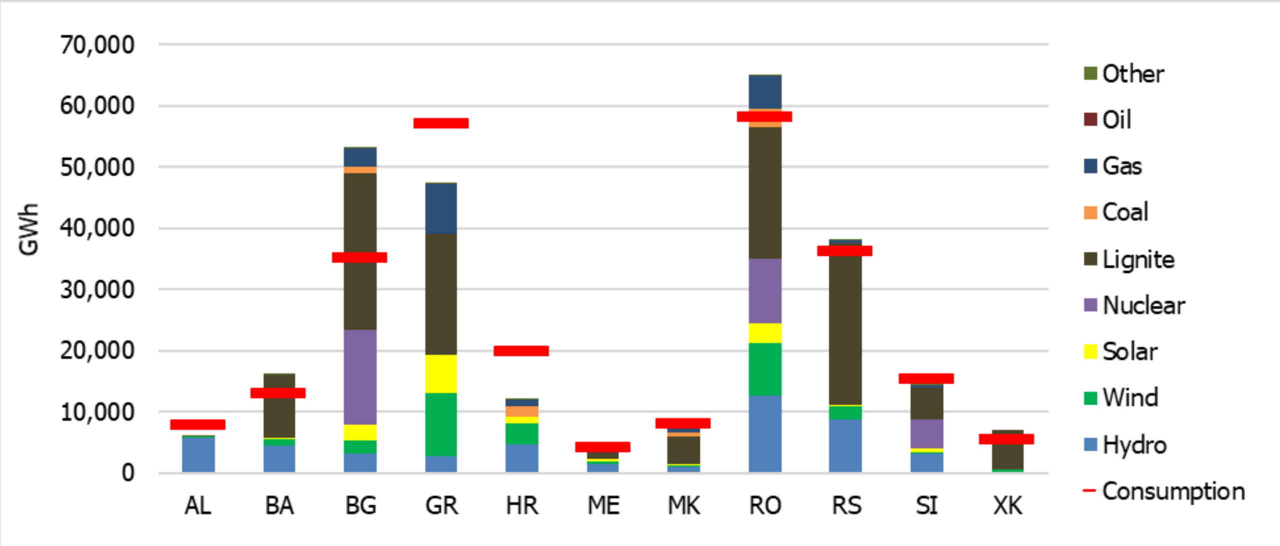


Figure 83: Electricity generation mix and consumption by market area in 2025 (High RES, low demand and dry hydrological conditions – SM)

The following table presents the electricity generation mix by market area in more detail.

Table 94: Electricity generation mix by market area in 2025 (High RES, low demand and dry hydrological conditions – SM)

Yearly generation (TWh)	AL	BA	BG	GR	HR	ME	MK	RO	RS	SI	XK	SEE
HPP	5.65	4.58	3.47	3.12	4.91	1.45	1.03	12.71	9.14	3.81	0.13	**49.99**
TPP lignite	0.00	10.31	25.78	19.72	0.00	1.50	4.61	21.53	26.42	5.13	6.45	**121.46**
TPP coal	0.00	0.00	1.01	0.00	1.70	0.00	0.51	2.94	0.00	0.00	0.00	**6.16**
TPP gas	0.00	0.00	3.07	8.25	1.15	0.00	0.70	5.44	0.27	0.41	0.00	**19.29**
TPP oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	**0.00**
TPP other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.72	0.00	0.00	0.00	**0.72**
Nuclear	0.00	0.00	15.42	0.00	0.00	0.00	0.00	10.44	0.00	4.90	0.00	**30.76**
Solar	0.11	0.14	2.51	6.28	1.12	0.41	0.09	3.36	0.26	0.62	0.14	**15.03**
Wind	0.27	1.13	2.21	10.40	3.40	0.42	0.27	8.48	2.17	0.16	0.40	**29.31**
TOTAL	**6.03**	**16.15**	**53.48**	**47.78**	**12.28**	**3.78**	**7.22**	**65.61**	**38.25**	**15.04**	**7.11**	**272.71**

In most of the SEE market areas, TPPs have the highest share, except in the OST and HOPS market areas, where HPPs have the highest share, and in the TransElectrica, ESO EAD and ELES market areas, where nuclear generation has a significant share. The least diversified generation mix is in the KOSTT market area, where 90% of electricity generation comes from TPPs.

We provide the electricity balances (i.e., yearly consumption, generation and exchange values) for each of the SEE market areas in the SM scenario in Table 95. The ESO EAD and TransElectrica market areas have the highest net interchange, meaning they are the main net exporters in the SEE region, while the ADMIE/IPTO market area is a significant net importer. Thel sum of net interchange in the SEE region is not zero, since this model includes neighboring power systems (i.e., three external markets and Hungary) modelled on a technology level.

Table 95: Electricity balance in 2025 (High RES, low demand and dry hydrological conditions – SM)

Electricity balance	Cons. (GWh)	Gener. (GWh)	Pump load (GWh)	Custom. load (GWh)	Imports (GWh)	Exports (GWh)	Transit (GWh)	Net inter-change (GWh)	Net import / export share (%)
AL	7,730	6,030	0	7,730	2,337	637	670	-1,700	-22.00%
BA	13,020	16,149	185	12,835	401	3,529	831	3,128	24.03%
BG	35,205	53,478	444	34,760	0	18,273	2352	18,273	51.91%
GR	57,011	47,775	556	56,456	9,477	242	4618	-9,236	-16.20%
HR	19,795	12,275	395	19,400	7,821	301	1933	-7,520	-37.99%
ME	4,033	3,780	0	4,033	852	600	3338	-253	-6.27%
MK	7,988	7,217	0	7,988	989	217	2295	-772	-9.66%
RO	58,028	65,601	0	58,028	121	7,694	2292	7,572	13.05%
RS	36,231	38,251	436	35,795	575	2,595	3071	2,020	5.57%
SI	15,293	15,039	890	14,403	1,151	897	12461	-254	-1.66%
XK	5,449	7,112	0	5,449	233	1,895	578	1,662	30.50%
SEE	**259,784**	**272,706**	**2,907**	**256,879**	**23,958**	**36,880**	**34,438**	**12,922**	**4.97%**

Consumption in the table above is calculated by adding the customer load (demand) and load for pumped storage HPPs, and subtracting the energy not supplied (if it exists). Customer load is a predefined hourly input time series of demand. Pumped load values change in the scenarios, based on the operation of pumped storage HPPs in pumping mode.

Generation presented in this table refers to the total generation, calculated by adding the generation of all modelled power plants, and subtracting curtailed generation (if it exists).

We previously showed yearly values for exports, imports, transits and net interchange for the SEE market areas in Table 95, but here we also present figures for neighboring power systems. We depict exports and imports in Figure 84, transits in Figure 85, and net interchange in Figure 86. Export are positive values, while imports are negatives. In the SEE region, the ADMIE/IPTO market area is the highest net importer, and the ESO EAD market area is the highest net exporter, as shown in Figure 86. Figure 85 shows that the highest power transit is through ELES, due to both high import and export values. Regarding neighboring systems, the highest transits are through Hungary. While Hungary, Italy and Turkey mostly import from the SEE region, Central Europe mostly exports electricity to the SEE region, which is expected, given the lower level of assumed wholesale market price in Central Europe compared to other neighboring markets (as presented in Chapter 2.5).

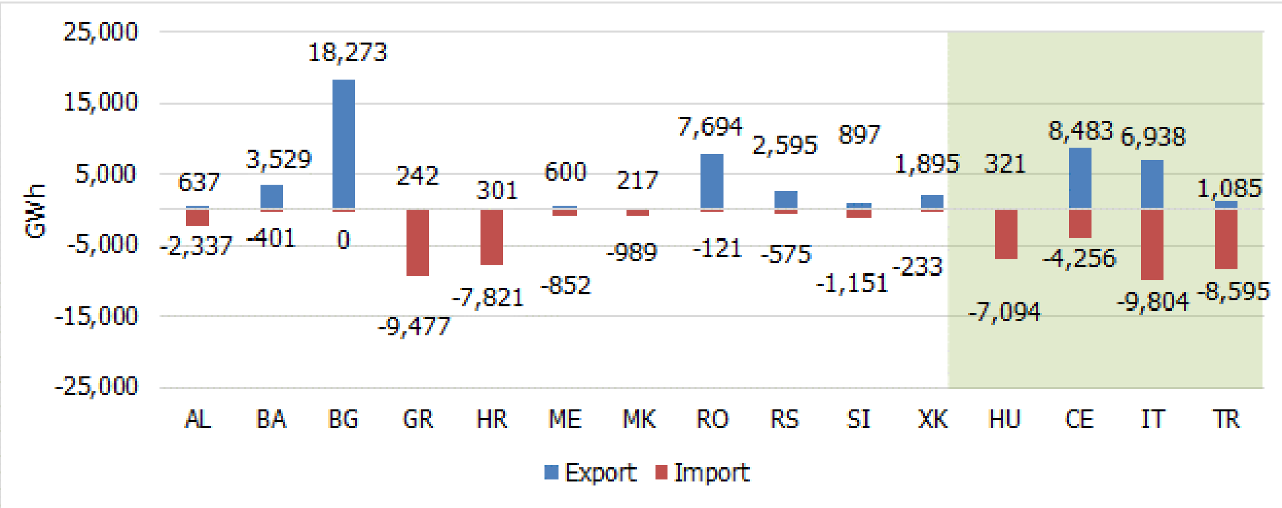


Figure 84: Imports and exports in 2025 (High RES, low demand and dry hydrological conditions – SM)

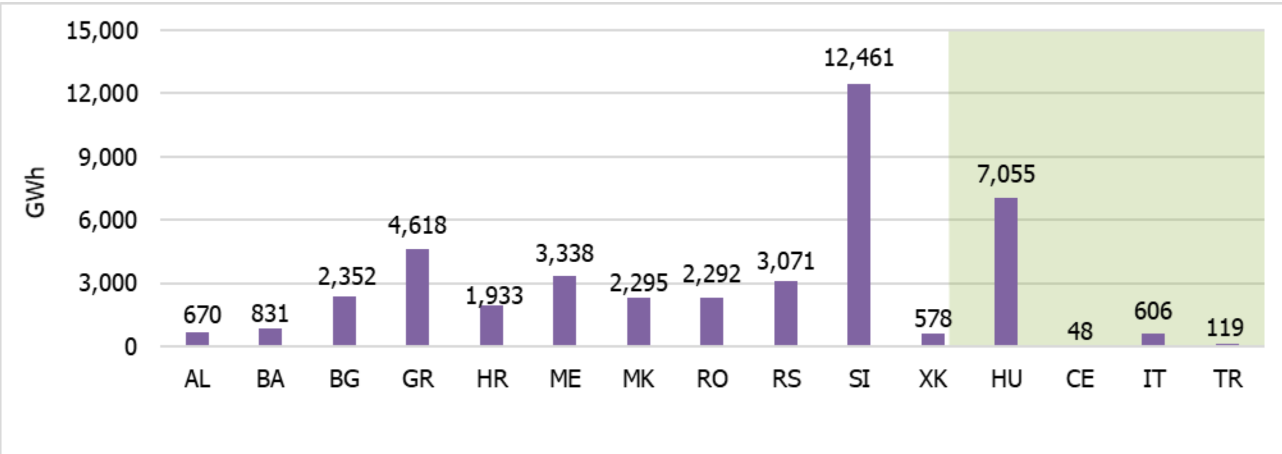


Figure 85: Transits in 2025 (High RES, low demand and dry hydrological conditions – SM)

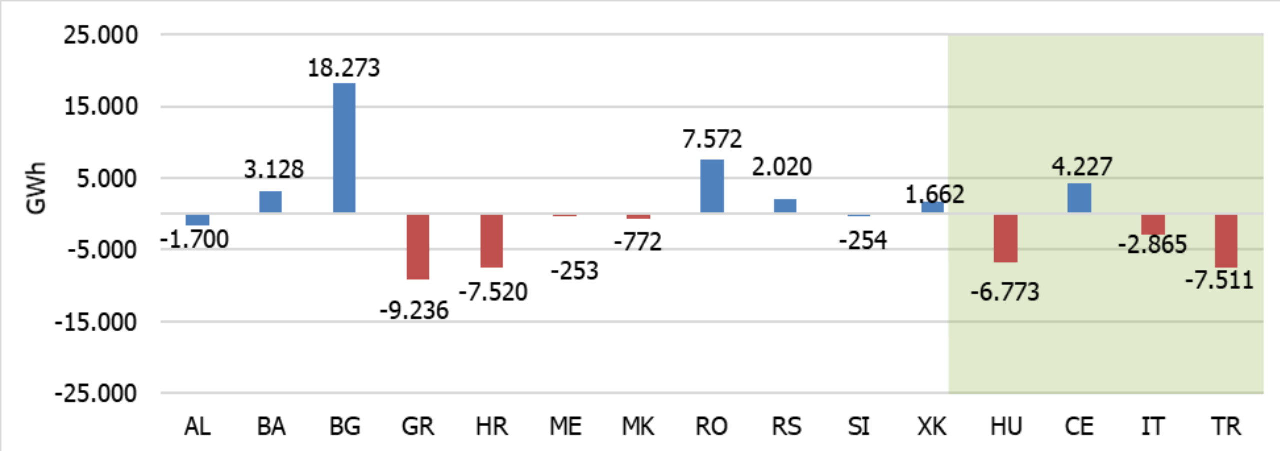


Figure 86: Net interchange in 2025 (High RES, low demand and dry hydrological conditions – SM)

When observing differences among the SEE market areas, the important factor is operating cost, for which we present yearly simulation results in Table 96. We determine the market price from the marginal cost of generation and the price in neighboring markets, and we base the calculation of operating costs on variable costs, including the fuel, CO_2 and O&M cost of generating units.

In these market conditions, the average operating costs in the SEE region amount to 12.69 €/MWh. The highest average operating cost is in the MEPSO market area (15.42 €/MWh) where TPPs have a high share (second only to the share in the KOSTT area). Table 96 also presents data on yearly CO_2 emissions in the SEE region. The highest CO_2 emissions are in the EMS, TransElectrica and ESO EAD market areas. The average total operating costs, which include carbon costs, amount to 25.58 €/MWh in the SEE region. In terms of the average total operating cost, the KOSTT market area has the highest value (36.00 €/MWh) followed by the MEPSO market area (35.18 €/MWh). This is due to the carbon cost, which mostly affects market areas with a high share of coal TPPs.

In this scenario, the average SEE regional wholesale market price is 51.64 €/MWh. Generally, wholesale electricity prices are harmonized in the region, but we note certain variations. The HOPS, ELES and ADMIE/IPTO market areas have somewhat higher average wholesale prices than the rest of the modelled SEE region. The highest average price is in the HOPS market area (56.05 €/MWh), while the lowest is in the ESO EAD market area (50.12 €/MWh).

Table 96: Operating costs in 2025 (High RES, low demand and dry hydrological conditions – SM)

Operating costs without and with emissions costs	AL	BA	BG	GR	HR	ME	MK	RO	RS	SI	XK	SEE
Operating costs (mil. €)	0	162	812	696	108	23	111	905	393	160	91	**3,461**
CO_2 emissions (mil. tonne)	0	13	26	22	2	1	6	28	28	5	6	**137**
CO_2 emissions costs (mil. €)	0	332	665	569	54	38	143	710	709	130	165	**3,514**
Total operating costs (mil. €)	0	494	1,477	1,265	163	61	254	1,615	1,101	289	256	**6,975**
Average operating costs (€/MWh)	0.00	10.04	15.18	14.57	8.82	6.08	15.42	13.80	10.27	10.61	12.74	**12.69**
Average total operating costs (€/MWh)	0.00	30.59	27.62	26.47	13.25	16.19	35.18	24.62	28.79	19.25	36.00	**25.58**
Price (€/MWh)	52,32	51,44	50,12	53,96	56,05	51,67	51,25	50,15	50,63	55,51	51,40	**52,03**

We analyze yearly cross-border exchange, loading and congestions results below.

The ELES market area has the highest cross-border exchange (Table 97) (i.e., 26,970 GWh (13,358 GWh of exports, including transits, towards neighboring market areas and 13,612 GWh of imports, including transits, in the opposite direction). The KOSTT market area has the lowest yearly cross-border exchange in the SEE region, 3,285 GWh (2,473 GWh of exports, including transits, towards neighboring market areas, and 811 GWh of imports, including transits, in the opposite direction). When analyzing flows per border, we note the highest yearly flow on the BG-GR border, especially from the ESO EAD market area to the ADMIE/IPTO market area, showing that imports to the ADMIE/IPTO market area mostly come from the ESO EAD market area.

Table 97: Cross-border exchange in 2025 (High RES, low demand and dry hydrological conditions – SM)

Market area	Flow (GWh)														
	AL	BA	BG	GR	HR	HU	ME	MK	RO	RS	SI	XK	CE	IT	TR
AL	-			397			641	172				98			
BA		-			3,101		934			325					
BG			-	9,961				1,700	1,915	788					6,262
GR	214		0	-				289						1,905	2,453
HR		187			-	314				46	1,687				
HU					2,226	-			352	179	2,617		2,002		
ME	703	298					-			81		223		2,633	
MK	811		6	1,556				-		63		76			
RO			1,640			6,354			-	1,992					
RS		747	186		1,457	1,477	564	673	146	-		415			
SI					2,969	2,214					-		2,302	5,872	
XK	1,280						571	450		172		-			
CE						3,789					4,742		-		
IT				1,499			1,480				4,566			-	
TR			521	683											-

We provide yearly average cross-border loadings in Table 98. Cells in red show high flows (i.e., above 50%), while cells in green show low flows (i.e., below 10%). In this scenario the highest cross-border loading values occur on the BG-GR border (84%, towards the ADMIE/IPTO market area), which is consistent with the high flows on that border shown in the previous table. High loadings also occur on BG-TR border (80%, towards Turkey). Generally, almost all links to the ADMIE/IPTO market area and Turkey are highly loaded. The TransElectrica market area's cross-border lines have notably low loading values in the direction of the TransElectrica market area (range 4-18%), and are significantly higher in the opposite direction (up to 66%), which confirms the TransElectrica market area as a significant exporter of electricity.

Table 98: Cross-border loading in 2025 (High RES, low demand and dry hydrological conditions – SM)

Market area	Loading (%)														
	AL	**BA**	**BG**	**GR**	**HR**	**HU**	**ME**	**MK**	**RO**	**RS**	**SI**	**XK**	**CE**	**IT**	**TR**
AL	-			36			29	10				4			
BA		-			63		36			12					
BG			-	84				78	18	45					80
GR	20		0	-				8						44	70
HR		4			-	4				2	15				
HU					21	-			4	7	25		29		
ME	32	11					-			6		17		50	
MK	31		0	43				-		7		9			
RO			17			66			-	46					
RS		29	11		67	56	43	47	4	-		32			
SI					26	21					-		28	42	
XK	47						44	32		10		-	0		
CE						54					57		-		
IT				34			28				32			-	
TR			12	18											-

We depict cross-border loadings in both directions (i.e., the sum of loadings in reference and counter-reference directions) in the following figure. The blue bars present borders that are coupled in all scenarios, while orange bars show borders coupled only in the PMC and the FMC scenarios. Thus, in this SM scenario, the borders shown in orange are not coupled.

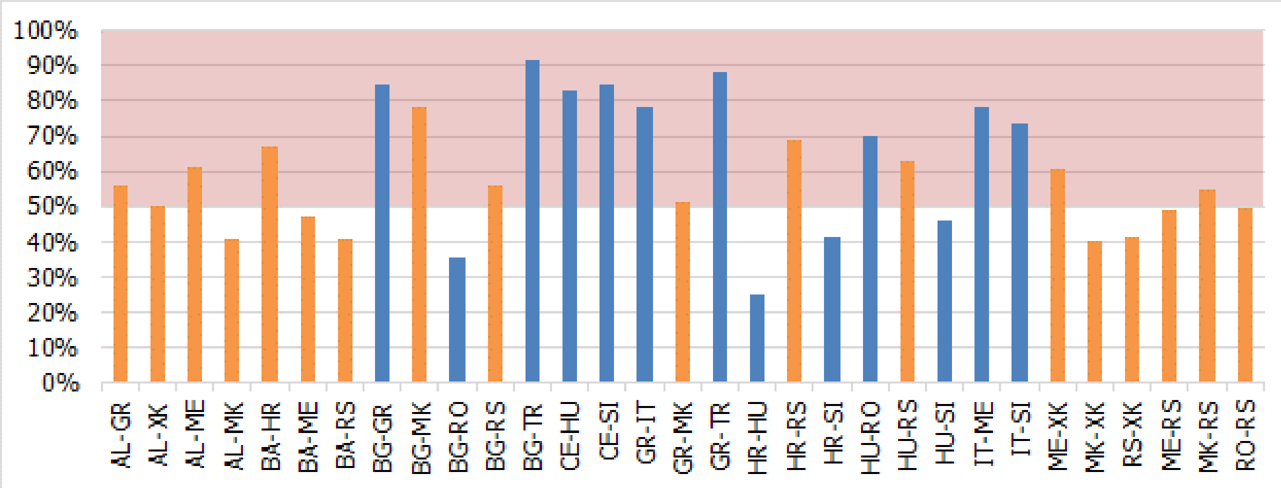


Figure 87: Cross-border loadings in both directions in 2025 (High RES, low demand and dry hydrological conditions – SM)

As Figure 87 shows, cross-border loadings in both directions range from 25% to 92% depending on the border. When analyzing borders on which we expect market couplings, we note high loadings in both directions (i.e. above 50%) on the AL-GR, AL-XK, AL-ME, BA-HR, BG-MK, BG-RS, GR-MK, HR-RS, HU-RS, ME-XK and MK-RS borders.

Cross-border congestions represent the number of hours in a year in which flows on interconnections equals or exceeds the modelled NTC. We present the cross-border congestion probability on each border in Table 99. Cells in red show high congestion probability (i.e.. above 50%), while cells in green show low congestion probability (i.e., below 10%). Significant congestion probabilities are notable, especially on the BG-TR and GR-TR borders, but only in one direction – towards the Turkish market. Other borders with high congestion probabilities are the BG-GR border (towards the ADMIE/IPTO market area) and the BG-MK border (towards the MEPSO market area).

Table 99: Cross-border congestion probability in 2025 (High RES, low demand and dry hydrological conditions – SM)

Market area	Congestion probability (%)														
	AL	BA	BG	GR	HR	HU	ME	MK	RO	RS	SI	XK	CE	IT	TR
AL	-			34			24	7				1			
BA		-			52		26			9					
BG			-	70				70	8	43					78
GR	19		0	-				4						43	69
HR		2			-	0				2	3				
HU					3	-			2	6	6		27		
ME	28	7					-			5		13		48	
MK	18		0	35				-		8		9			
RO			8			60			-	35					
RS		24	10		64	54	41	42	3	-		28			
SI					19	12					-		26	37	
XK	28						40	22		6		-	0		
CE						53					54		-		
IT				33			26				24			-	
TR			13	18											-

4.4.2 Partial market coupling (PMC)

We depict electricity generation and consumption in the SEE region for the PMC scenario in the case of high levels of RES penetration, low demand and dry hydrological conditions in Figure 88. Total generation in the SEE region in 2025 amounts to 274.87 TWh, while total consumption amounts to 259.93 TWh. The highest generation is in the TransElectrica market area, while as in other scenarios, the CGES market area has the lowest electricity generation.

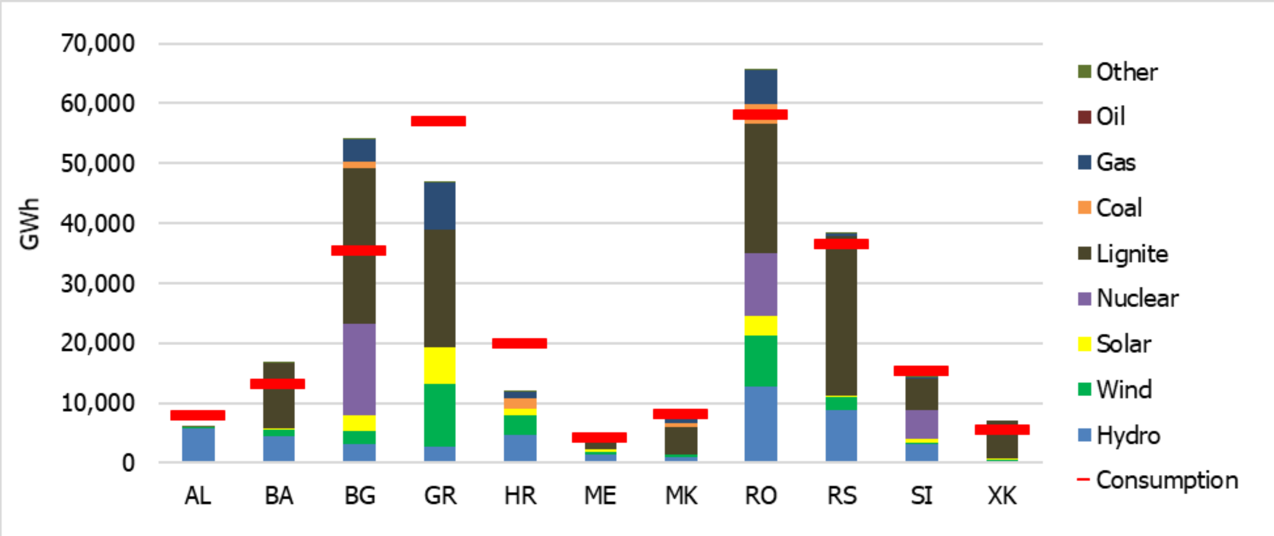


Figure 88: Electricity generation mix and consumption by market area in 2025 (High RES, low demand and dry hydrological conditions – PMC)

We present the electricity generation mix by market area in more detail in the following table.

Table 100: Electricity generation mix by market area in 2025 (High RES, low demand and dry hydrological conditions – PMC)

Yearly generation (TWh)	AL	BA	BG	GR	HR	ME	MK	RO	RS	SI	XK	SEE
HPP	5.65	4.69	3.49	3.10	4.87	1.45	1.03	12.71	9.23	3.75	0.13	**50.10**
TPP lignite	0.00	11.07	25.98	19.64	0.00	1.50	4.61	21.65	26.65	5.13	6.50	**122.73**
TPP coal	0.00	0.00	1.12	0.00	1.68	0.00	0.56	3.14	0.00	0.00	0.00	**6.50**
TPP gas	0.00	0.00	3.52	7.81	1.05	0.00	0.74	5.70	0.43	0.39	0.00	**19.63**
TPP oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	**0.00**
TPP other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.80	0.00	0.00	0.00	**0.80**
Nuclear	0.00	0.00	15.42	0.00	0.00	0.00	0.00	10.44	0.00	4.90	0.00	**30.76**
Solar	0.11	0.14	2.51	6.28	1.12	0.41	0.09	3.36	0.26	0.62	0.14	**15.03**
Wind	0.27	1.13	2.21	10.40	3.40	0.42	0.27	8.48	2.17	0.16	0.40	**29.31**
TOTAL	**6.03**	**17.02**	**54.25**	**47.24**	**12.12**	**3.78**	**7.30**	**66.28**	**38.73**	**14.96**	**7.16**	**274.87**

In most of the SEE market areas TPPs have the highest share, except in the OST and HOPS market areas where HPPs have the highest share. In the TransElectrica, ESO EAD and ELES market areas, nuclear electricity generation also has a high share (though less than TPPs). The least diversified generation mix is the KOSTT market area, where 90% of electricity generation comes from TPPs.

We give the electricity balances (i.e., yearly consumption, generation and exchange values) for each SEE market area in the PMC scenario in Table 101. The ESO EAD and TransElectrica market areas have the highest net interchange value, meaning they are the main net exporters in the SEE region, while the ADMIE/IPTO market area is a significant net importer. The sum of net interchange in the SEE region is not zero, since this model includes neighboring power systems (i.e., three external markets and Hungary) modelled on a technology level.

Table 101: Electricity balance in 2025 (High RES, low demand and dry hydrological conditions – PMC)

Electricity balance	Cons. (GWh)	Gener. (GWh)	Pump load (GWh)	Custom. load (GWh)	Imports (GWh)	Exports (GWh)	Transit (GWh)	Net inter-change (GWh)	Net import / export share (%)
AL	7,730	6,030	0	7,730	2,480	780	772	-1,700	-22.00%
BA	13,168	17,022	333	12,835	297	4,152	1264	3,854	29.27%
BG	35,235	54,254	475	34,760	0	19,019	2677	19,019	53.98%
GR	56,981	47,236	526	56,456	10,024	278	4691	-9,746	-17.10%
HR	19,747	12,118	348	19,400	7,805	176	3171	-7,630	-38.64%
ME	4,033	3,779	0	4,033	952	698	3408	-254	-6.30%
MK	7,988	7,302	0	7,988	1,005	319	3524	-686	-8.59%
RO	58,028	66,270	0	58,028	114	8,356	2094	8,242	14.20%
RS	36,359	38,732	564	35,795	541	2,913	3954	2,372	6.52%
SI	15,214	14,960	811	14,403	1,117	863	13213	-254	-1.67%
XK	5,449	7,163	0	5,449	231	1,945	795	1,714	31.45%
SEE	**259,934**	**274,865**	**3,056**	**256,879**	**24,567**	**39,498**	**39,563**	**14,930**	**5.74%**

Consumption in the table is calculated by adding the customer load (demand) and pump load for pumped storage HPPs, and subtracting energy not supplied (if it exists). Customer load is a predefined hourly input time series of demand. Pump load values change in scenarios based on the operation of pump storage HPPs in pumping mode.

Generation in this table refers to the total generation calculated by adding the generation of all modelled power plants, and subtracting the curtailed generation (if it exists).

We previously showed the yearly values for exports, imports, transits and net interchange for the SEE market areas in Table 75, but here we also show the neighboring power systems. Exports and imports values are depicted in Figure 89, transits in Figure 90 and net interchange in Figure 91. Exports are positive values, while imports are negative values. In the SEE region, the ADMIE/IPTO market area is the highest net importer, and the ESO EAD market area is the highest net exporter, as shown in Figure 91. Figure 90 shows that the highest power transit is through the ELES market area, based on the high import and export values. Regarding neighboring power systems, the highest power transit is through Hungary. While Hungary, Italy and Turkey mostly import electricity from the SEE region, Central Europe mostly exports electricity to the SEE region, which is expected due to the lower level of the wholesale market price in Central Europe compared to other neighboring markets (as presented in chapter 2.5).

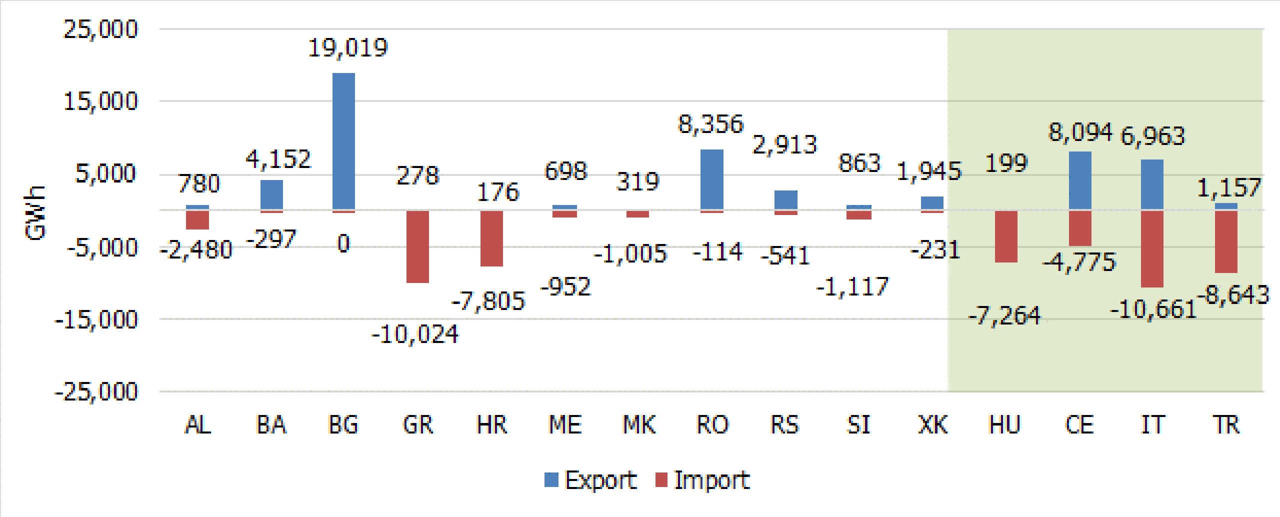


Figure 89: Imports and exports in 2025 (High RES, low demand and dry hydrological conditions – PMC)

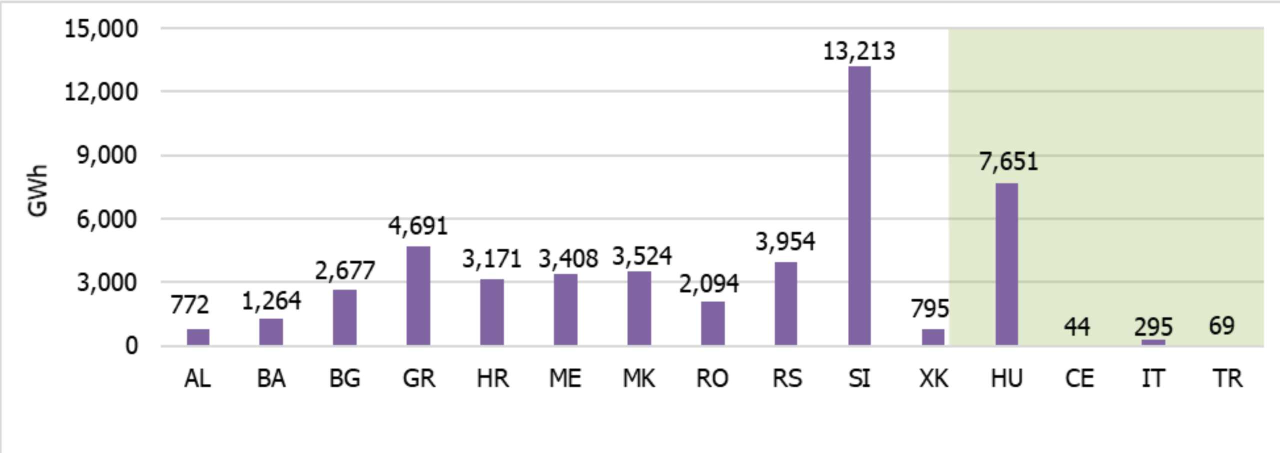


Figure 90: Transits in 2025 (High RES, low demand and dry hydrological conditions – PMC)

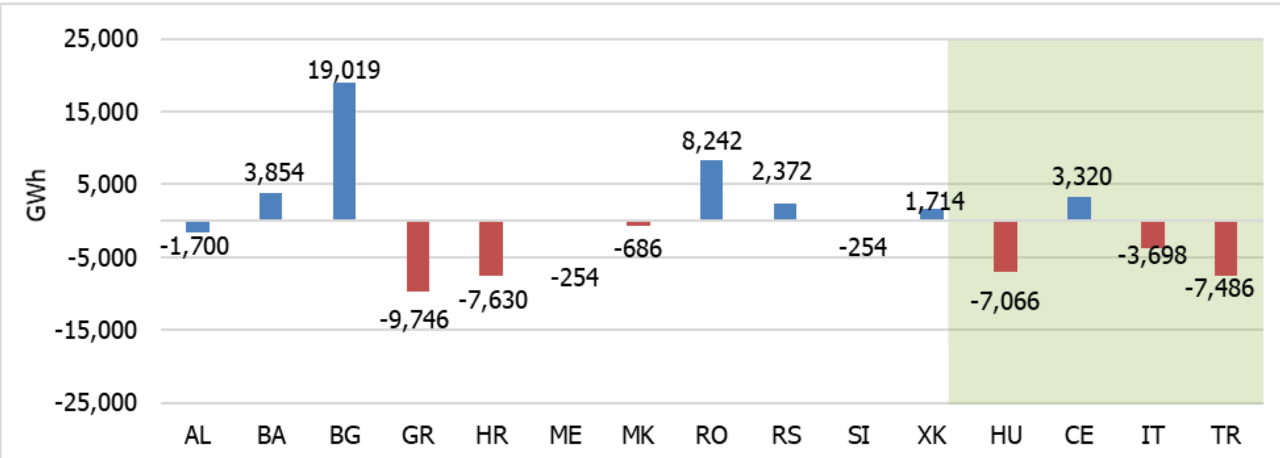


Figure 91: Net interchange in 2025 (High RES, low demand and dry hydrological conditions – PMC)

When there are differences among SEE market areas, the important factor for wholesale prices is operating cost, for which we present yearly simulation results in Table 102. Market price is determined by the marginal cost of generation and the price in neighboring markets, and the calculation of operating costs is based on variable costs, including fuel, CO_2 and the O&M cost of generating units.

In the PMC scenario, average operating costs in the SEE region amount to 12.77 €/MWh. The highest average operating cost is in the MEPSO market area (15.67 €/MWh) where TPPs have a high share. Table 102 also presents data about the yearly amount of CO_2 emissions in the SEE region. The highest level of CO_2 emissions are noted in the EMS, TransElectrica and ESO EAD market areas. Average total operating costs, which include also carbon costs, amount to 25.73 €/MWh in the SEE region. In terms of the average total operating cost, the KOSTT market area has the highest value (36.05 €/MWh) followed by the MEPSO market area (35.38 €/MWh).

In this scenario, the average SEE regional wholesale market price is 52.42 €/MWh. Generally, wholesale electricity prices are harmonized in the region, more than in the case of SM scenario, but still there are certain variations that can be noticed. The HOPS and ELES market areas have somewhat higher level of average wholesale prices than the rest of the modelled SEE region. The highest average price is in the HOPS market area (55.26 €/MWh), while the lowest is in the TransElectrica market area (50.84 €/MWh).

Table 102: Operating costs in 2025 (High RES, low demand and dry hydrological conditions – PMC)

Operating costs without and with emissions costs	AL	BA	BG	GR	HR	ME	MK	RO	RS	SI	XK	SEE
Operating costs (mil. €)	0	174	840	673	102	23	114	930	404	158	91	**3,510**
CO_2 emissions (mil. tonne)	0	14	26	22	2	1	6	28	28	5	6	**139**
CO_2 emissions costs (mil. €)	0	357	676	562	53	38	144	721	716	130	167	**3,564**
Total operating costs (mil. €)	0	531	1,516	1,236	155	61	258	1,650	1,120	288	258	**7,073**
Average operating costs (€/MWh)	0.00	10.24	15.48	14.25	8.42	6.07	15.67	14.03	10.42	10.59	12.75	**12.77**
Average total operating costs (€/MWh)	0.00	31.21	27.94	26.16	12.79	16.18	35.38	24.90	28.91	19.25	36.05	**25.73**
Price (€/MWh)	52.80	53.51	50.85	53.02	55.26	53.23	51.57	50.84	52.65	54.75	52.34	**52.42**

We analyze yearly cross-border exchange, loading and congestions results below.

The highest cross-border exchange in this scenario (see Table 103) are in the ELES market area i.e., 28,406 GWh (14,076 GWh of exports, including transits, from the ELES market area to neighboring areas, and 14,330 GWh of imports in the opposite direction). The KOSTT market area has the lowest yearly cross-border exchange in the SEE region, 3,766 GWh (2,740 GWh of exports from the KOSTT market area to neighboring areas, and 1,026 GWh of imports in the opposite direction). When analyzing individual border flows, we note the highest yearly flow on the BG-GR border, from the ESO EAD market area to the ADMIE/IPTO market area, showing that imports to the ADMIE/IPTO market area mostly come from the ESO EAD market area, as in the SM scenario.

Table 103: Cross-border exchange in 2025 (High RES, low demand and dry hydrological conditions – PMC)

Market area	Flow (GWh)														
	AL	BA	BG	GR	HR	HU	ME	MK	RO	RS	SI	XK	CE	IT	TR
AL	-			341			756	240				215			
BA		-			4,773		507			136					
BG			-	9,682				3,242	1,722	865					6,184
GR	239		0	-				189						2,012	2,528
HR		154			-	519				32	2,641				
HU					1,945	-			374	331	2,936		2,263		
ME	671	495					-			132		254		2,554	
MK	883		1	2,599				-		180		179			
RO			1,912			6,101			-	2,437					
RS		912	192		1,328	2,446	977	523	112	-		378			
SI					2,930	2,200					-		2,556	6,390	
XK	1,459						564	335		382		-			
CE						3,649					4,490		-		
IT				1,439			1,556				4,263			-	
TR			572	654											-

We show the yearly average cross-border loadings in Table 104. Cells in red show high flows (above 50%), while cells in green show low flows (below 10%). The highest cross-border loading values occur on the BG-GR border (82%, towards the ADMIE/IPTO market area) which is consistent with the high flows on that border. High loadings also occur on the BG-TR and GR-TR borders (79% and 72% respectively, towards Turkey). As in previous scenarios, the TransElectrica market area's cross-border lines have low loading values, towards the TransElectrica market area (4-16%), while significantly higher in the opposite direction (20-63%).

Table 104: Cross-border loading in 2025 (High RES, low demand and dry hydrological conditions – PMC)

Market area	Loading (%)														
	AL	BA	BG	GR	HR	HU	ME	MK	RO	RS	SI	XK	CE	IT	TR
AL	-			31			35	14				4			
BA		-			49		19			5					
BG			-	82				74	16	50					79
GR	22		0	-				3						46	72
HR		2			-	6				1	24				
HU					19	-			4	6	28		32		
ME	31	19					-			5		19		49	
MK	34		0	36				-		21		21			
RO			20			63			-	56					
RS		35	11		61	47	37	37	3	-		29			
SI					26	21					-		31	46	
XK	27						43	24		22		-	0		
CE						52					54		-		
IT				33			30				30			-	
TR			13	17											-

We depict cross-border loadings in both directions in the following figure. Blue bars present borders that are coupled in all scenarios; orange bars show borders that are not coupled in the PMC scenario, while green bars are borders that are coupled in the PMC scenario. In this PMC scenario, the six borders shown in green bars are coupled: AL-XK, BA-HR, BG-MK, GR-MK, HU-RS, ME-RS.

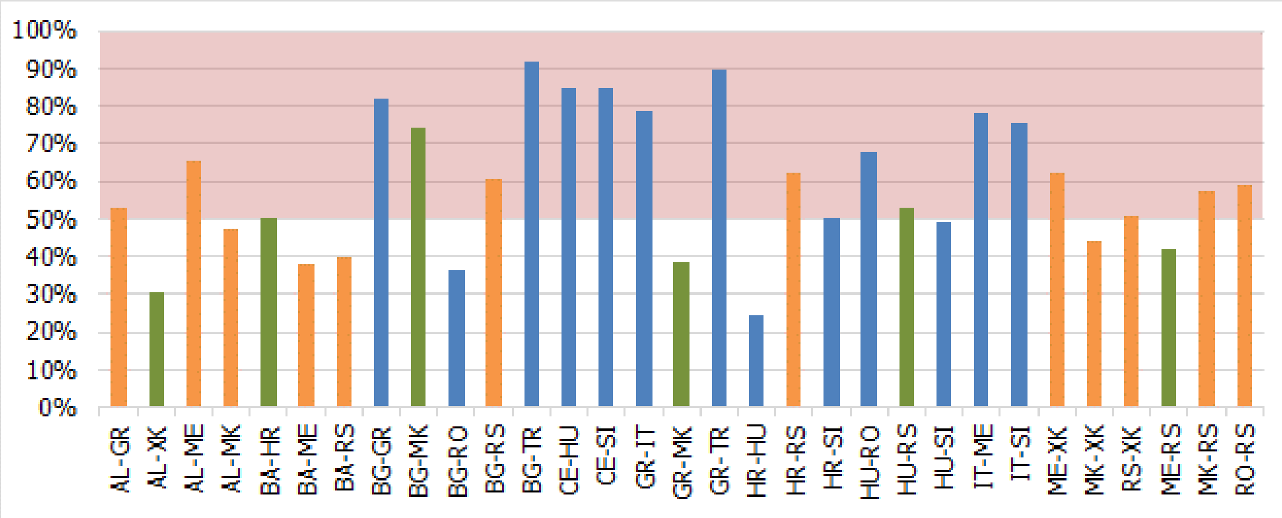


Figure 92: Cross-border loadings in both directions in 2025 (High RES, low demand and dry hydrological conditions – PMC)

As Figure 92 shows, cross-border loadings in both directions range from 25% to 92% depending on the border. When analyzing borders on which there are no market couplings in the PMC scenario, we note high loadings in both directions (i.e., above 50%) on the AL-GR, AL-ME, BG-RS, HR-RS, ME-XK, RS-XK, MK-RS and RO-RS borders.

Cross-border congestion is the number of hours in a year in 2025 in which we project that the flow on the interconnection equals or exceeds the NTC. We present the cross-border congestion probability for each border in Table 105. Cells in red have high congestion probability (i.e., above 50%), while cells in green have low congestion probability (i.e., below 10%). We note significant congestion probabilities, especially on the BG-TR and GR-TR border, but only in one direction – towards the Turkish market. Other borders with high congestion probabilities are the BG-GR border (towards the ADMIE/IPTO market area) and the RS-HR border (towards the HOPS market area).

Table 105: Cross-border congestion probability in 2025 (High RES, low demand and dry hydrological conditions – PMC)

Market area	Congestion probability (%)														
	AL	BA	BG	GR	HR	HU	ME	MK	RO	RS	SI	XK	CE	IT	TR
AL	-			30			31	12				0			
BA		-			27		13			4					
BG			-	67				56	7	48					77
GR	21		0	-				1						46	72
HR		0			-	1				1	10				
HU					3	-			2	3	8		31		
ME	27	12					-			2		16		47	
MK	25		0	21				-		22		20			
RO			10			56			-	47					
RS		28	10		57	40	32	32	2	-		27			
SI					20	12					-		30	42	
XK	1						39	18		18		-	0		
CE						51					51		-		
IT				32			28				23			-	
TR			14	17											-

4.4.3 Full market coupling (FMC)

We depict electricity generation and consumption in the SEE region for the FMC scenario in 2025 with high RES penetration, low demand, and dry hydrological conditions in Figure 93. Total generation in the SEE region in 2025 would amount to 275.68 TWh, while total consumption would reach 259.66 TWh. The highest generation will be in the TransElectrica market area, and the CGES market area would have the lowest electricity generation.

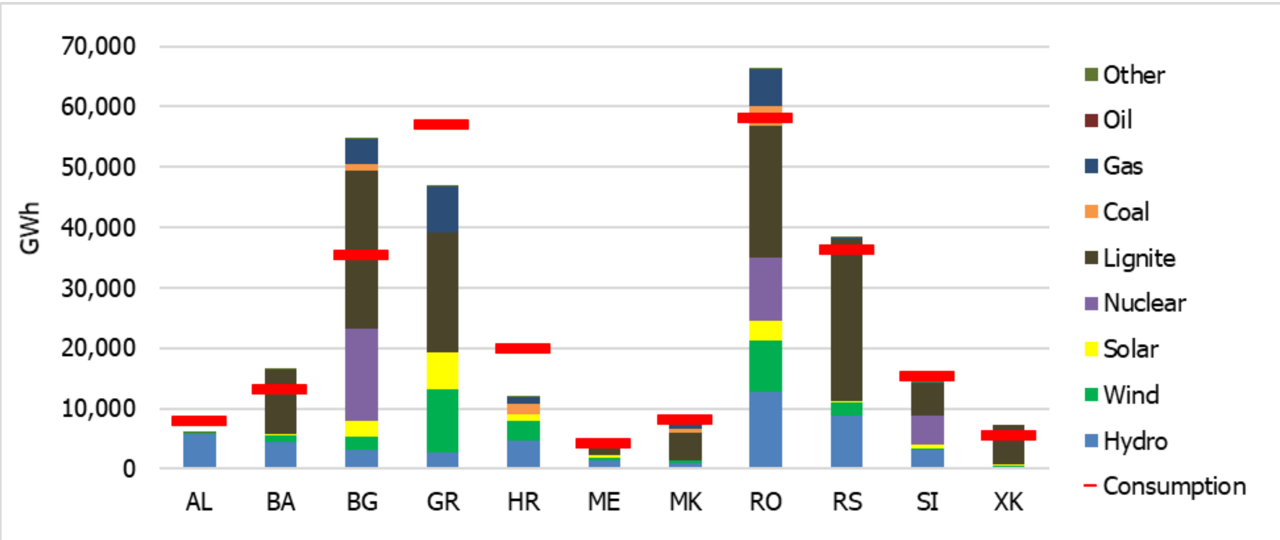


Figure 93: Electricity generation mix and consumption by market area in 2025 (High RES, low demand and dry hydrological conditions – FMC)

Electricity generation mix by market area is presented in more details in the following table.

Table 106: Electricity generation mix by market area in 2025 (High RES, low demand and dry hydrological conditions – FMC)

Yearly generation (TWh)	AL	BA	BG	GR	HR	ME	MK	RO	RS	SI	XK	SEE
HPP	5.65	4.62	3.51	3.09	4.86	1.45	1.03	12.71	9.13	3.73	0.13	**49.89**
TPP lignite	0.00	10.75	26.12	19.65	0.00	1.50	4.62	21.91	26.71	5.14	6.53	**122.94**
TPP coal	0.00	0.00	1.17	0.00	1.68	0.00	0.56	3.25	0.00	0.00	0.00	**6.66**
TPP gas	0.00	0.00	3.96	7.70	0.95	0.00	0.74	6.15	0.34	0.38	0.00	**20.23**
TPP oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	**0.00**
TPP other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.85	0.00	0.00	0.00	**0.85**
Nuclear	0.00	0.00	15.43	0.00	0.00	0.00	0.00	10.44	0.00	4.90	0.00	**30.77**
Solar	0.11	0.14	2.51	6.28	1.12	0.41	0.09	3.36	0.26	0.62	0.14	**15.03**
Wind	0.27	1.13	2.21	10.40	3.40	0.42	0.27	8.48	2.17	0.16	0.40	**29.31**
TOTAL	**6.03**	**16.63**	**54.92**	**47.12**	**12.01**	**3.78**	**7.31**	**67.15**	**38.61**	**14.93**	**7.19**	**275.68**

In most of the SEE market areas, TPPs have the highest share, except in the OST and HOPS market areas where HPPs have the highest share, and except in the TransElectrica and ELES market areas where nuclear electricity generation is the highest share. The least diversified generation mix is in the KOSTT market area, where 90% of electricity generation comes from TPPs.

We provide electricity balances (i.e., yearly consumption, generation and exchange values) for each SEE market area in the FMC scenario in Table 107. The ESO EAD and TransElectrica market areas have the highest net interchange, meaning that they are the main net exporters in the SEE region, while the ADMIE/IPTO market area is a significant net importer, as in the SM and PMC scenarios. As mentioned, the sum of net interchange in the SEE region is not zero, since this model includes neighboring systems (i.e., three external markets and Hungary) modelled on a technology level.

Table 107: Electricity balance in 2025 (High RES, low demand and dry hydrological conditions – FMC)

Electricity balance	Cons. (GWh)	Gener. (GWh)	Pump load (GWh)	Custom. load (GWh)	Imports (GWh)	Exports (GWh)	Transit (GWh)	Net inter-change (GWh)	Net import / export share (%)
AL	7,730	6,030	0	7,730	2,668	968	891	-1,700	-22.00%
BA	13,071	16,628	236	12,835	355	3,912	1,865	3,557	27.22%
BG	35,259	54,921	499	34,760	0	19,662	2,383	19,662	55.77%
GR	56,965	47,120	509	56,456	10,278	433	4,761	-9,845	-17.28%
HR	19,727	12,006	328	19,400	7,836	114	4,091	-7,722	-39.14%
ME	4,033	3,778	0	4,033	918	663	3,876	-255	-6.33%
MK	7,988	7,313	0	7,988	1,040	365	3,730	-675	-8.45%
RO	58,028	67,143	0	58,028	112	9,227	2,175	9,115	15.71%
RS	36,224	38,607	429	35,795	589	2,972	6,215	2,383	6.58%
SI	15,183	14,934	780	14,403	1,103	853	13,665	-250	-1.64%
XK	5,449	7,194	0	5,449	232	1,977	722	1,745	32.02%
SEE	**259,659**	**275,674**	**2,780**	**256,879**	**25,133**	**41,147**	**44,374**	**16,014**	**6.17%**

Consumption in the table above refers to the total consumption calculated by adding customer load (demand) and pumped load for pumped storage HPPs, and subtracting the energy not supplied (if any). Customer load is a predefined hourly input time series of demand. Pumped load values change in these scenarios based on the operation of pumped storage HPPs in pumping mode.

Generation in the table refers to the total generation calculated by adding the generation of all modelled power plants, and subtracting curtailed generation (if any).

We previously showed yearly values for exports, imports, transits and net interchange for the SEE market areas in Table 81, but we depict them here for neighboring power systems as well. We show export and import values in Figure 94, transits in Figure 95, and net interchange in Figure 96. Exports are positive values, while imports are negative. In the SEE region, the ADMIE/IPTO market area is the highest net importer, and the ESO EAD market area is by far the highest net exporter, as shown in Figure 96. Figure 95 shows that by far the highest power transit is through ELES, as in the SM and PMC scenarios. On neighboring systems, by far the highest power transit is through Hungary. While Hungary, Italy and Turkey mostly import electricity from SEE, Central Europe mostly exports electricity to the SEE region, as expected, considering the lower level of assumed wholesale market prices in Central Europe, compared to other neighboring markets (as presented in chapter 2.5).

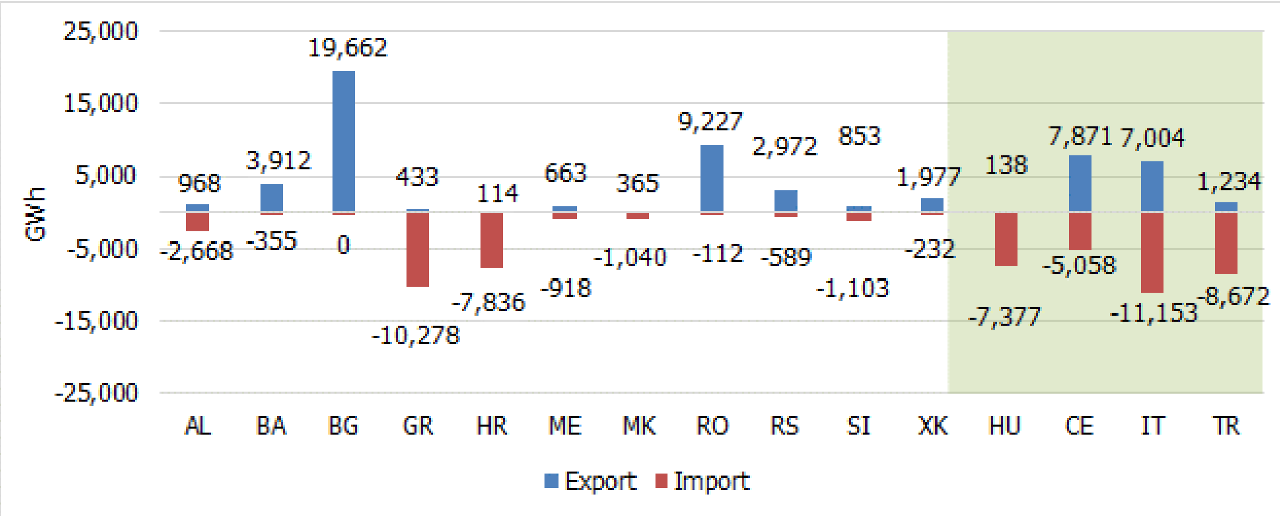


Figure 94: Imports and exports in 2025 (High RES, low demand and dry hydrological conditions – FMC)

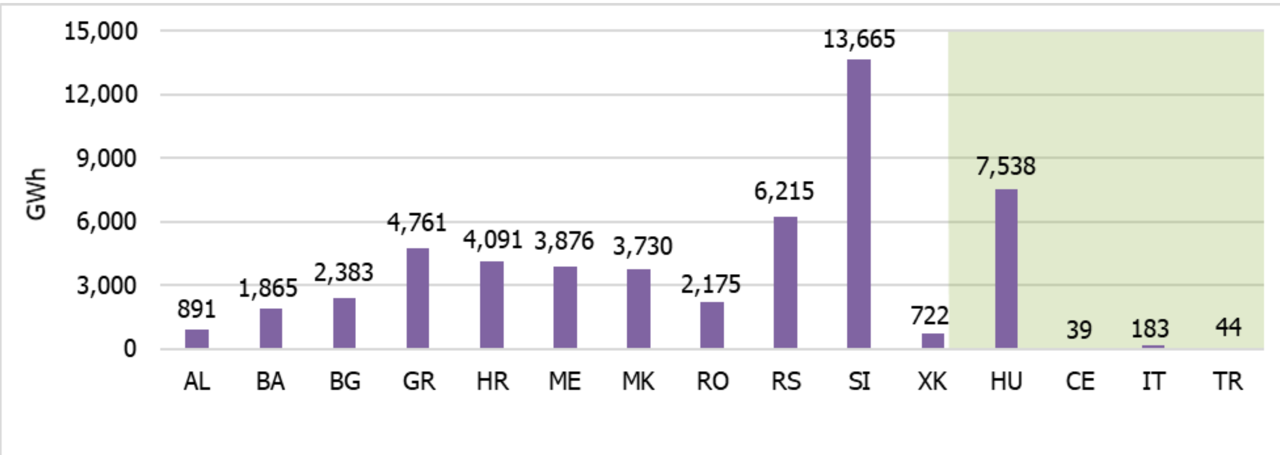


Figure 95: Transits in 2025 (High RES, low demand and dry hydrological conditions – FMC)

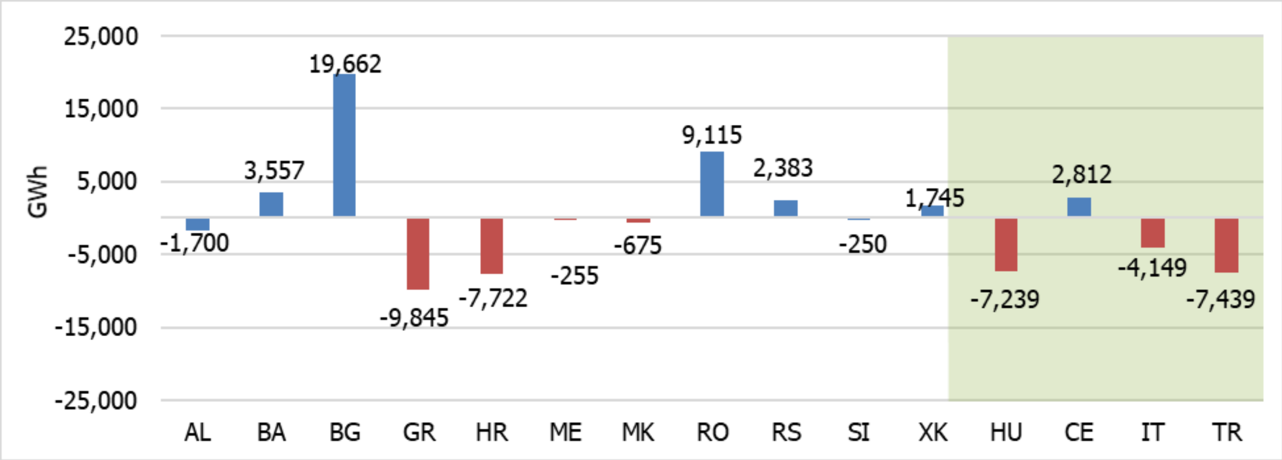


Figure 96: Net interchange in 2025 (High RES, low demand and dry hydrological conditions – FMC)

There are important differences among the SEE market areas on operating costs, for which we present yearly simulation results in Table 108. The market price is determined by the marginal cost of generation and the price in neighboring markets, and the calculation of operating costs is based on variable costs, including fuel, CO_2 and the O&M cost of generating units.

In this scenario, the average regional operating costs in the SEE region are 12.87 €/MWh. The highest average operating cost is in the ESO EAD market area (15.75 €/MWh) where TPPs have a high share, closely followed by the MEPSO market area (15.70 €/MWh). Table 108 also presents data on yearly regional CO_2 emissions. The highest CO_2 emissions would be in the TransElectrica market area, closely followed by the EMS and ESO EAD market areas. Average total operating costs, including carbon costs, amount to 25.84 €/MWh. In terms of the average total operating cost, the KOSTT market area is highest (36.07 €/MWh) followed by the MEPSO market area (35.40 €/MWh), due to carbon costs affecting market areas with a high share of coal TPPs.

In this scenario, the average SEE regional wholesale market price is 52.40 €/MWh. Generally, wholesale electricity prices are harmonized in the region, even more than in the PMC scenario, but there are still variations. The HOPS and ELES market areas are somewhat higher than the rest of the modelled SEE region. The highest average price is in the HOPS market area (54.86 €/MWh), followed by ELES (54.35 €/MWh), while the lowest is in the ESO EAD market area (51.54 €/MWh), which is close to the Transelectrica (51.64 €/MWh) and EMS (51.76 €/MWh) market areas.

Table 108: Operating costs in 2025 (High RES, low demand and dry hydrological conditions – FMC)

Operating costs without and with emissions costs	AL	BA	BG	GR	HR	ME	MK	RO	RS	SI	XK	SEE
Operating costs (mil. €)	0	169	865	668	97	23	115	960	400	158	92	**3,547**
CO_2 emissions (mil. tonne)	0	13	27	22	2	1	6	29	28	5	7	**139**
CO_2 emissions costs (mil. €)	0	346	685	562	52	38	144	734	717	130	168	**3,576**
Total operating costs (mil. €)	0	516	1,550	1,230	149	61	259	1,695	1,117	288	260	**7,123**
Average operating costs (€/MWh)	0.00	10.18	15.75	14.18	8.06	6.07	15.70	14.30	10.37	10.58	12.76	**12.87**
Average total operating costs (€/MWh)	0.00	31.01	28.22	26.10	12.40	16.17	35.40	25.24	28.94	19.26	36.07	**25.84**
Price (€/MWh)	52.45	52.25	51.54	52.95	54.86	52.04	51.62	51.64	51.76	54.35	52.00	**52.40**

We analyze yearly cross-border exchanges, loading and congestions results below.

In this scenario, the highest cross-border exchange (Table 109) is in the ELES market area (i.e., 29,285 GWh, with 14,518 GWh of exports from the ELES market area to neighboring areas and 14,768 GWh of imports in the opposite direction). The KOSTT market area has the lowest yearly cross-border exchanges, i.e., 3,352 GWh, with 2,699 GWh of exports from the KOSTT area to neighboring ones, and 954 GWh of imports in the opposite direction). On individual border flows, e the highest yearly flow is on the BG-GR border, mostly from the ESO EAD market area to the ADMIE/IPTO market area. Imports to the ADMIE/IPTO market area mostly come from the ESO EAD market area in the FMC scenario, as in the SM and PMC scenarios.

Table 109: Cross-border exchange in 2025 (High RES, low demand and dry hydrological conditions – FMC)

Market area	Flow (GWh)														
	AL	BA	BG	GR	HR	HU	ME	MK	RO	RS	SI	XK	CE	IT	TR
AL	-			724			840	211				84			
BA		-			4,878		738			161					
BG			-	9,464				2,875	1,909	1,655					6,142
GR	306		1	-				268						2,045	2,574
HR		156			-	763				59	3,227				
HU					1,519	-			323	418	2,999		2,419		
ME	1,113	548					-			48		180		2,651	
MK	967		3	2,764				-		202		159			
RO			1,502			5,878			-	4,023					
RS		1,516	251		2,615	2,422	868	929	56	-		531			
SI					2,916	2,284					-		2,679	6,640	
XK	1,174						800	487		238		-			
CE						3,569					4,341		-		
IT				1,437			1,549				4,201			-	
TR			627	650											-

We provide yearly average cross-border loadings in Table 110. Cells in red have high flows (i.e., above 50%), while cells in green have low flows (i.e., below 10%). In this scenario, the highest cross-border loading values also occur on the BG-GR border (80%, towards the ADMIE/IPTO market area), consistent with the high flows shown there in the previous table. High loadings also occur on BG-TR border (78%, towards Turkey). Generally, links to the ADMIE/IPTO market area and Turkey are highly loaded, as in the SM and PMC scenarios. The TransElectrica market area's cross-border lines have notably low loading values towards their own market area (range 4-18%), while they are significantly higher in the opposite direction (range 16-61%), confirming the TransElectrica market area as a significant exporter of electricity in the FMC scenario as well.

Table 110: Cross-border loading in 2025 (High RES, low demand and dry hydrological conditions – FMC)

Market area	Loading (%)														
	AL	BA	BG	GR	HR	HU	ME	MK	RO	RS	SI	XK	CE	IT	TR
AL	-			33			19	6				2			
BA		-			50		14			3					
BG			-	80				66	18	47					78
GR	14		0	-				4						47	74
HR		2			-	9				1	30				
HU					14	-			4	8	29		35		
ME	25	10					-			2		7		51	
MK	18		0	38				-		12		9			
RO			16			61			-	46					
RS		29	7		60	46	33	33	1	-		20			
SI					26	22					-		32	48	
XK	21						31	17		7		-	0		
CE						51					52		-		
IT				33			30				29			-	
TR			14	17											-

We depict cross-border loadings in both directions (i.e., the sum of loadings in the reference and counter-reference directions) in the following figure. Blue bars are borders that are coupled in all scenarios, while green bars borders that are also coupled in this scenario. In this FMC scenario, all 18 borders shown in green bars are coupled.

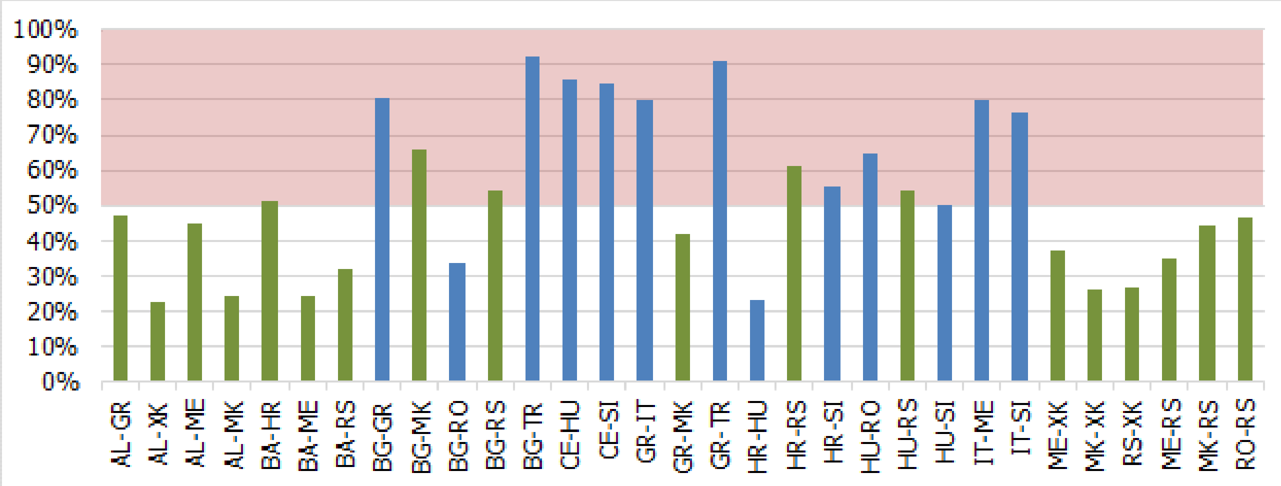


Figure 97: Cross-border loadings in both directions in 2025 (High RES, low demand and dry hydrological conditions – FMC)

As shown in Figure 97, cross-border loadings in both directions range from 23% to 92% depending on the border. When analyzing borders on which we modelled market couplings, we still note high loadings in both directions (i.e. loadings above 50%) on the BA-HR, BG-MK, BG-RS, HR-RS and HU-RS borders, but as expected, such loadings are significantly lower than in the SM scenario.

Cross-border congestion is the number of hours in a year in which interconnection flows equal or exceed the modelled NTC. We present the cross-border congestion probability for each border in Table 111. Cells in red show high congestion probability (i.e., above 50%), while cells in green are low (i.e., below 10%). There are significant congestion probabilities, especially on the BG-TR and GR-TR border, but only in one direction – towards Turkey. There is also a high congestion probability on the BG-GR border (towards the ADMIE/IPTO market area). When we assess borders in the SEE region which are coupled in this FMC scenario, and were not coupled in the SM scenario, we note a decrease of congestion probability.

Table 111: Cross-border congestion probability in 2025 (High RES, low demand and dry hydrological conditions – FMC)

Market area	Congestion probability (%)														
	AL	BA	BG	GR	HR	HU	ME	MK	RO	RS	SI	XK	CE	IT	TR
AL	-			30			11	3				0			
BA		-			35		4			1					
BG			-	64				49	8	43					77
GR	13		0	-				2						46	73
HR		0			-	2				1	15				
HU					1	-			2	5	8		33		
ME	15	3					-			1		3		50	
MK	7		0	26				-		11		8			
RO			6			53			-	27					
RS		15	5		54	42	26	26	0	-		14			
SI					22	13					-		31	44	
XK	2						20	8		2		-	0		
CE						51					50		-		
IT				32			29				23			-	
TR			15	17											-

4.4.4 Comparison of market coupling scenarios

We compare total electricity generation in the SEE region for different market coupling scenarios, in absolute values (TWh) as well as in percentages (%), in the following table. Generation refers to the total generation of all modelled power plants, minus curtailed generation (if any).

In the PMC scenario, total electricity generation rises by 2.16 TWh (0.79%), and in the FMC scenario by 2.97 TWh (1.09%) compared to the SM scenario. This increase is due to greater opportunities for electricity exports in integrated markets. In all scenarios, the highest generation is in the TransElectrica market area and the lowest in the CGES market area, but it is interesting to observe the effect of market coupling scenarios on specific market areas.

The most significant change in the PMC scenario occurs in the NOSBiH market area – yearly generation rises by 0.87 TWh (5.41%), while in the FMC scenario by 0.48 TWh (2.97%) compared to the SM scenario. In the FMC scenario, there is a high impact in TWhs of generation in the TransElectrica market area, where generation rises 1.54 TWh (2.35%) compared to the SM scenario. In some market areas there is no significant change (e.g., the OST and CGES market areas), since there is a lack of thermal power plants in those market areas which are able to increase generation.

Table 112: Comparison of electricity generation by market area in 2025 (High RES, low demand and dry hydrological conditions)

Yearly generation (TWh)	AL	BA	BG	GR	HR	ME	MK	RO	RS	SI	XK	SEE
Separated markets	6.03	16.15	53.48	47.78	12.28	3.78	7.22	65.60	38.25	15.04	7.11	**272.71**
Partial market coupling	6.03	17.02	54.25	47.24	12.12	3.78	7.30	66.27	38.73	14.96	7.16	**274.86**
Change (TWh)	0.00	0.87	0.78	-0.54	-0.16	0.00	0.09	0.67	0.48	-0.08	0.05	**2.16**
Change (%)	0.00	5.41	1.45	-1.13	-1.28	-0.03	1.19	1.02	1.26	-0.53	0.73	**0.79**
Full market coupling	6.03	16.63	54.92	47.12	12.01	3.78	7.31	67.14	38.61	14.93	7.19	**275.67**
Change (TWh)	0.00	0.48	1.44	-0.66	-0.27	0.00	0.10	1.54	0.36	-0.11	0.08	**2.97**
Change (%)	0.00	2.97	2.70	-1.37	-2.19	-0.07	1.34	2.35	0.93	-0.70	1.16	**1.09**

We compare yearly exports in Table 113, import values in Table 114, and transit values in Table 115. We should analyze these tables together with Figure 98.

In all scenarios, the ADMIE/IPTO and HOPS market areas are the highest electricity importers, while the ESO EAD and TransElectrica market areas are the highest exporters. The highest transit is always through the ELES market area.

In total, in the SEE region electricity exports increase 2,618 GWh (7.1%) in the PMC scenario and 4,267 GWh (11.6%) in the FMC scenario compared to the SM scenario. This is a significant change. The largest growth in exports in GWh would be in the NOSBiH market area in the PMC scenario, and in the TransElectrica market area in the FMC scenario, which is consistent with the increase of generation in those scenarios. When analyzing export changes across scenarios, the ADMIE/IPTO market area increases the most (up to 79%) in the FMC scenario, but the absolute level is small.

SEE regional electricity imports also increase meaningfully with market integration – in the PMC scenario by 609 GWh (2.5%) and in the FMC scenario by 1,175 GWh (4.9%).

Table 113: Comparison of export by market area in 2025 (High RES, low demand and dry hydrological conditions)-

Export (GWh)	AL	BA	BG	GR	HR	ME	MK	RO	RS	SI	XK	SEE
Separated markets	637	3,529	18,273	242	301	600	217	7,694	2,595	897	1,895	**36,880**
Partial market coupling	780	4,152	19,019	278	176	698	319	8,356	2,913	863	1,945	**39,498**
Change (GWh)	143	623	746	36	-125	98	102	662	318	-34	49	**2,618**
Change (%)	22.39	17.65	4.08	15.01	-41.62	16.35	47.17	8.61	12.27	-3.84	2.60	**7.1**
Full market coupling	968	3,912	19,662	433	114	663	365	9,227	2,972	853	1,977	**41,147**
Change (GWh)	331	383	1,389	191	-186	63	148	1,534	377	-45	82	**4,267**
Change (%)	51.95	10.86	7.60	79.03	-61.95	10.58	68.38	19.93	14.54	-4.97	4.30	**11.6**

Table 114: Comparison of import by market area in 2025 (High RES, low demand and dry hydrological conditions)

Import (GWh)	AL	BA	BG	GR	HR	ME	MK	RO	RS	SI	XK	SEE
Separated markets	2,337	401	0	9,477	7,821	852	989	121	575	1,151	233	**23,958**
Partial market coupling	2,480	297	0	10,024	7,805	952	1,005	114	541	1,117	231	**24,567**
Change (GWh)	143	-103	0	546	-15	99	16	-7	-34	-34	-2	**609**
Change (%)	6.10	-25.81	0.00	5.77	-0.20	11.65	1.66	-5.81	-5.85	-2.94	-0.93	**2.5**
Full market coupling	2,668	355	0	10,278	7,836	918	1,040	112	589	1,103	232	**25,133**
Change (GWh)	331	-46	0	801	16	66	52	-9	14	-49	-1	**1,175**
Change (%)	14.15	-11.50	N/A	8.45	0.20	7.76	5.23	-7.33	2.51	-4.22	-0.50	**4.9**

Figure 98 depicts comparison of yearly exports and imports for different market coupling scenarios.

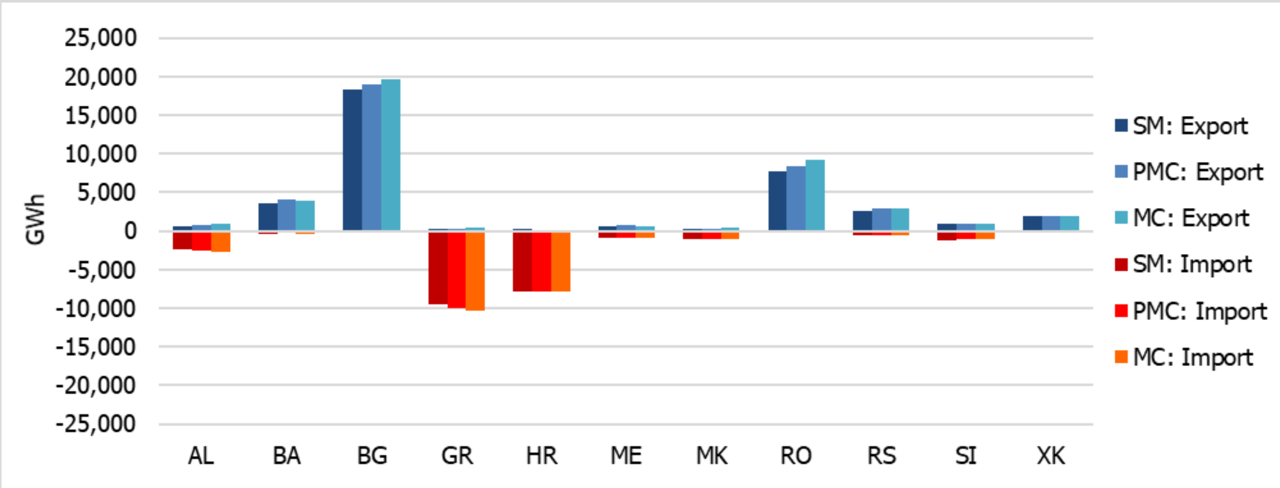


Figure 98: Comparison of exports and imports in 2025 (High RES, low demand and dry hydrological conditions)

Based on these exchange comparisons, we make several conclusions. First, on the regional level, the growth in exports is higher than imports, which in sum leads to greater net exchange in the PMC and FMC scenarios, compared with SM. As markets integrate, the region as whole exports more than before coupling, as transmission utilization is greater and supports more exports of lower-cost electricity to neighboring power systems, such as Hungary, Turkey and Italy. Second, when comparing individual countries in the coupling scenarios, all market areas increase exports, while only few increase imports. This is logical, given that coupling allows both better utilization of transmission capacities, and unlocks generation in the exporting areas.

Also, Table 115 shows that in both the PMC and FMC cases, regional transits change notably compared with the SM situation (almost 15% and 29%, respectively). Since transits represent flows of electricity through one system as a result of energy exchanges between two other systems, it is clear that market integration substantially boosts energy exchanges and flows across the SEE region.

Table 115: Comparison of transit by market area in 2025 (High RES, low demand and dry hydrological conditions)

Transit (GWh)	AL	BA	BG	GR	HR	ME	MK	RO	RS	SI	XK	SEE
Separated markets	670	831	2,352	4,618	1,933	3,338	2,295	2,292	3,071	12,461	578	**34,439**
Partial market coupling	772	1,264	2,677	4,691	3,171	3,408	3,524	2,094	3,954	13,213	795	**39,563**
Change (GWh)	102	433	325	73	1,238	70	1,229	-198	883	752	217	**5,124**
Change (%)	15.22	52.11	13.82	1.58	64.05	2.10	53.55	-8.64	28.75	6.03	37.54	**14.88**
Full market coupling	891	1,865	2,383	4,761	4,091	3,876	3,730	2,175	6,215	13,665	722	**44,374**
Change (GWh)	221	1,034	31	143	2,158	538	1,435	-117	3,144	1,204	144	**9,935**
Change (%)	32.99	124.43	1.32	3.10	111.64	16.12	62.53	-5.10	102.38	9.66	24.91	**28.85**

As mentioned, imports in GWh do not increase as much as exports, so in total the SEE region becomes a higher net exporter in the PMC and FMC scenarios. This is shown through analyzing net interchange values, as shown in Table 116. As mentioned, net interchange is the difference between exports and imports, so positive net interchange value means the market area is a net exporter.

In total, in the SEE region net interchange rises by 2,009 GWh in the PMC scenario and by 3,093 GWh in the FMC scenario, compared to the SM scenario. Generally, the ESO EAD market area has the highest positive net interchange in all scenarios. Increases in net interchange are especially visible in market areas with increased transmission capacities for commercial exchange due to market coupling, especially in the NOSBiH, ESO EAD and TransElectrica market areas. For example, net interchange of the ESO EAD market area rises substantially, by 746 GWh in the PMC scenario and by 1,389 GWh in the FMC scenario, compared to the SM scenario.

Table 116: Comparison of net interchange by market area in 2025 (High RES, low demand and dry hydrological conditions)

Net interchange (GWh)	AL	BA	BG	GR	HR	ME	MK	RO	RS	SI	XK	SEE
Separated markets	-1,700	3,128	18,273	-9,236	-7,520	-253	-772	7,572	2,020	-254	1,662	**12,922**
Partial market coupling	-1,700	3,854	19,019	-9,746	-7,630	-254	-686	8,242	2,372	-254	1,714	**14,930**
Change (GWh)	0	726	746	-510	-110	-1	86	669	352	-1	52	**2,009**
Full market coupling	-1,700	3,557	19,662	-9,845	-7,722	-255	-675	9,115	2,383	-250	1,745	**16,014**
Change (GWh)	0	429	1,389	-609	-202	-3	97	1,542	363	4	83	**3,093**

We depict the exchanges of Hungary, Italy, Turkey and Central Europe with the SEE region in the following figures for the SM, PMC and FMC scenarios (Figure 99 to Figure 101). The values in arrows present the exchange direction – blue arrows are exports from the SEE region to neighboring market area, and red arrows are import to the SEE region from neighboring market areas.

In all scenarios, the SEE region exports more electricity to neighboring market areas than it imports. As markets integrate, the SEE region becomes a stronger net exporter. Neighboring market areas import from the SEE region 29,749 GWh in the SM scenario, 31,343 GWh in the PMC scenario, and

42,261 GWh in the FMC scenario. At the same time, they export to the SEE region 16,827 GWh in the SM scenario, 16,413 GWh in the PMC scenario and 16,246 GWh in the FMC scenario.

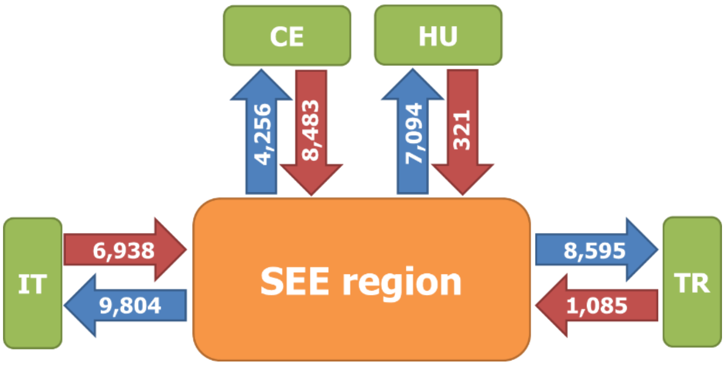


Figure 99: Hungary, Italy, Turkey, Central Europe and SEE regional exchange in 2025 (High RES, low demand and dry hydrological conditions – SM)

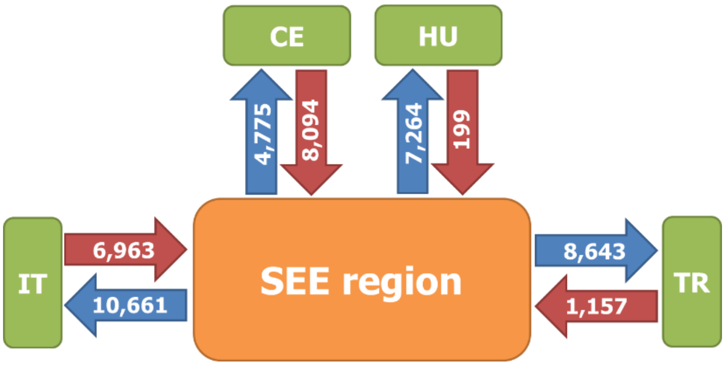


Figure 100: Hungary, Italy, Turkey, Central Europe and SEE regional exchange in 2025 (High RES, low demand and dry hydrological conditions – PMC)

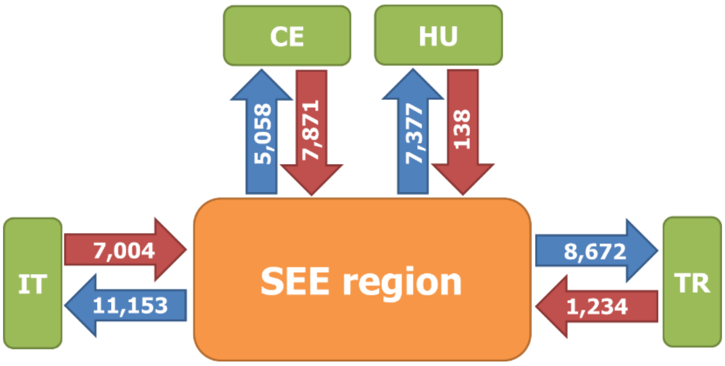


Figure 101: Hungary, Italy, Turkey, Central Europe and SEE regional exchange in 2025 (High RES, low demand and dry hydrological conditions – FMC)

We compare yearly net interchange values for different market coupling scenarios in Figure 102. In this comparison, we see that in all scenarios, the SEE region imports electricity on an annual basis from Central Europe, and exports electricity to Italy, Turkey and Hungary.

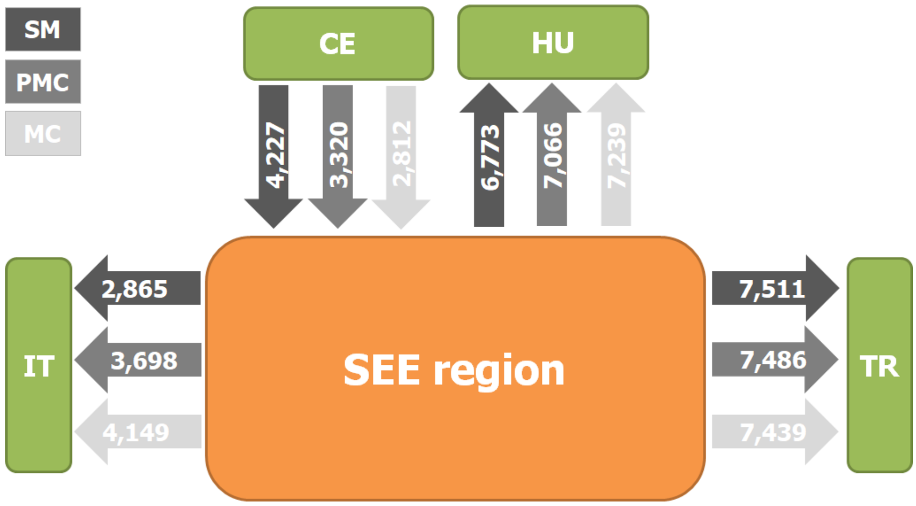


Figure 102: Hungary, Italy, Turkey, Central Europe and SEE regional net interchange in 2025 (High RES, low demand and dry hydrological conditions – comparison of the coupling scenarios)

In the market model, the market price is determined by the marginal cost of generation and the price in neighboring market areas. We present the resulting wholesale prices by market area in Table 117. The average wholesale market price in the SEE region is the load-weighted average of market areas in the SEE region. The average market price in the SEE region is 52.03 €/MWh in the separated markets scenario, 52.42 €/MWh with partial market coupling, and 52.40 €/MWh in the full market coupling scenario. Thus, the average SEE market price in PMC scenario is 0.39 €/MWh (0.76%) higher than in SM scenario, while in FMC scenario 0.37 €/MWh (0.72%) higher.

In a number of SEE market areas, average wholesale market prices increase a bit with market integration; however, in some market areas, prices fall in the PMC and FMC scenarios. In the ADMIE/IPTO, HOPS and ELES market areas in particular, wholesale prices are lower in the PMC and FMC scenarios. The biggest reduction in the PMC scenario is in the ADMIE/IPTO market area, where the market price is lower by 0.93 €/MWh, compared to the SM scenario. In the FMC scenario, the biggest drop occurs in the HOPS market area, where the price falls by 1.19 €/MWh, compared to the SM scenario. The most significant price increase in the PMC scenario occurs in the EMS and NOSBiH market areas, due to increased TPPs production in these market areas, and their coupling with market areas with higher market prices. In the FMC scenario, the wholesale market price also increases in the TransElectrica market area.

The increase in wholesale electricity prices, which occurs in the high RES, low demand and dry hydro circumstances, is primarily due to greater electricity generation in the SEE region, and higher exports to neighboring markets where prices are generally higher. Greater market integration enables greater transit of electricity through the SEE region and exports to external markets.

In the real markets, as we look not only to 2025, but beyond as well, we expect these modelled price increases (though the result of a sophisticated analysis) to be reduced and transitional, for the reasons described in the "Caveats" section of the Executive Summary. In particular, we believe that with greater market integration, wholesale power costs in all SEE markets could well decrease, SEWs will be higher, and that those benefits will grow larger over time.

Table 117: Comparison of average wholesale prices in 2025 by market area in 2025 (High RES, low demand and dry hydrological conditions)

Price (€/MWh)	AL	BA	BG	GR	HR	ME	MK	RO	RS	SI	XK	SEE	CV
Separated markets	52.32	51.44	50.12	53.96	56.05	51.67	51.25	50.15	50.63	55.51	51.40	**52.03**	**3.75%**
Partial market coupling	52.80	53.51	50.85	53.02	55.26	53.23	51.57	50.84	52.65	54.75	52.34	**52.42**	**2.55%**
Change (€/MWh)	0.48	2.07	0.73	-0.93	-0.80	1.56	0.32	0.69	2.02	-0.76	0.94	**0.39**	
Change (%)	0.92	4.03	1.45	-1.73	-1.42	3.01	0.63	1.37	4.00	-1.37	1.84	**0.76**	
Full market coupling	52.45	52.25	51.54	52.95	54.86	52.04	51.62	51.64	51.76	54.35	52.00	**52.40**	**2.05%**
Change (€/MWh)	0.13	0.81	1.41	-1.00	-1.19	0.36	0.37	1.48	1.13	-1.16	0.60	**0.37**	
Change (%)	0.24	1.58	2.82	-1.86	-2.12	0.71	0.72	2.96	2.23	-2.08	1.17	**0.72**	

We compare the average wholesale prices in different scenarios in Figure 103.

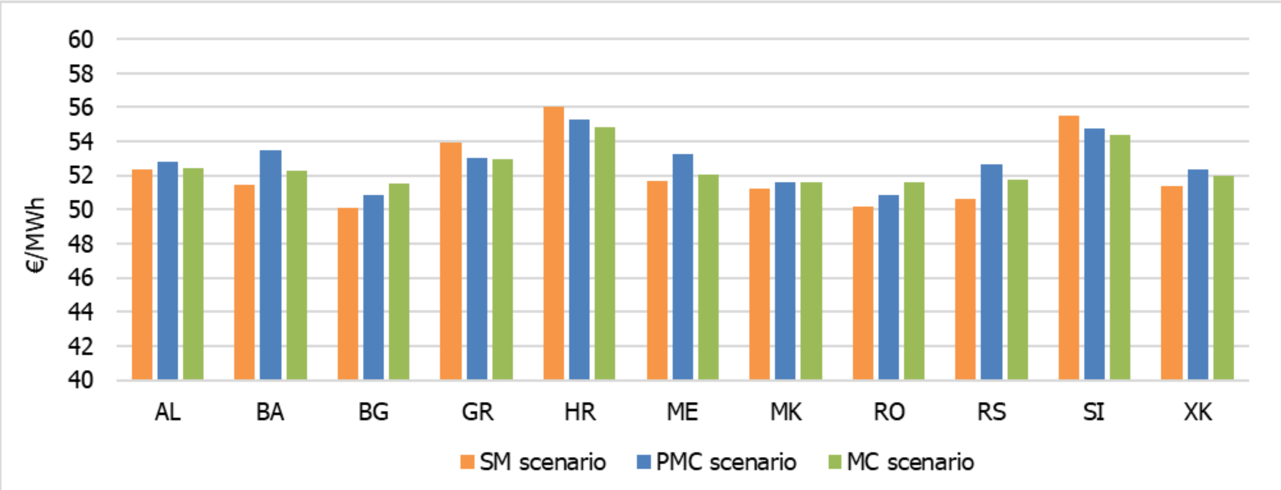


Figure 103: Comparison of average wholesale prices in 2025 (High RES, low demand and dry hydrological conditions)

After analyzing different market parameters, we calculate the change in social-economic welfare (SEW) in order to fully evaluate the overall benefits of regional market integration in the SEE region. SEW is measured as the change in consumer surplus, producer surplus and total congestion rents in the PMC and FMC scenarios compared to the SM scenario. We present the SEW in different market integration options for the EMI market areas in the following table.

Table 118: Comparison of socio-economic welfare in 2025 (High RES, low demand and dry hydrological conditions)

Market area	Partial market coupling - Separated markets				Full market coupling - Separated markets			
million €	Δ Producer surplus	Δ Consumer surplus	Δ Congestion rent	Δ Total surplus	Δ Producer surplus	Δ Consumer surplus	Δ Congestion rent	Δ Total surplus
AL	4.94	-3.71	-0.28	**0.95**	4.90	-0.97	-2.22	**1.71**
BA	36.63	-26.62	-3.72	**6.29**	15.05	-10.43	-0.49	**4.13**
BG	37.95	-25.22	-9.6	**3.13**	76.7	-49.15	-19.98	**7.57**
GR	-38.48	52.86	-14.05	**0.33**	-35.72	56.75	-19.47	**1.56**
HR	-15.48	15.47	-5.06	**-5.07**	-22.9	23.08	2.81	**2.99**
ME	7.96	-6.28	-2.22	**-0.54**	2.22	-1.47	-2.12	**-1.37**
MK	3.1	-2.57	-0.63	**-0.1**	4.14	-2.94	-3.77	**-2.57**
RO	45.2	-39.79	-3.7	**1.71**	100.84	-86.09	-13.63	**1.12**
RS	75.6	-72.46	0.53	**3.67**	45.13	-40.48	-2.37	**2.28**
SI	-10.57	10.96	7.34	**7.73**	-16.18	16.66	12.2	**12.68**
XK	7.26	-5.14	0.4	**2.52**	4.98	-3.27	-1.83	**-0.12**
TOTAL SEE	**154.1**	**-102.5**	**-30.99**	**20.61**	**179.17**	**-98.29**	**-50.86**	**30.02**

In this group of scenarios with high RES, low demand and dry hydrological conditions assumptions, the SEW for the SEE region in the PMC scenario amounts to 20.61 million €, while in the FMC scenario reaches 30.02 million €.

There are market areas with positive and negative change in SEW, which we do not believe should be considered as a negative signal for overall market coupling. In particular, there is a real question whether congestion rents should be included in the calculation of SEW at all, and if congestion rent is eliminated, there is no market area with a negative SEW (the HR market area is break-even).

In these scenarios, we expect the highest SEW benefits in the ELES and ESO EAD market areas. In the ELES market area this is mainly due to the increase in congestion rent expected after stronger market coupling in the SEE region. In the ESO EAD market area, higher exports with an increase in prices in the ESO EAD market area and small decrease in prices in the ADMIE/IPTO market area provides for positive changes in SEW. The NOSBiH market area also sees positive SEW, mainly due to a strong producer surplus.

In almost all market areas, market coupling leads to a decrease in congestion rents, as expected, since more cross-border capacities becomes available for market transactions with higher levels of market coupling. In some market areas, a decrease in congestion rents can lead to a negative total surplus, while in areas positioned between two distinctive price groups (like the ELES market area) there can be benefits from increased congestion rents. In most market areas, price convergence with more cross-border capacities leads to lower congestion rents for the TSOs.

On the other hand, as mentioned all market areas benefits from market coupling at the level of sum of producer and consumer surpluses. In exporting market areas, the benefits are more on producers' side, while in importing ones, on the consumers side, due to higher/lower prices, respectively. We present the sum of changes in producer and consumer surpluses in Table 119. In nearly all market areas this sum is positive, showing benefits from coupling for both producers and consumers.

Table 119: Comparison of the sum of changes in producer and consumer surpluses in 2025 (High RES, low demand and dry hydrological conditions)

Market area	Partial market coupling - Separated markets			Full market coupling - Separated markets		
million €	Δ Producer surplus	Δ Consumer surplus	Δ Sum	Δ Producer surplus	Δ Consumer surplus	Δ Sum
AL	4.94	-3.71	**1.23**	4.90	-0.97	**3.93**
BA	36.63	-26.62	**10.01**	15.05	-10.43	**4.62**
BG	37.95	-25.22	**12.73**	76.7	-49.15	**27.55**
GR	-38.48	52.86	**14.38**	-35.72	56.75	**21.03**
HR	-15.48	15.47	**-0.01**	-22.9	23.08	**0.18**
ME	7.96	-6.28	**1.68**	2.22	-1.47	**0.75**
MK	3.10	-2.57	**0.53**	4.14	-2.94	**1.20**
RO	45.20	-39.79	**5.41**	100.84	-86.09	**14.75**
RS	75.60	-72.46	**3.14**	45.13	-40.48	**4.65**
SI	-10.57	10.96	**0.39**	-16.18	16.66	**0.48**
XK	7.26	-5.14	**2.12**	4.98	-3.27	**1.71**
TOTAL SEE	154.10	-102.50	**51.60**	179.17	-98.29	**80.88**

Only in the HOPS market area, coupling with the NOSBIH market area in the PMC scenario reduces prices, but maintains a high level of internal generation, so the increase of consumer surplus is offset by a slightly larger decrease in producer surplus.

The "Caveats" section of the Executive Summary" provides more detail on why the SEW and other market benefits are likely to be greater, and the negative impacts to be transitory, compared to this model projection. Though the market model is highly sophisticated, it cannot capture all the dynamics of the real market, particularly as the level of coupling, private sector participation, and diversity of fuel and generation resources expand across the region.

5 IMPACTS OF REGIONAL MARKET INTEGRATION IN SEE

This chapter presents the main messages related to an overall regional perspective, and compares the main market coupling indicators for the four different Scenarios.

Exports and Imports. Through coupling of the market areas inside the SEE region, both total exports from and imports to the SEE region will increase, and the increase in exports will be higher. We conclude that in all scenarios, stronger market coupling enables higher net exchange (higher exports) between the SEE region and the rest of the world. This is for two reasons: the ability to utilize generation more efficiently across the region as coupling and market integration increase, and because coupling leads to greater utilization of the available net transmission capacity (NTC).

This increase in net exchange and exports is substantial compared to separated markets - between 19% and 61% depending on the scenario. Different development alternatives and operating conditions in the four sets of market conditions would produce a significantly different level of exports (see Table 120 and Figure 104):

- In separated markets: exports range from 3,6 TWh (in the Dry hydrology condition) to 18,7 TWh (the condition with high RES penetration and low demand);
- In fully coupled markets: exports range from 5,8 TWh (in the Dry hydrology condition) to 22,2 TWh (the condition with high RES penetration and low demand).

Different hydrological conditions significantly affects exports, as seen in the comparison between dry hydrology conditions (2nd and 4th scenarios) and the baseline and high level of RES penetration and low demand scenarios (1st and 3rd scenarios). Dry hydro conditions would reduce exports by 50%-60% in the reference case, and by around 30% in the high RES development and low demand case. Also, the high RES and low demand case makes much more generation available for export, and practically doubles interchange over the baseline in all scenarios. In addition, full market coupling leads to 30-55% more interchange than partial coupling, depending on market conditions.

Table 120: Comparison of 2025 net interchange of the SEE region with rest of the world (all scenarios and MC levels)

Net interchange (GWh)	Baseline	Dry hydrological conditions	High level of RES penetration and low demand	High level of RES penetration, low demand and dry hydrological conditions
Separated markets	9,331.51	3,604.24	18,730.13	12,921.76
Partial market coupling	11,308.69	3,771.15	21,351.90	14,930.40
Change (million €)	1,977.18	166.91	2,621.78	2,008.64
Change (%)	21.19	4.63	14.00	15.54
Full market coupling	12,138.05	5,813.45	22,253.93	16,014.48
Change (million €)	2,806.54	2,209.21	3,523.80	3,092.72
Change (%)	30.08	61.29	18.81	23.93

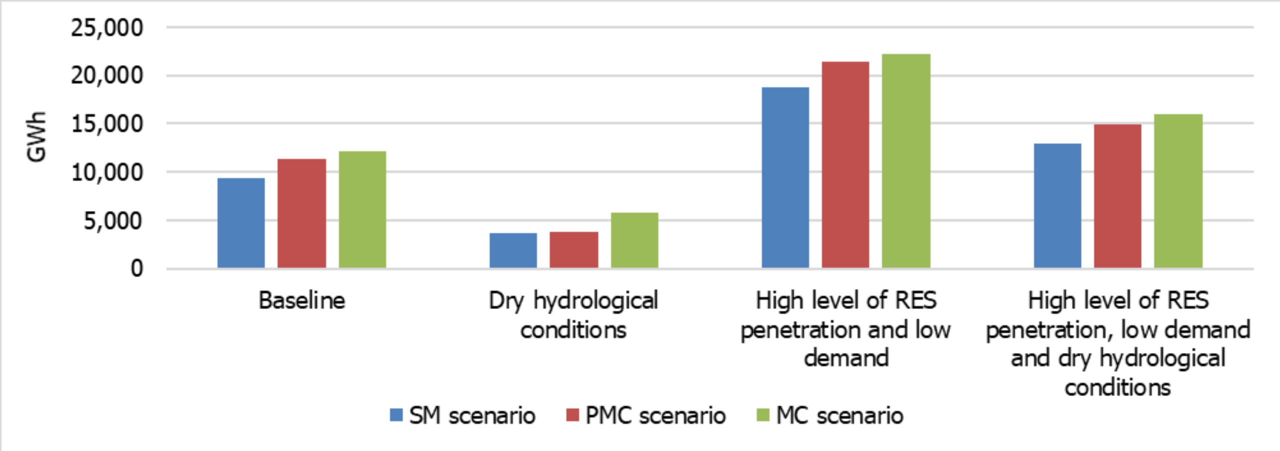


Figure 104: Net interchange (net export) in 2025, of the SEE region with the rest of the world (all scenarios and MC levels)

Our general conclusion is that the increased utilization of cross-border capacities that comes with increased coupling and market integration will enable both higher exports from the SEE region, and higher exports and imports within the EMI market areas.

Wholesale Prices. Looking at the impact on wholesale electricity prices (Table 120 and Figure 104, this analysis shows that:

- Across all scenarios and conditions, we expect average weighted wholesale prices for the SEE region in 2025 to range from 50.04 to 58.70 €/MWh, while in particular market areas and conditions, those prices show a wider range, from 48.01 €/MWh to 69.57 €/MWh.
- Prices would be the highest in dry hydrological conditions, rising 3.0% to 4.6% across the boards compared to the baseline scenario (a notable but modest impact on the whole):
  - Min: 53.92 €/MWh (ESO EAD market area)
  - Max: 69.57 €/MWh (ADMIE/IPTO market area)
  - Average for SEE region: 58.70 €/MWh to 57.40 €/MWh for different MC variants

  This result is expected, given that HPPs provide about 25% of overall generation in the region, and dry hydrological conditions would require the use of higher cost resources, while also presenting the most stressed operating conditions.
- By contrast, average wholesale prices in 2025 would be the lowest if demand growth is slower, and RES development is faster. For the SEE region as a whole, wholesale power prices are 9.2% to 10.8% lower than under the baseline conditions (a major reduction):
  - Min: 48.01 €/MWh (TransElectrica market area)
  - Max: 54.97 €/MWh (HOPS market area)
  - Average for SEE region: 50.04 €/MWh to 50.59 €/MWh for different MC variants

  This is also expected, for several reasons: 1) as in all other cases, these are wholesale prices determined as marginal operating costs (without the investment component); 2) lower demand allows the use of cheaper generating units; and 3) with higher RES participation, a larger share of demand is supplied by RES at essentially zero operating costs.

- In the expected demand case, (both Baseline and Dry hydrology scenarios), prices decrease with stronger market coupling. The reason for this somewhat unexpected result lies in the fact that average prices at the regional level have been calculated as load-weighted average values. Since there is a significant price decrease (between 4 and 7.5 €/MWh) in a large market area (ADMIE/IPTO) and, at the same time, a small price increase (just from 1 to 3 €/MWh) in another large market area (TransElectrica), the average calculated values show a decrease as coupling of markets gets stronger.
- When we combine high RES and slower demand development, wholesale market prices are generally lower in the SEE region compared to neighboring market areas. Thus, stronger market coupling would lead to an increase of exports to neighboring markets and a slight increase in prices. This is expected, keeping in mind that changes in prices (increase or decrease) are similar among market areas and below 2 €/MWh.
- As mentioned above, in the most stressed operating condition (Dry hydrology), prices are the highest, and the price variation coefficient is the highest as well. As expected, stronger market coupling provides for price convergence but, even in full market coupling, wholesale prices stay the most divergent in the dry hydrology scenario (Table 122).

Table 121: Comparison of wholesale electricity prices in 2025 (all scenarios and MC levels)

Price (€/MWh)	Baseline	Dry hydrological conditions	High level of RES penetration and low demand	High level of RES penetration, low demand and dry hydrological conditions
Separated markets	56.12	58.70	50.04	52.03
Partial market coupling	55.83	58.04	50.41	52.42
Change (€/MWh)	-0.28	-0.66	0.37	0.39
Change (%)	-0.51	-1.12	0.73	0.76
Full market coupling	55.74	57.40	50.59	52.40
Change (€/MWh)	-0.37	-1.30	0.55	0.37
Change (%)	-0.67	-2.21	1.10	0.72

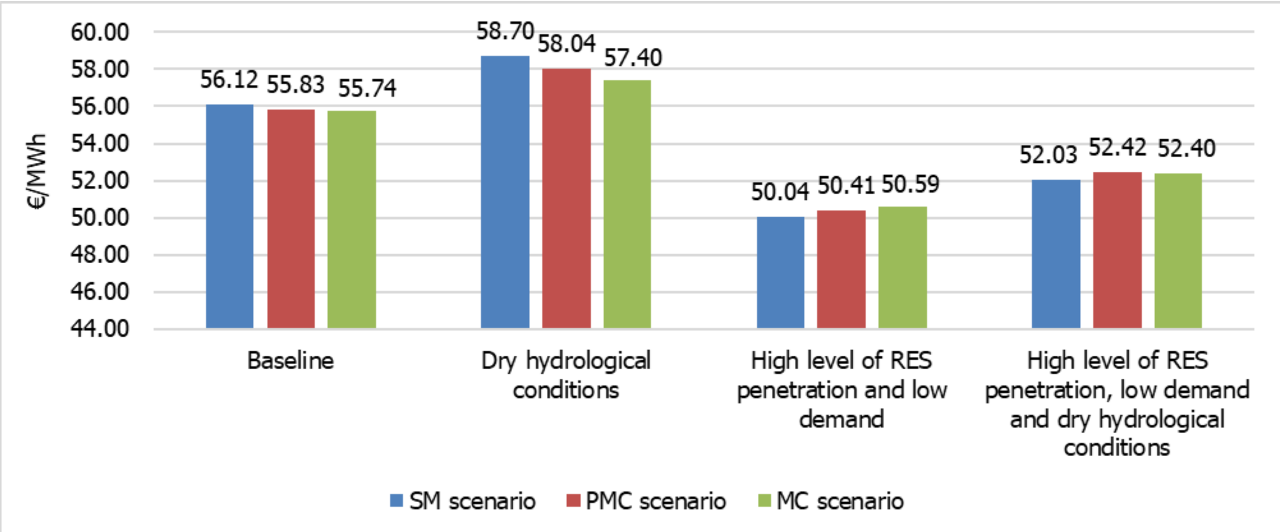


Figure 105: Wholesale electricity prices in 2025 (all scenarios and MC levels)

Table 122: Prices variation coefficient in 2025 (all scenarios and MC levels)

Prices variation (%)	Baseline	Dry hydrological conditions	High level of RES penetration and low demand	High level of RES penetration, low demand and dry hydrological conditions
Separated markets	5.59%	7.07%	4.76%	3.75%
Partial market coupling	3.17%	4.17%	3.11%	2.55%
Full market coupling	2.56%	3.32%	2.54%	2.05%

It is noteworthy that higher exports from the SEE region (to Turkey, Italy and Central Europe) will increase wholesale prices in the near term at the regional level, since internal market coupling will unlock more expensive generation that is not utilized in the SM and PMC cases.

Over a longer time frame, we would expect consolidation of the SEE region with electricity markets in other parts of Europe (e.g., Central and Western Europe), where wholesale power prices are considerably lower. At that point, prices in SEE should converge with those areas, and could well decrease in a meaningful way. The "Caveats" section of the Executive Summary provides more detail on why we believe that there would be downward pressure on prices in all SEE countries, and greater SEW benefits in reality than shown in the results of this sophisticated modeling exercise.

As mentioned above, with the Antares model and the training provided by the EMI, each country can evaluate their own conditions and scenarios in more detail that would lead to these changes, and the policy implications, as greater market integration tends to equalize prices across borders.

Socio-Economic Welfare (SEW). For the whole SEE region, every scenario and market coupling variant would produce at least 20 million € in benefits compared to separated markets, and those benefits increase substantially – generally about 50% - from partial to full market coupling. This is a notable point in favor of consolidating power markets.

Including congestion rents, the biggest benefit of market coupling compared to separated markets would occur in the most stressed operating conditions (Dry hydrology) and it can reach 41 million €. We expect a similar level of benefits in the Baseline scenario, and the scenario with lower demand and increased RES - 37 million €. The lowest SEW benefits (30 million €) can be expected with dry hydro, slow demand growth, and increased RES. Without congestion rents, the benefits rise farther (e.g., 51-81 million € in the scenario with dry hydro, low demand and high RES).

Table 123: SEW variation compared to separated markets, across scenarios and MC levels in 2025

Δ SEW (million €)	Baseline	Dry hydrological conditions	High level of RES penetration and low demand	High level of RES penetration, low demand and dry hydrological conditions
Partial market coupling	26.23	27.28	23.64	20.62
Full market coupling	37.02	40.86	37.28	30.02

In general, the largest benefits across scenarios and levels of integration in SEE would occur in the ADMIE/IPTO and ELES market areas. For the ADMIE/IPTO market area, the main reason is the presence of adequacy issues (or energy not served (ENS)), which leads to a meaningful price decrease and thus an increase in SEW with stronger market coupling. For ELES, the key reasons are increased, significant transit of power flows across the country, and price differences with neighboring market areas.

In fact, for most countries, under most conditions, the SEW is positive, some quite substantially so. These benefits can also be related to the size of the power markets and economies (e.g., a million euros is a larger share of the size of the economy and electricity market in some countries versus others). Also, in this project we have modeled the impact of these scenarios and conditions without policy changes. These benefits would grow if regulators and countries enact programs designed to increase their SEW and that of the SEE region.

While the region as a whole clearly benefits, the SEW in individual market areas could fall a bit with stronger market coupling (see Table 3 - Table 6). The decreases occur mainly due to either: a) large decreases in congestion rents on some borders (e.g., BG-GR); or b) to price increases in smaller importing market areas (e.g., MEPSO or CGES) due to a stronger connection with exporting and importing areas, and an increase in power transits. Also, in small but exporting market areas, such as KOSTT, the decrease in transits, congestion and wholesale prices in some scenarios leads to a decrease in SEW. The same is true for the HOPS market area, which is an importing area between areas with significant price differences (NOSBiH and HU).

These individual, near-term impacts do not detract from our overall conclusion that market consolidation and coupling is better for customers and for the SEE region. Moreover, as mentioned above, we expect that the markets that show SEW reductions in 2025 are temporary and transitional impacts, and that greater consolidation of this region with Central Europe over time will more than reverse these reductions (see the "Caveats" section of the Executive Summary for more detail).

6 CONCLUSIONS AND NEXT STEPS

This chapter presents the main findings resulting from the EMI analyses of electricity market integration in the SEE region, as detailed in the prior sections of this report.

In general, our market analysis in 2025 shows clearly how market coupling and better utilization of cross-border capacities for commercial electricity exchange will support many positive impacts: higher exports from the SEE region; more interchange within the region; the convergence of wholesale electricity prices; and a meaningful increase in socio-economic welfare (SEW) for the SEE region. This increase in SEW is an important indicator of the impact of market coupling on the individual market areas, and to the SEE region as a whole.

This is particularly true when one takes congestion rents out of the equation, and we focus on the consumer and producer surpluses. **From this perspective, every market area benefits in every scenario and market condition when power markets consolidate in the SEE region.**

Our work shows that across all scenarios and market coupling (MC) variations, the average weighted prices for the whole SEE region in 2025 will range from 50.04 to 58.70 €/MWh, while particular market areas prices show a wider separation, from 48.01 €/MWh (TransElectrica market area) to 69.57 €/MWh (ADMIE/IPTO market area). These prices would be the highest in dry hydrological conditions, and will be the lowest if we combine low demand growth with rapid RES development. Moreover, these two conditions – lower demand growth and higher RES development – are ones on which utilities, regulators and policy makers can have an influence, and can help to create.

After analyzing different market parameters, we calculate the change in SEW to evaluate the overall benefits of regional market integration in the SEE region. SEW for the whole SEE region would be highest under full market coupling in the most stressed operating conditions (i.e., dry hydrology), when it could reach 41 million €. Given our changing climate, we expect more cases of wet and dry years in the future, so it is helpful to know that SEW benefits are high under such conditions.

We expect similar benefits in the baseline scenario, under conditions of slower demand and higher RES development, when the SEW would be 37 million €. We would expect the lowest SEW benefits (30 million €) in dry hydrological conditions combined with slow demand and high RES development.

Even though electricity prices increase in some market areas and scenarios under market coupling, this should not deter the EMI participants from encouraging market integration. The increase in some electricity prices, which occurs just in the high RES and low demand circumstances, is due to the increase in SEE regional electricity generation to provide for more exports to external markets, where prices are generally higher.

Moreover, we point out that this analysis focused on 2025. If we look farther into the future, we note that prices in Central Europe are a good deal lower on average than in SEE, so we would expect a meaningful convergence with prices in that region as SEE markets integrate into and couple with the rest of Europe. That is, higher prices in 2025 in a few markets under some conditions would appear to be a transition step to meaningfully lower wholesale prices in the future.

For this work, most prices are lower under market consolidation, but we believe that SEW is an even better measure of the benefits which market coupling could bring by 2025. For some electricity market areas, such as the ELES, HOPS, OST and MEPSO market areas, the SEW does not increase in each scenario and for each level of market coupling. That could be perceived as a negative signal to proceed with market coupling process and integration with neighboring market areas.

However, as mentioned in the prior Chapter of this report, and in the "Caveats" section of the Executive Summary, we expect that these SEW reductions to be temporary and transitional, in part because this work is a snapshot of impacts in 2025, and that greater consolidation of this region with Central Europe over time will more than reverse these reductions. Thus, these modest SEW reductions in some cases should not be a deterrent to regional electricity market consolidation.

Also, it is important to take a regional, holistic, societal perspective. The results we provide in this study clearly indicate that partial market coupling and full regional integration leads to a more efficient and transparent electricity market, as well as to more rational usage of the SEE power systems for the benefit of all EMI working group members and customers in the region.

In particular, we believe that with greater market integration, wholesale power costs in all SEE markets could well decrease, SEWs will be higher, and that those benefits will grow larger over time.

In this work, we conducted extensive market simulations that show how, with minimum technical interventions in the power system, it is possible to gain significant benefits from both a technological and economic point of view. Market coupling, whether partial or full, leads to economic and efficiency benefits in the convergence of wholesale electricity prices on the SEE region level, which is also in line with EU goals on energy policy and internal energy markets.

We also note that the much greater diversity of generation and transmission resources available to the region through electricity market coupling and integration (as opposed to individual market areas) would support the more secure and reliable operation of the SEE power system. Addressing reliability and congestion matters is of the utmost importance to contemporary power systems, particularly with the planned addition of significant RES generation in the coming years. The next EMI study – for which we are in the process of finalizing the Terms of Reference - will simultaneously address both market and reliability questions in detail, for the year 2030, in the SEE region.

We strongly encourage TSOs, MOs and other EMI stakeholders in SEE to use the results and conclusions in this market analysis to carry out their own assessments, and as appropriate, to proceed with a higher level of electricity market integration for their countries and the SEE region. To achieve these benefits and to fully exploit their potential will require synergy and collaboration among all key stakeholders (TSOs, MOs, regulatory bodies, policy makers, etc.).

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APPENDIX I: MARKET MODELING DATABASE

This appendix provides a review of the expected power system status in the year 2025 for each EMI WG member, along with an overview of the data, assumptions and proxies used to develop the corresponding model in the Antares software tool, and the analysis contained in this report.

The OST market area

The OST market area – Demand

Forecasted baseline consumption in the OST market area is 8.5 TWh in 2025 (Table I), and the observed peak load is 1,797 MW (Figure I). The highest consumption is observed in the winter months (December, January), while the lowest consumption is in the mid-spring and autumn months (May, September), as depicted in Figure II. The dataset related to the hourly load profile was taken from the TYNDP 2018 scenario Best Estimate 2025.

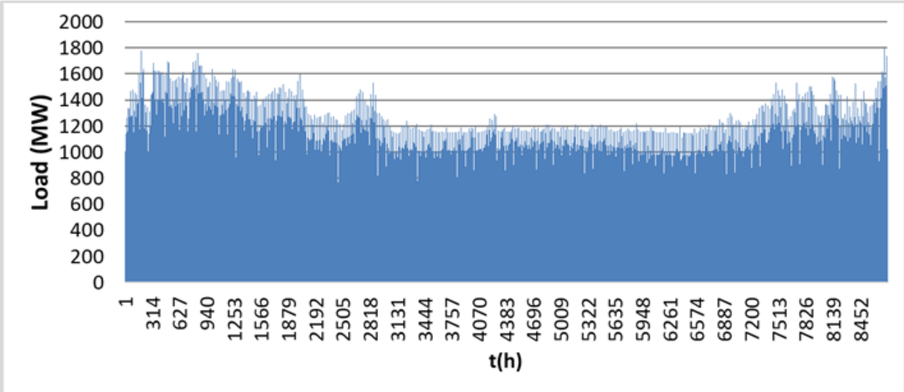

Figure I: Hourly load profile in 2025 – the OST market area

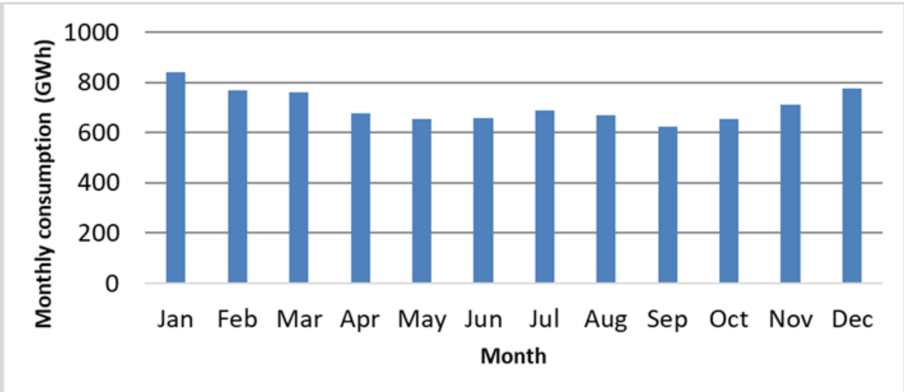

Figure II: Monthly energy consumption (GWh) for 2025 – the OST market area

In the low demand scenario, with a reduced growth rate, the total annual consumption would be 7.8 TWh, as shown in Table I.

Table I: Baseline and low demand scenarios in 2025 – the OST market area

EMI Member	Demand in 2017 (TWh)	Baseline scenario		Low demand scenario	
		Growth rate from 2017 to 2025	Demand in 2025 (TWh)	Growth rate from 2017 to 2025	Demand in 2025 (TWh)
AL	7.1	2.20%	8.45	1.10%	7.75

The OST market area – Production

For OST, no thermal units are envisaged in 2025. Wind and solar power plants will participate with 80 MW and 50 MW, respectively (Table II).

Table II: Installed capacities per technology in 2025 – the OST market area

Technology	Installed capacity (MW)
Hydro	2460
Wind	80/150[5]
Solar	50/80[5]

In 2025, the OST market area will still be highly dependent on hydro production, with 95% of the installed capacity in HPPs, with 5% of generation capacity from wind and solar (Figure III).

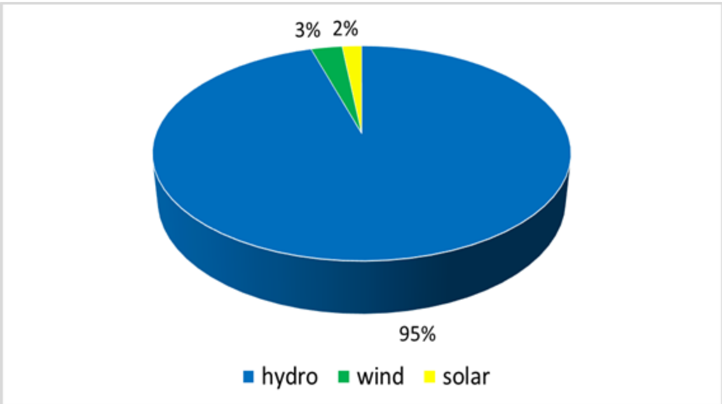

Figure III: Installed capacity per fuel type in 2025 – the OST market area

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

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

The 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%

Due to missing HPP data in different hydrological conditions, we calculated their generation based on received data from HPPs in the OST market area. Table IV table shows the annual forecasted generation of all HPPs in the OST market area for different hydrological conditions. Dry years are approximately half the generation of wet ones, and average years halfway between them.

Table IV: Annual generation for all HPPs for dry, average and wet hydrology – the OST market area

Annual generation (GWh)	Dry	Average	Wet
ROR	1680	2509	3223
HPPs with reservoirs	3996	5923	8087
Total	5676	8432	11310

The OST market area – Network transfer capacities

The network transfer capacities between the OST market area and neighboring market areas are not expected to change by 2025 (with the fully commissioned XK-AL link), as shown in Table V.

Table V: Network transfer capacities in 2025 – the OST market area

NTC (MW) in 2025	Win/Aut	Sum/Spr
XK – AL	**650**	**610**
AL – XK	**650**	**610**
AL – ME	**500**	**500**
ME – AL	**500**	**500**
AL – GR	**250**	**250**
GR – AL	**250**	**250**
AL – MK	**400**	**400**
MK – AL	**600**	**600**

The NOSBiH market area

The NOSBiH market area – Demand

Demand in the NOSBiH market area is relatively low at present, and is expected to grow somewhat, but the NOSBiH market area will probably remain a net exporter of power. The peak load in the NOSBiH market area in 2025 will be around 2,250 MW, with the minimum load expected to be about 800 MW, as shown in Figure IV. The highest consumption is observed during the winter, while in spring and September, electricity consumption is at the lowest levels (Figure V).

NOSBiH provided the dataset related to the NOSBiH market area's hourly load profile in 2025.

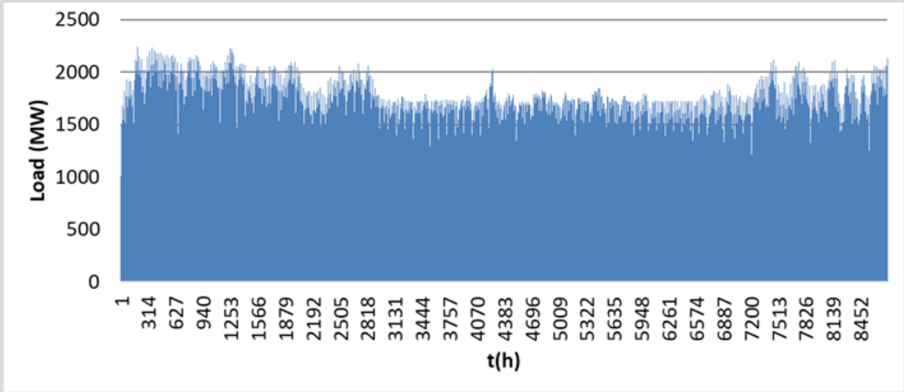

Figure IV: Hourly load profile in 2025 – the NOSBiH market area

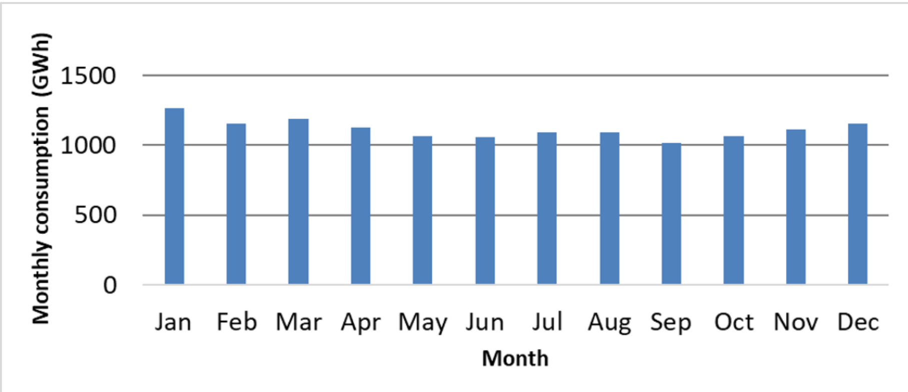

Figure V: Monthly energy consumption (GWh) for 2025 – the NOSBiH market area

Total consumption in the baseline scenario is expected at 13.5 TWh, while with low demand growth, the total annual consumption would be approximately 13 TWh (Table VI).

Table VI: Baseline and low demand scenarios in 2025 – the NOSBiH market area

EMI Member	Demand in 2017 (TWh)	Baseline scenario		Low demand scenario	
		Growth rate from 2017 to 2025	Demand in 2025 (TWh)	Growth rate from 2017 to 2025	Demand in 2025 (TWh)
BA	12.6	0.87%	13.5	0.43%	13.04

The NOSBiH market area – Production

For the NOSBiH market area, all the necessary data related to thermal as well as to hydro power plants were provided by the relevant TSO (NOSBiH).

With regards to the TPPs in the NOSBiH market area, they are dominated by locally sourced coal-fired power plants. For this reason, it is not expected that any new gas-fired TPPs will be built.

The NOSBiH market area has significant wind resources, and we assumed that in 2025, 350 MW of wind power plants will be online. Concerning solar power plants, we expect 50 MW of solar based power plants by 2025, as given in Table VII.

Table VII: Installed capacities per technology in 2025 – the NOSBiH market area

Technology	Installed capacity (MW)
Thermal - lignite	1765
Hydro	2308
Wind	350/640[5]
Solar	50/100[5]

As can be seen in Figure VI, the NOSBiH market area has significant hydro resources, as well. The capacity of HPPs is more than half of total generation capacity.

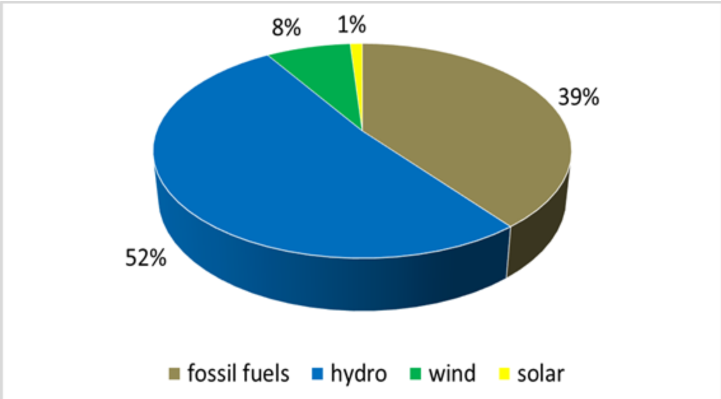

Figure VI: Installed capacity per fuel type in 2025 – the NOSBiH market area

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

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

The 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%

The hydro generation for average, dry and wet hydrology was provided by the relevant TSO (NOSBiH). The total annual generation for Run of River (ROR) and storage HPP (with reservoir) are given in Table IX.

Table IX: Annual generation for all HPPs for dry, average and wet hydrology – the NOSBiH market area

Annual generation (GWh)	Dry	Average	Wet
ROR	2220	3038	3848
HPPs with reservoirs	2231	2694	3294
Total	4451	5732	7142

Table X provides data regarding modeling of the single PSHPP in the NOSBiH market area.

Table X: PSHPP data – the NOSBiH market area

Name	Number of units	Pgen (MW)	Ppump (MW)	Efficiency
PSHPP Čapljina	2	220	220	75%

The NOSBiH market area – Network transfers capacities

By 2025, the situation in the NOSBiH market area interconnections with neighboring countries will be improved due to the nominal transmission capacity increase on interconnection between the NOSBiH market area and the EMS market area. Network transfer capacities are shown in Table XI.

Table XI: Network transfer capacities in 2025 – the NOSBiH market area

NTC (MW) in 2025	Win/Aut	Sum/Spr
RS - BA	**600**	**600**
BA - RS	**600**	**600**
BA - ME	**600**	**600**
ME - BA	**600**	**600**
HR - BA	**1000**	**1000**
BA - HR	**1200**	**1050**

The ESO EAD market area

The ESO EAD market area – Demand

The forecasted consumption in the ESO EAD market area is 34.9 TWh in 2025 (Table XII). The observed peak load is 6583 MW, with a load factor of 61.5% (Figure VII). The highest monthly consumption is observed during the 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 VIII).

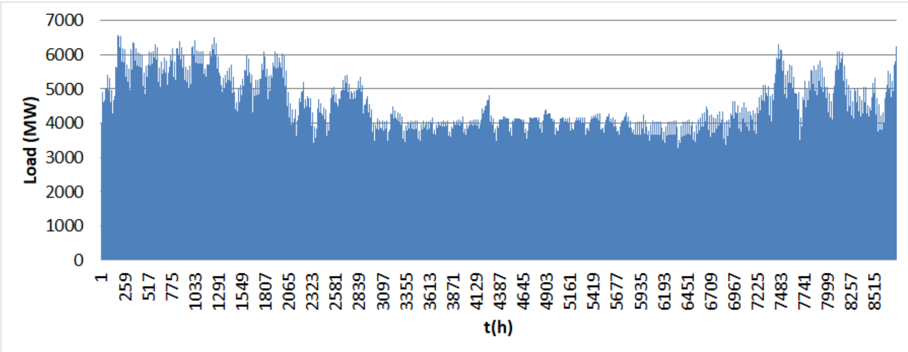

Figure VII: Hourly load profile in 2025 – ESO EAD market area

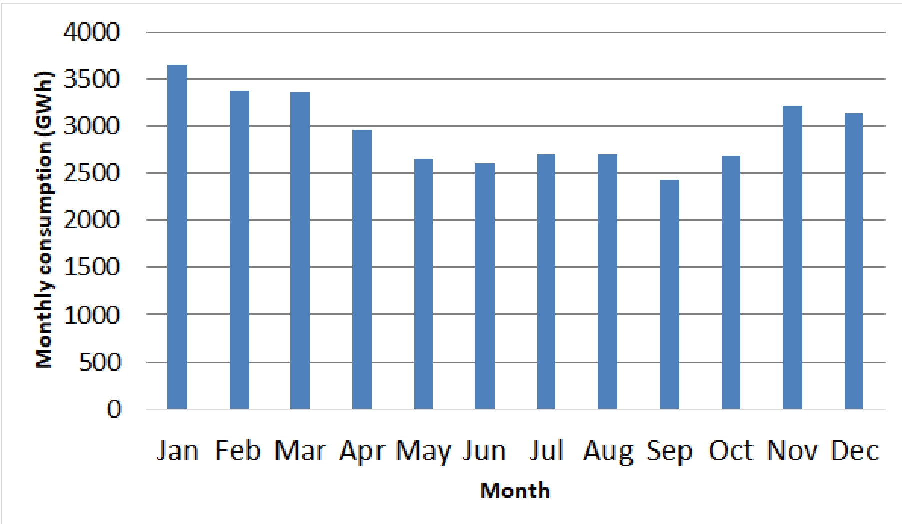

Figure VIII: Monthly energy consumption (GWh) for 2025 – ESO EAD market area

Total consumption in the baseline scenario is expected to be 34.9 TWh, while in the low demand scenario, with a reduced growth rate, annual consumption would be 34.6 TWh (Table XII).

Table XII: Baseline and low demand scenarios in 2025 – ESO EAD market area

EMI Member	Demand in 2020 (TWh)	Baseline scenario		Low demand scenario	
		Growth rate from 2020 to 2025	Demand in 2025 (TWh)	Growth rate from 2020 to 2025	Demand in 2025 (TWh)
BG	34.3	0.34%	34.9	0.17%	34.6

The ESO EAD market area – Production

In 2025, the ESO EAD market area will have a highly diversified production mix. Around 63% of installed capacity is in thermal plants, most of them base load plants (nuclear, lignite, hard coal). Installed capacity in renewable generation will rise to 2,500 MW in wind and solar in 2025[10], while hydro generation will account almost one fifth of installed capacity (Table XIII and Figure IX).

Table XIII: Installed capacities per technology in 2025 – the ESO EAD market area

Technology	Installed capacity (MW)
Thermal - lignite	3894
Thermal - hard coal	365
Thermal - gas	2034
Thermal - nuclear	2080
Hydro	2609
Wind	1000/1250[5]
Solar	1500/2000[5]

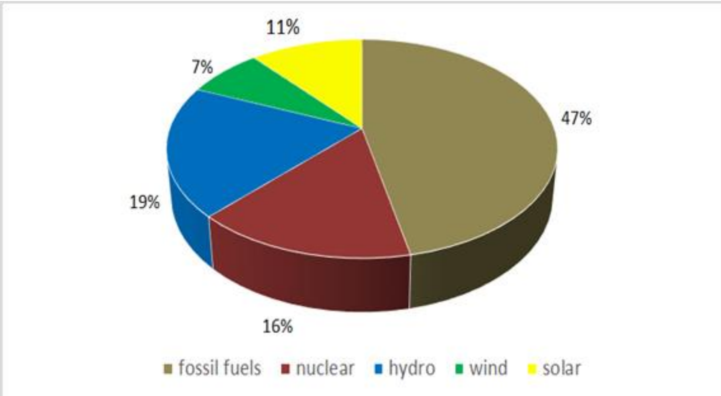

Figure IX: Installed capacity per fuel type in 2025 – ESO EAD market area

Table XIV 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 ESO.

Table XIV: Average wind and solar capacity factors for 1982,1984 and 2007 – the 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%

[10] As presented in TYNDP 2018

Annual generations of all HPPs for different hydrological conditions are given in Table XV. ESO did not provide generation for dry and wet hydrological conditions, so we calculated them by multiplying the average generation with coefficients 0.75 and 1.25, respectively.

Table XV: Annual generation for all HPPs for dry, average and wet hydrology – the ESO EAD market area

Annual generation (GWh)	Dry	Average	Wet
ROR	786	1048	1310
HPPs with reservoirs	2359	3145	3931
Total	3145	4193	5241

Table 20 shows the essential data needed for modeling PSHPP in the ESO EAD market area in 2025. In this case, we have estimated the efficiency of PSHPP, while other data were provided by ESO.

Table XVI: PSHPP data – the ESO EAD market area

Name	Number of units	Pgen (MW)	Ppump (MW)	Efficiency
PSHPP Chaira	4	210	185	75%
PSHPP Belmeken	2	75	52	75%
PSHPP Orfei	1	40	40	75%

The ESO EAD market area – Network capacity

In terms of the network capacity in the ESO EAD market area, we expect in 2025 a substantial increase of cross-border capacities compared to the current state, especially on the borders with the TransElectrica market area, the ADMIE/IPTO market area and Turkey, without changes on the borders with the MEPSO market area and the EMS market area. Also, there is no differences between NTCs in winter and summer, as shown in Table XVII.

Table XVII: Network transfer capacities in 2025 – the ESO EAD market area

NTC (MW) in 2025	Win/Aut	Sum/Spr
BG - RS	400	400
RS - BG	400	400
BG - MK	500	500
MK - BG	400	400
RO - BG	1100	1100
BG - RO	1200	1200
BG - GR	1350	1350
GR - BG	800	800
BG - TR	900	900
TR - BG	500	500

The HOPS market area

The HOPS market area – Demand

In the HOPS market area, it is expected that the peak load will be around 3,400 MW, with the minimum load of around 1,500 MW (Figure X). 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 XI.

The dataset related to the HOPS market area hourly load profile in 2025 was taken from the TYNDP 2018 scenario Best Estimate 2025.

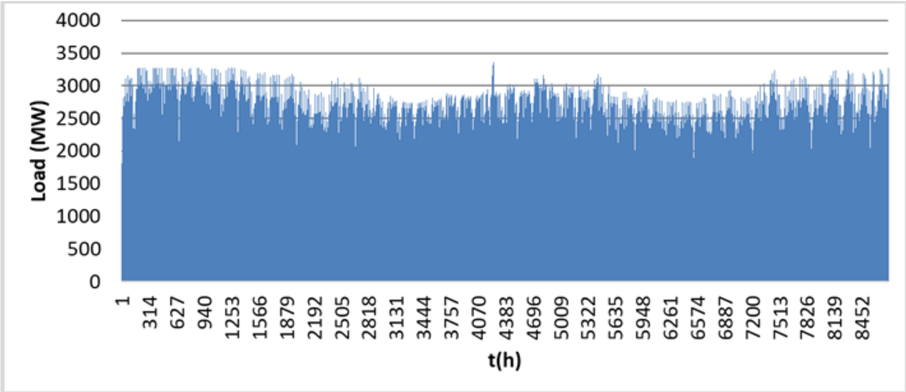

Figure X: Hourly load profile in 2025 – the HOPS market area

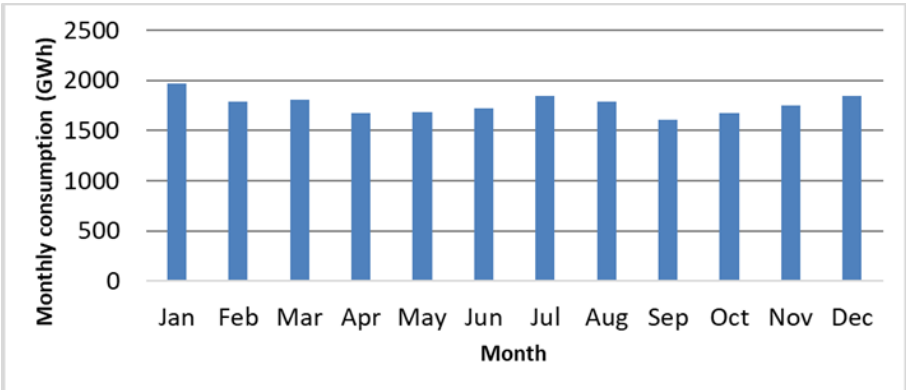

Figure XI: Monthly energy consumption (GWh) for 2025 – the HOPS market area

Total consumption in the baseline scenario in 2025 is expected to be 21 TWh, while in the low demand scenario, with a reduced growth rate, total annual consumption would be around 19.5 TWh, as given in Table XVIII.

Table XVIII: Baseline and low demand scenarios in 2025 – the HOPS market area

EMI Member	Demand in 2017 (TWh)	Baseline scenario		Low demand scenario	
		Growth rate from 2017 to 2025	Demand in 2025 (TWh)	Growth rate from 2017 to 2025	Demand in 2025 (TWh)
HR	17.9	2.08%	21.10	1.04%	19.44

The 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 HPP (dry and wet hydrology). We took the missing data related to TPPs from the TYNDP 2018 ENTSO-E database.

As can be seen from Table XIX, the HOPS market area in 2025 will be dominated by hydro power plants. The TPPs in the HOPS market area are expected to have about a quarter 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 XIX: Installed capacities per technology in 2025 – the HOPS market area

Technology	Installed capacity (MW)
Thermal – gas	692
Thermal - hard coal	297
Hydro	2119
Wind	1000/1500[5]
Solar	400/800[5]

Wind power plants will take the same share as TPPs, while solar power plants will participate with 9% in total generation capacities (Figure XII), for a total of 31% of installed capacity from renewable projects in 2025.

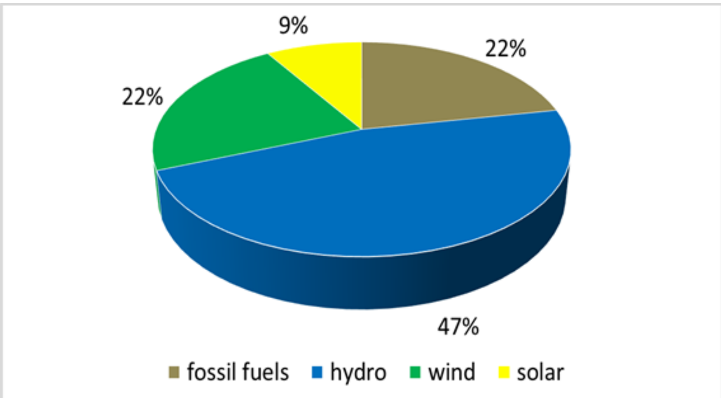

Figure XII: Installed capacity per fuel type in 2025 – the HOPS market area

Due to the fact that hourly capacity factors for wind and solar generation were not available, we used data on capacity factors for the HOPS market area from the publicly available database – Renewables.ninja. However, hourly data from Renewables.ninja seemed unrealistic for the HOPS market area and too low compared to other market areas, so hourly capacity factors from Renewables.ninja were adjusted to reach average yearly capacity factors reported by HOPS, as shown in Table XX.

Table XX: Adopted average wind and solar capacity factors for 1982, 1984 and 2007 – the 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 average hydrology. We assumed the hydro generation in dry and wet hydrological conditions to be ±25% of the generation in average conditions. Annual generation of the portfolio of hydro power plants in the HOPS market area for different hydrological conditions is in Table XXI.

Table XXI: Annual generation for all HPPs for dry, average and wet hydrology – the HOPS market area

Annual generation (GWh)	Dry	Average	Wet
ROR	1345	1794	2242
HPPs with reservoirs	3285	4380	5475
Total	4630	6173	7717

Table 26 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, while the HOPS provided data on the number of units and generation capacity.

Table XXII: PSHPP data – the 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	276.0	240.0	75%
PSHPP Blato	3	10.5	10.2	75%

The HOPS market area – Network capacity

With regards to network capacity, the interconnection levels between the HOPS market area and its neighboring countries in 2025 will stay the same as at present. The NTC values related to the HOPS market area are shown in Table XXIII.

Table XXIII: Network transfer capacities in 2025 – HOPS market area

NTC (MW) in 2025	Win/Aut	Sum/Spr
RS - HR	500	500
HR - RS	500	500
HR - BA	1000	1000
BA - HR	1200	1050
HR - HU	1000	1000
HU - HR	1200	1200
HR - SI	1500	1000
SI - HR	1500	1100

The ADMIE/IPTO market area

The ADMIE/IPTO market area – Demand

The forecasted peak load in 2025 is 12,403 MW, with a load factor of 56.44% (Figure XIII). 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 XIV).

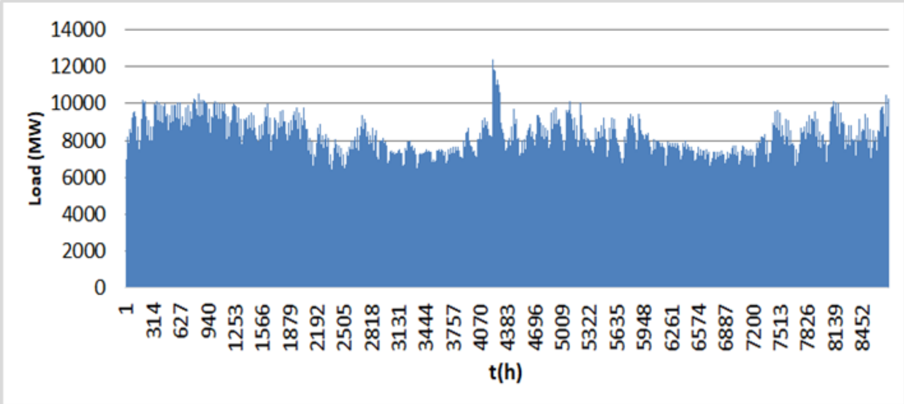

Figure XIII: Hourly load profile in 2025 – the ADMIE/IPTO market area

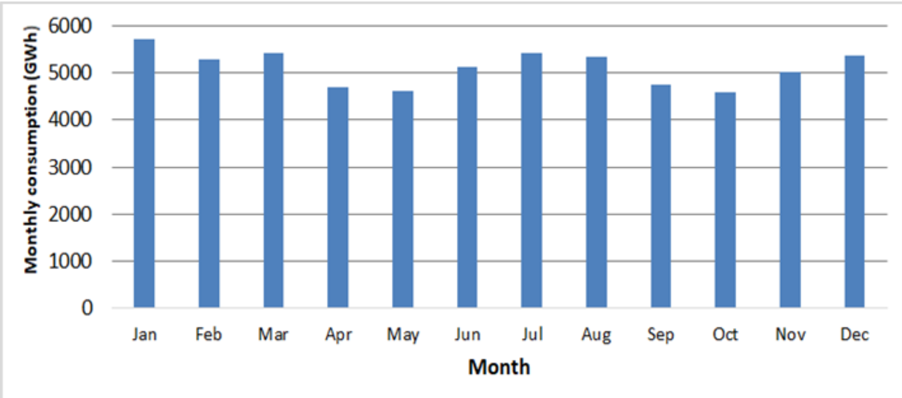

Figure XIV: Monthly energy consumption (GWh) for 2025 – the ADMIE/IPTO market area

Total consumption in the baseline scenario in 2025 is expected to be 61.3 TWh, while in the low demand scenario, with a reduced growth rate, total annual consumption would be 56.35 TWh (Table XXIV).

Table XXIV: Baseline and low demand scenarios in 2025 – the ADMIE/IPTO market area

EMI Member	Demand in 2017 (TWh)	Baseline scenario		Low demand scenario	
		Growth rate from 2017 to 2025	Demand in 2025 (TWh)	Growth rate from 2017 to 2025	Demand in 2025 (TWh)
GR	51.9	2.07%	61.3	1.03%	56.35

The ADMIE/IPTO market area – Production

In 2025, the ADMIE/IPTO market area will have highly diversified production mix. With 4,160 MW of installed generation in wind and 3,400 MW in solar, giving the ADMIE/IPTO market area the largest renewable generation fleet in the region, with a share of 37% in total installed capacity. Thermal power plants will comprise 47% of total installed capacity, with most of them gas-fired plants. The share of HPP is around 16% (Table XXV and Figure XV).

Table XXV: Installed capacities per technology in 2025 – the ADMIE/IPTO market area

Technology	Installed capacity (MW)
Thermal - lignite	3397
Thermal – gas	5862
Thermal - heavy oil	98
Thermal - light oil	310
Hydro	3210
Wind	4160/6200[5]
Solar	3400/4000[5]

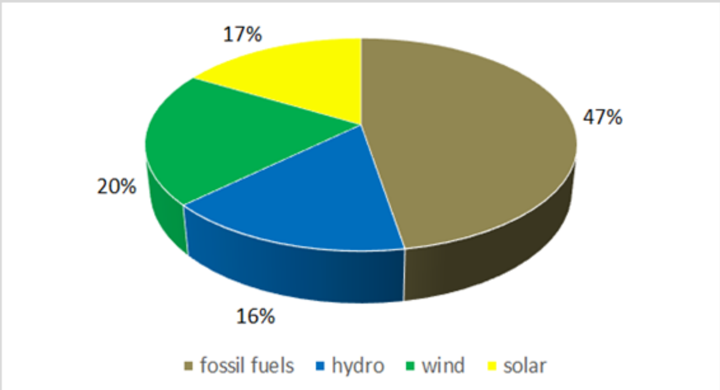

Figure XV: Installed capacity per fuel type in 2025 – the ADMIE/IPTO market area

Table 30 shows the annual average wind and solar capacity factors the ADMIE/IPTO market area has one of the highest solar capacity factors in the region, almost 18%.

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

ADMIE/IPTO market area – average wind and solar capacity factors			
Year	**1982**	**1984**	**2007**
Wind CF	21.10%	18.06%	20.28%
Solar CF	17.65%	17.64%	17.96%

For hydro, IPTO provided expected generation on a technology level: for RoR and HPPs with reservoirs. They provided generation for HPPs with reservoirs for all three hydrological conditions, and we will use the same ratio for RoR HPPs (Table XXVII).

Table XXVII: Annual generation for all HPPs for dry, average and wet hydrology

Annual generation (GWh)	Dry	Average	Wet
ROR	511	930	1278
HPPs with reservoirs	2200	4000	5500
Total	2711	4930	6778

In Table XXVIII shows data regarding the ADMIE/IPTO market area's PSHPP. While IPTO provided the number of units, the Pgen, Ppump and efficiency are our assessment.

Table XXVIII:PSHPP data – the 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%

The ADMIE/IPTO market area – Network capacity

For the ADMIE/IPTO market area, there are no significant interconnection projects that will affect the NTCs with neighboring countries by 2025, but IPTO plans to connect Crete with the mainland with an 800 MW cable. Also we have note that the borders with the MEPSO market area and the ESO EAD market area have the highest transmission capacities, while the border with OST market area has the smallest (Table XXIX).

Table XXIX: Network transfer capacities in 2025 – the ADMIE/IPTO market area

NTC (MW) in 2025	Win/Aut	Sum/Spr
AL - GR	**250**	**250**
GR - AL	**250**	**250**
MK - GR	**650**	**1000**
GR - MK	**650**	**1000**
BG - GR	**1350**	**1350**
GR - BG	**800**	**800**
GR - TR	**433**	**366**
TR - GR	**466**	**400**

The KOSTT market area

The KOSTT market area – Demand

In the KOSTT market area, the projected peak load in 2025 is 1,200 MW, with a load factor of 60.8% (Figure XVI). The highest monthly consumption is expected in the winter months (December, January), while the lowest consumption and flat monthly profile are present from May to September (Figure XVII).

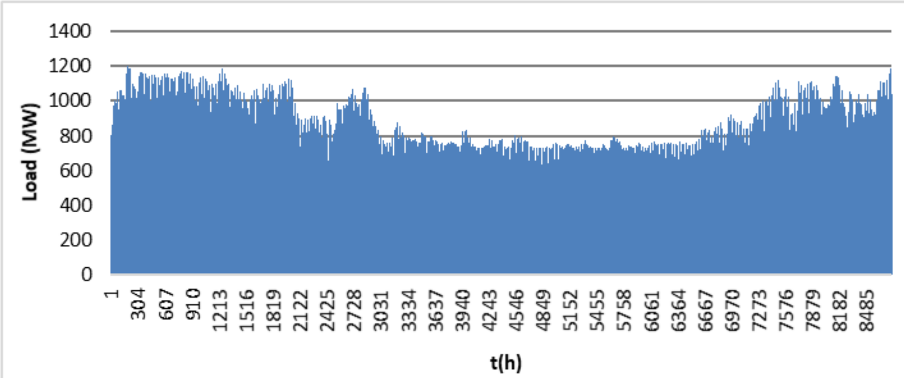

Figure XVI: Hourly load profile in 2025 – the KOSTT market area

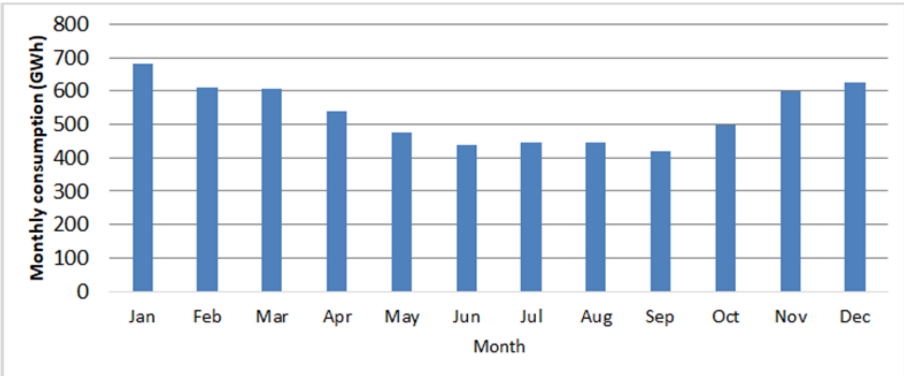

Figure XVII: Monthly energy consumption (GWh) for 2025 – the KOSTT market area

Total consumption in the baseline scenario is expected to be 6.38 TWh, while in the low demand scenario, with half this growth rate, total annual consumption would be 5.48 TWh (Table XXX).

Table XXX: Baseline and low demand scenarios in 2025 – the KOSTT market area

EMI Member	Demand in 2017 (TWh)	Baseline scenario		Low demand scenario	
		Growth rate from 2017 to 2025	Demand in 2025 (TWh)	Growth rate from 2017 to 2025	Demand in 2025 (TWh)
XK	4.7	3.89%	6.38	1.95%	5.48

The KOSTT market area – Production

In 2025, the KOSTT market area will still be highly dependent on lignite plants, with an 81% share of installed capacity. The share of RES (wind and solar) will be around 15%, and the share of HPPs will be just 4% (Table XXXI and Figure XVIII).

Table XXXI: Installed capacities per technology in 2025 – the KOSTT market area

Technology	Installed capacity (MW)
Thermal - lignite	1410
Hydro	66
Wind	150/200[5]
Solar	60/100[5]

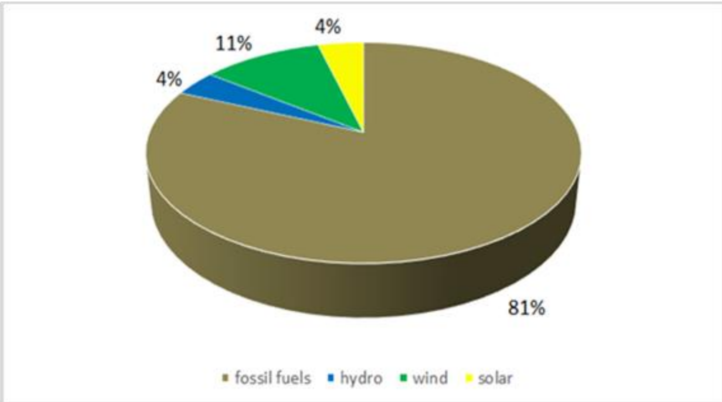

Figure XVIII: Installed capacity per fuel type in 2025 – the KOSTT market area

Table XXXII a shows the average annual capacity factors for wind and solar power plants, calculated on the basis of the time series provided by KOSTT. The KOSTT market area has one of highest average wind capacity factors in the region.

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

KOSTT market area– average wind and solar capacity factors			
Year	**1982**	**1984**	**2007**
Wind CF	20.92%	20.46%	22.61%
Solar CF	15.66%	15.23%	15.88%

Table 37 shows the annual generations of all the market area's HPPs for different hydrological conditions KOSTT did not provide generation for dry and wet hydrological conditions, so we have calculated them, as for several other countries/market areas, by multiplying average generation with coefficients of 0.75 and 1.25, respectively.

Table XXXIII: Annual generation for all HPPs for dry, average and wet hydrology – the KOSTT market area

Annual generation (GWh)	Dry	Average	Wet
ROR	65	87	109
HPPs with reservoirs	63	84	105
Total	128	171	214

The KOSTT market area – Network capacity

Major changes in NTCs are not foreseen by 2025. The NTCs vary from 300 MW to 700 MW, with the same figures in both winter and summer, except on the border with the MEPSO market area (Table XXXIV).

Table XXXIV: Network transfer capacities in 2025 – the KOSTT market area

NTC (MW) in 2025	Win/Aut	Sum/Spr
XK - MK	**325**	**325**
MK - XK	**200**	**200**
XK - AL	**650**	**610**
AL - XK	**650**	**610**
RS - XK	**300**	**300**
XK - RS	**400**	**400**
XK - ME	**300**	**300**
ME - XK	**300**	**300**

The MEPSO market area

The MEPSO market area – Demand

The forecast peak load for 2025 is 1655 MW, with a load factor of 61.8% (Figure XIX). Figure 27 shows that the highest monthly consumption is expected in January, while the lowest consumption is anticipated at the beginning and end of the summer.

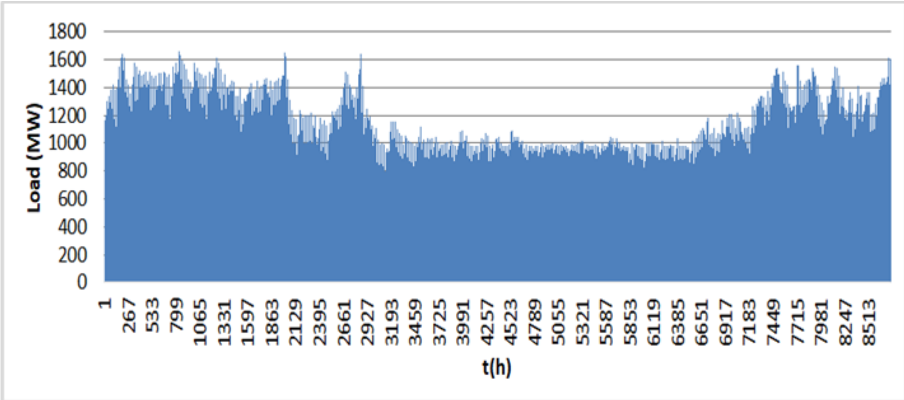

Figure XIX: Hourly load profile in 2025 – the MEPSO market area

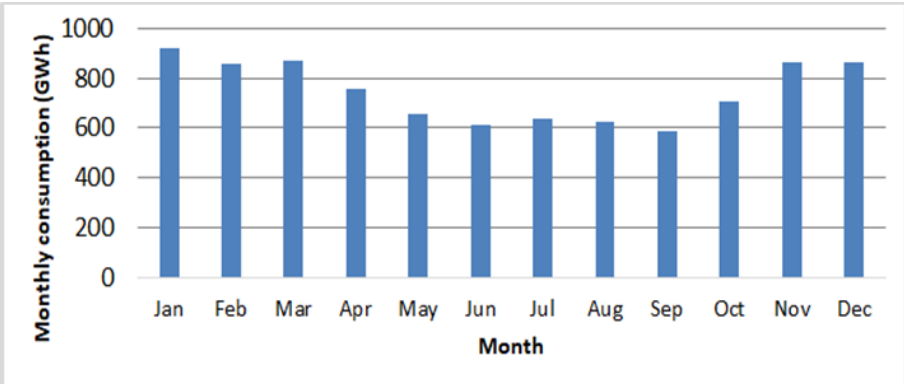

Figure XX: Monthly energy consumption (GWh) for 2025 – the MEPSO market area

Total consumption in 2025 in the baseline scenario is expected to be 8.93 TWh, while in the low demand scenario, with a reduced growth rate, total annual consumption would be 8.02 TWh (Table XXXV).

Table XXXV: Baseline and low demand scenarios in 2025 – the MEPSO market area

EMI Member	Demand in 2017 (TWh)	Baseline scenario		Low demand scenario	
		Growth rate from 2017 to 2025	Demand in 2025 (TWh)	Growth rate from 2017 to 2025	Demand in 2025 (TWh)
MK	7.2	2.73%	8.93	1.36%	8.02

The MEPSO market area – Production

In 2025, the MEPSO market area's hydro-thermal production mix will stay balanced, with 8% of RES in wind and solar power plants. Base load plants (lignite, hard coal) will still represent the largest group of thermal units in terms of installed capacities (Table XXXVI and Figure XXI).

Table XXXVI: Installed capacities per technology in 2025 – the MEPSO market area

Technology	Installed capacity (MW)
Thermal - lignite	699
Thermal - hard coal	120
Thermal – gas	317
Thermal - heavy oil	210
Hydro	694
Wind	100/150[5]
Solar	67/67[5]

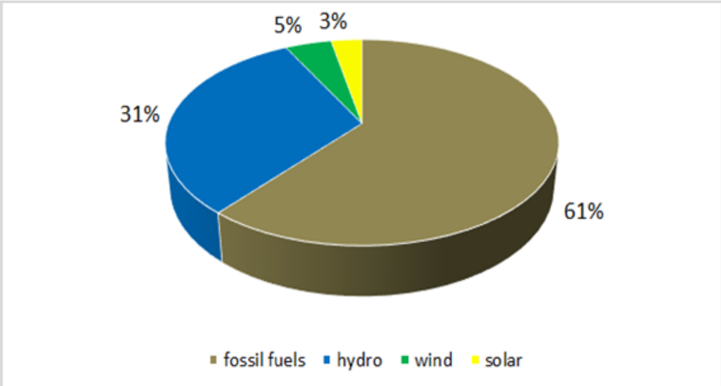

Figure XXI: Installed capacity per fuel type in 2025 – the MEPSO market area

Table XXXVII and Table XXXVIII present the average annual capacity factors for wind and solar power plants and the annual generations of all HPPs for different hydrological conditions, both provided by MEPSO.

Table XXXVII: Average wind and solar capacity factors for 1982, 1984 and 2007 – the 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 XXXVIII: Annual generation for all HPPs for dry, average and wet hydrology – the MEPSO market area

Annual generation (GWh)	Dry	Average	Wet
ROR	168	241	313
HPPs with reservoirs	861	1231	1600
Total	1029	1472	1913

The MEPSO market area – Network capacity

In terms of network capacity, there will be no major changes compared by present situation by 2025. Also there is no differences between the summer and winter regime. The border with the ADMIE/IPTO market area has the highest transmission capacity, while the border with the EMS market area has the smallest (Table XXXIX)

Table XXXIX: Network transfer capacities in 2025 – the MEPSO market area

NTC (MW) in 2025	Win/Aut	Sum/Spr
XK - MK	**325**	**325**
MK - XK	**200**	**200**
RS - MK	**325**	**325**
MK - RS	**200**	**200**
AL - MK	**400**	**400**
MK - AL	**600**	**600**
MK - GR	**650**	**1000**
GR - MK	**650**	**1000**
BG - MK	**500**	**500**
MK - BG	**400**	**400**

The CGES market area

The CGES market area – Demand

The forecasted peak load for 2025 is 899 MW, with a load factor of 60.84% (Figure XXII). In the winter (November - March), the highest monthly consumption, above 400 GWh is expected, while in summer (June - September), the forecasted monthly energy use is below 400 GWh (Figure XXIII).

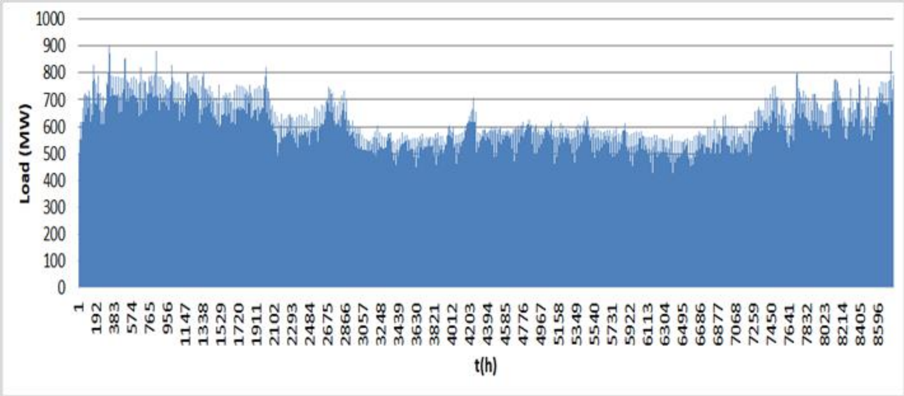

Figure XXII: Hourly load profile in 2025 – the CGES market area

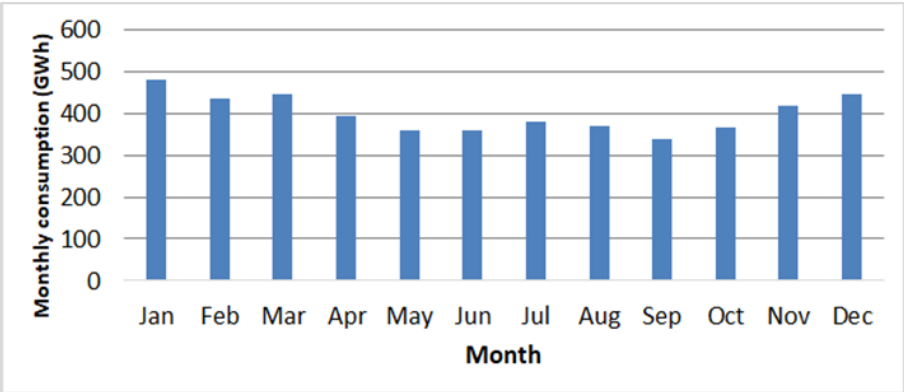

Figure XXIII: Monthly energy consumption (GWh) for 2025 – the CGES market area

Total consumption in the baseline scenario in the CGES market area is expected to be 4.78 TWh, while in the low demand scenario, with a lower growth rate, total annual consumption would be 4.04 TWh (Table XL).

Table XL: Baseline and low demand scenarios in 2025 – the CGES market area

EMI member	Demand in 2017 (TWh)	Baseline scenario		Low demand scenario	
		Growth rate from 2017 to 2025	Demand in 2025 (TWh)	Growth rate from 2017 to 2025	Demand in 2025 (TWh)
ME	3.4	4.35%	4.78	2.18%	4.04

The CGES market area – Production

In 2025, the highest share of installed generation in the CGES market area will be in HPPs, around 58%, and the TPP capacity share will be just 18%. In addition, we envisage 171 MW of wind and 300 MW of solar capacity, for a share of 33% in 2025 (Table XLI and Figure XXIV).

Table XLI: Installed capacities per technology in 2025 – the CGES market area

Technology	Installed capacity (MW)
Thermal - lignite	225
Hydro	708
Wind	171/243[5]
Solar	300/300[5]

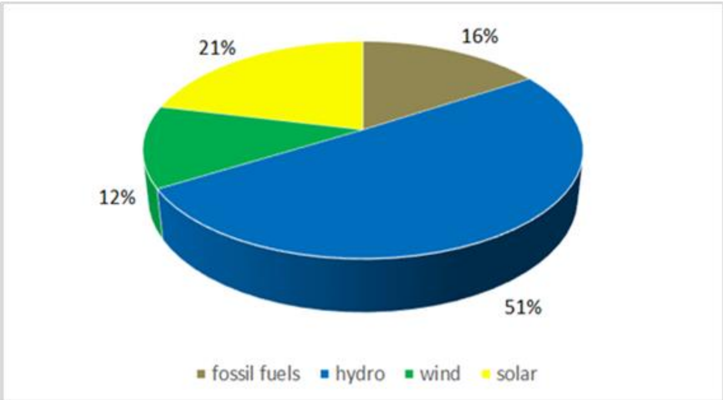

Figure XXIV: Installed capacity per fuel type in 2025 – the CGES market area

Average wind and solar capacities for relevant climatic years are given in Table XLII. Also, annual generation for dry, average and wet hydrology are given in Table XLIII. CGES provided monthly generation for average hydrology, and we have calculated the dry and wet generation of HPP, as usual, by multiplying normal generation with coefficients of 0.75 and 1.25, respectively. It is noted that all the CGES market area's HPPs contain reservoirs.

Table XLII: Average wind and solar capacity factors for 1982, 1984 and 2007 – the 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 XLIII: Annual generation for all HPPs for dry, average and wet hydrology – the CGES market area

Annual generation (GWh)	Dry	Average	Wet
ROR	0	0	0
HPPs with reservoirs	1451	1935	2419
Total	1451	1935	2419

CGES market area – Network capacity

In terms of network capacity, two major network reinforcements will have a high impact on the CGES market area. First, the commissioning of the HVDC link between the CGES market area and Italy will directly connect the region with the Italian electricity market. The second major project is the new interconnection between the CGES market area and EMS market area (OHL Bajina Basta – Pljevlja) which will increase the NTC values at the border, and facilitate the energy transit corridor towards Italy (Table XLIV).

Table XLIV: Network transfer capacities in 2025 – the CGES market area

NTC (MW) in 2025	Win/Aut	Sum/Spr
XK - ME	**300**	**300**
ME - XK	**300**	**300**
RS - ME	**300**	**300**
ME - RS	**300**	**300**
BA - ME	**600**	**600**
ME - BA	**600**	**600**
AL - ME	**500**	**500**
ME - AL	**500**	**500**
IT - ME	**600**	**600**
ME - IT	**600**	**600**

The TransElectrica market area

The TransElectrica market area – Demand

The TransElectrica market area is one of the largest in SEE, both in terms of load and production. The maximum peak load in the TransElectrica market area is expected to surpass 10 GW in 2025, with the minimum load expected to be around 4,400 MW (Figure XXV).

Data related to the TransElectrica market area's load profile in 2025 was delivered by the TSO (TransElectrica).

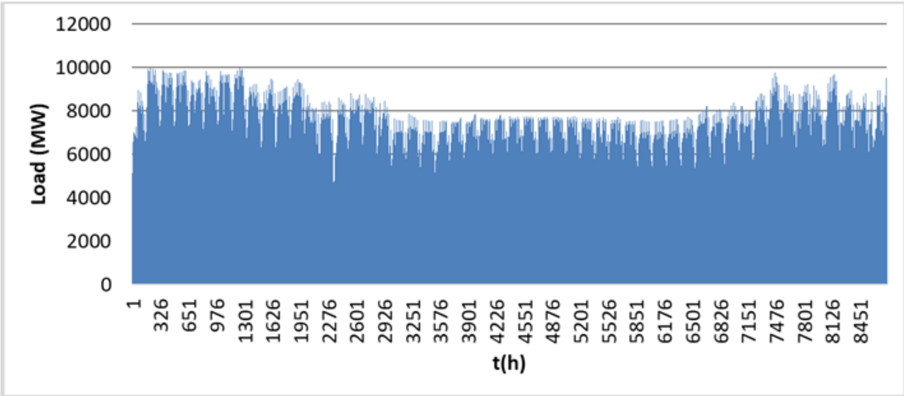

Figure XXV: Hourly load profile in 2025 – the TransElectrica market area

The highest monthly consumption is observed during the winter season – in months of January or December, while the lowest monthly consumption is present in September or June, depending on the climate conditions, as depicted in Figure XXVI.

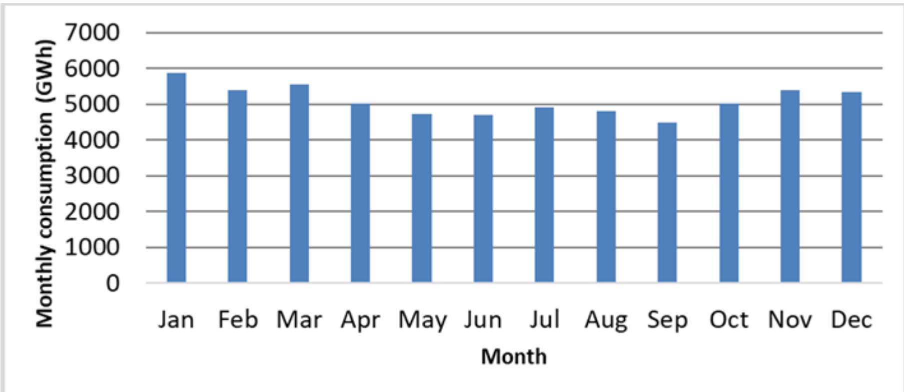

Figure XXVI: Monthly energy consumption (GWh) for 2025 – the TransElectrica market area

Total consumption in the baseline scenario is expected to be 62 TWh in 2025, while in the low demand scenario, with a reduced growth rate, it would be around 59 TWh (Table XLV).

Table XLV: Baseline and low demand scenarios in 2025 – the TransElectrica market area

EMI member	Demand in 2017 (TWh)	Baseline scenario		Low demand scenario	
		Growth rate from 2017 to 2025	Demand in 2025 (TWh)	Growth rate from 2017 to 2025	Demand in 2025 (TWh)
RO	56.8	1.08%	61.90	0.54%	59.30

The TransElectrica market area – Production

The dataset provided by the TSO omitted certain information regarding TPPs, such as heat rate, fuel price, variable O&M cost, CO_2 emission rate. We filled in the missing data related to TPPs from the TYNDP 2018 ENTSO-E database. Table XLVI provides data on the installed generation capacities in 2025 in the TransElectrica market area by technology.

Table XLVI provides data on installed capacity in the TransElectrica market area by 2025. Share of installed capacity in TPPs will be around 35% of total installed generation capacities. Nuclear power is prominent in the TransElectrica market area's generation mix: its share will be about 7% of installed power. Hydropower will also have a significant share – 33%.

Table XLVI: Installed capacities per technology in 2025 – the TransElectrica market area

Technology	Installed capacity (MW)
Thermal - lignite	3415
Thermal - gas	3002
Thermal - hard coal	620
Nuclear	1325
Hydro	6778
Wind	3500/4200[5]
Solar	1500/2000[5]
Biomass	250

Renewable power is expected to play a very significant role in the TransElectrica market area, as wind and solar power will have almost a 25% share of the mix in 2025. In specific, wind power plants will contribute with 17%, while solar power plants with 7% of generation capacities. Besides wind and solar, another renewable source will contribute to generation mix – biomass, with a share of 1%. Detailed representation of generation mix in the TransElectrica market area is given in Figure XXVII.

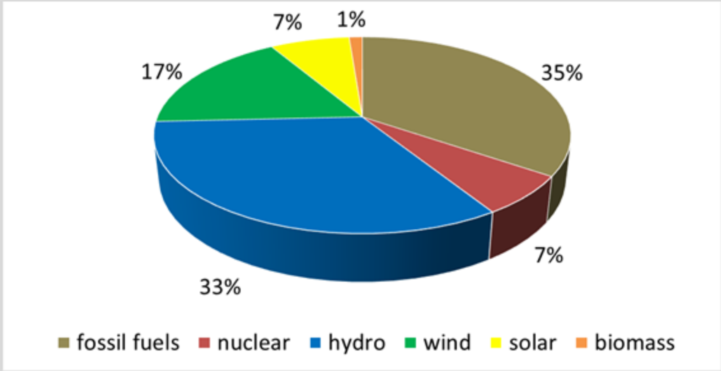

Figure XXVII: Installed capacity per fuel type in 2025 – the TransElectrica market area

On the basis of the TSO's hourly profiles of capacity factors for wind and solar generation, Table 51 shows the average capacity factors for different climatic years.

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

The TransElectrica market area – average wind and solar capacity factors			
Year	**1982**	**1984**	**2007**
Wind CF	21.32%	24.27%	23.77%
Solar CF	19.31%	18.82%	19.48%

The hydro generation for average, dry and wet hydrology was provided by the TSO (TransElectrica). The total annual generations for Run of River (ROR) and storage HPP (with reservoir) are given in Table XLVIII.

Table XLVIII: Annual generation for all HPPs for dry, average and wet hydrology – the TransElectrica market area

Annual generation (GWh)	Dry	Average	Wet
ROR	8297	10371	11408
HPPs with reservoirs	4443	5553	6109
Total	12740	15924	17517

The TransElectrica market area – Network capacity

By 2025, the TransElectrica market area's interconnections with neighboring countries will improve compared to the present, due to the nominal transmission capacity increase. Table 53 shows the NTCs for the TransElectrica market area's borders in 2025.

Table XLIX: Network transfer capacities in 2025 – the TransElectrica market area

NTC (MW) in 2025	Win/Aut	Sum/Spr
RS - RO	800	800
RO - RS	1000	1000
RO - BG	1100	1100
BG - RO	1200	1200
RO - HU	1100	1100
HU - RO	1000	1000

The EMS market area

The EMS market area – Demand

Forecasted consumption in the EMS market area (excluding KOSTT market area) is 37 TWh in 2025 (Table L), and the expected peak load is 5973 MW, with a load factor of 70.8% (Figure XXVIII). The highest monthly consumption is anticipated in the winter season (December, January), while the lowest consumption will occur from mid spring to early autumn (May - September), as shown in Figure XXIX.

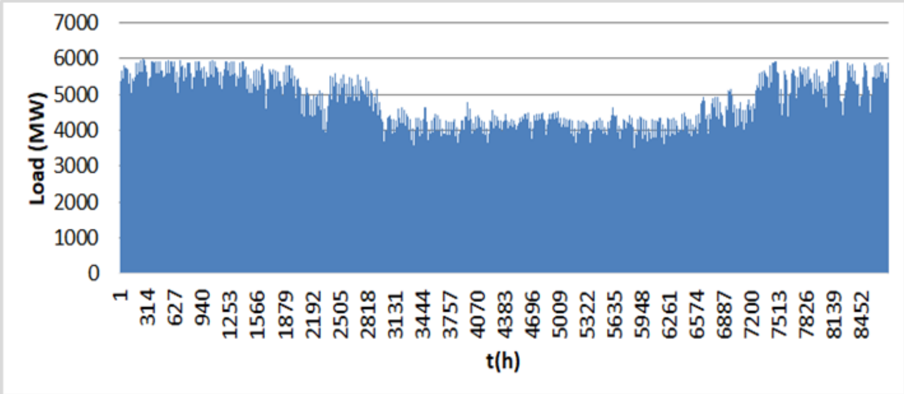

Figure XXVIII: Hourly load profile in 2025 – the EMS market area

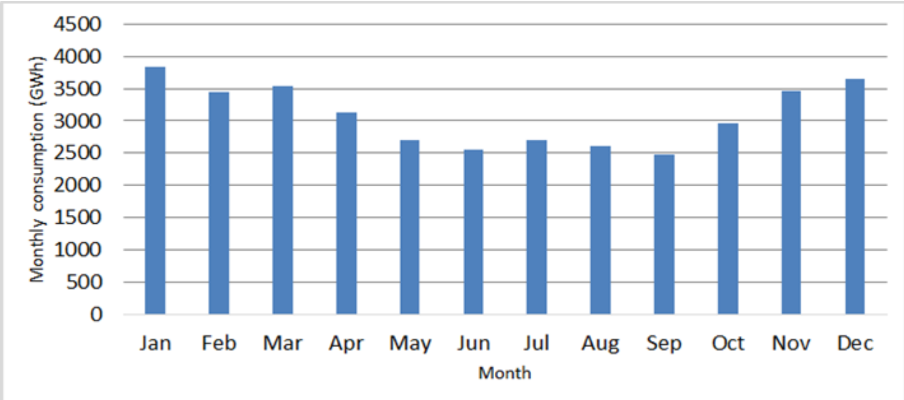

Figure XXIX: Monthly energy consumption (GWh) for 2025 – the EMS market area

Total consumption in the baseline scenario is expected to be 37.1 TWh, while in the low demand scenario, with a reduced growth rate, total consumption in 2025 would be 36 TWh (Table L).

Table L: Baseline and low demand scenarios in 2025 – the EMS market area

EMI member	Demand in 2017 (TWh)	Baseline scenario		Low demand scenario	
		Growth rate from 2017 to 2025	Demand in 2025 (TWh)	Growth rate from 2017 to 2025	Demand in 2025 (TWh)
RS	34.9	0.77%	37.1	0.39%	36

The EMS market area – Production

In 2025, the EMS market area production portfolio (excluding KOSTT market area) will still be largely a hydro-thermal mix. TPPs will account for about half of the total installed capacity, most fired with lignite. Renewable generation will account for around 14% of capacity, with 1,216 MW of wind generation, and only 10 MW of solar (Table LI and Figure XXX).

Table LI: Installed capacities per technology in 2025 – the EMS market area

Technology	Installed capacity (MW)
Thermal - lignite	4070
Thermal - gas	183
Hydro	3043
Wind	1216/1216[5]
Solar	10/200[5]

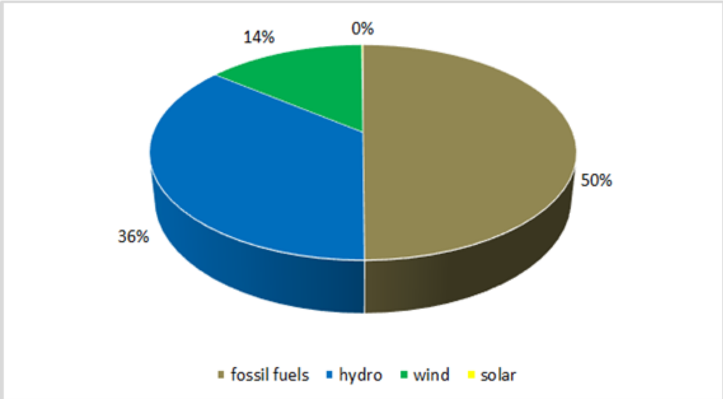

Figure XXX: Installed capacity per fuel type in 2025 – the EMS market area

The annual capacity factors for wind are based on our assessment, and we utilized solar capacity factors from a publicly available database[11], keeping in mind that capacity factors for the years 1982 and 1984 are presented by 2013 and 2009. We calculated capacity factors for wind using the corresponding capacity factors for TransElectrica market area, adjusted using the ratio between the average capacity factors for the TransElectrica market area and the EMS market area for 2014 taken from the public database[12] (Table LII).

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

EMS market area – average wind and solar capacity factors			
Year	**1982**	**1984**	**2007**
Wind CF	18.82%	21.42%	20.98%
Solar CF	14.57%	14.22%	14.94%

[11] https://www.renewables.ninja/
[12] https://www.renewables.ninja/

We have taken generation for average hydrology per power plants from the SECI study, while generations for dry and wet hydrology have been calculated by multiplying the average hydrology values with coefficients 0.9 and 1.1, respectively, encompassing the specifics of hydropower plants in the EMS market area and possible levels of their generation (Table LIII).

Table LIII: Annual generation for all HPPs for dry, average and wet hydrology – the EMS market area

Annual generation (GWh)	Dry	Average	Wet
ROR	891	990	1089
HPPs with reservoirs	7943	8826	9709
Total	8834	9816	10798

Table LIV provides data regarding modeling of PSHPP Bajina Basta in Antares as provided by EMS.

Table LIV: PSHPP data – the EMS market area

Name	Number of units	Pgen (MW)	Ppump (MW)	Efficiency
PSHPP Bajina Basta	2	614	560	75%

The EMS market area – Network capacity

In terms of network capacity, major projects to interconnect the EMS market area with the NOSBiH market area and the CGES market area will increase the NTC values in 2025 at the observed borders and facilitate the energy transit corridor towards Italy (Table LV).

Table LV: Network transfer capacities in 2025 – the EMS market area

NTC (MW) in 2025	Win/Aut	Sum/Spr
RS - RO	800	800
RO - RS	1000	1000
BG - RS	400	400
RS - BG	400	400
RS - MK	325	325
MK - RS	200	200
RS - HR	500	500
HR - RS	500	500
RS - HU	600	600
HU - RS	600	600
RS - XK	300	300
XK - RS	400	400
RS - ME	300	300
ME - RS	300	300
RS - BA	600	600
BA - RS	600	600

The ELES market area

The ELES market area – Demand

The ELES market area is one of the smaller ones in the region: the peak hourly load in 2025 is expected to be slightly above 2,300 MW, with minimum load just below 1,000 MW (Figure XXXI). The data related to the ELES market area's hourly load profile in 2025 was taken from TYNDP 2018 scenario Best Estimate 2025.

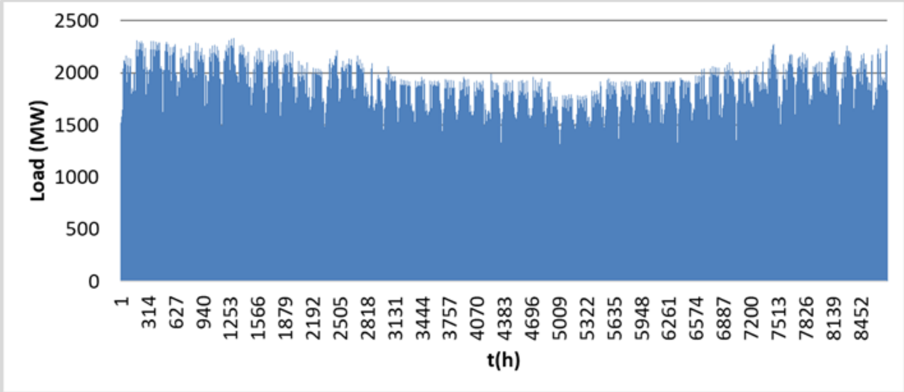

Figure XXXI: Hourly load profile in 2025 – the ELES market area

Regarding the monthly pattern, the ELES market area's monthly loads are relatively stable throughout the year, ranging from 1,160 GWh in June to 1,400 GWh in January (Figure XXXII).

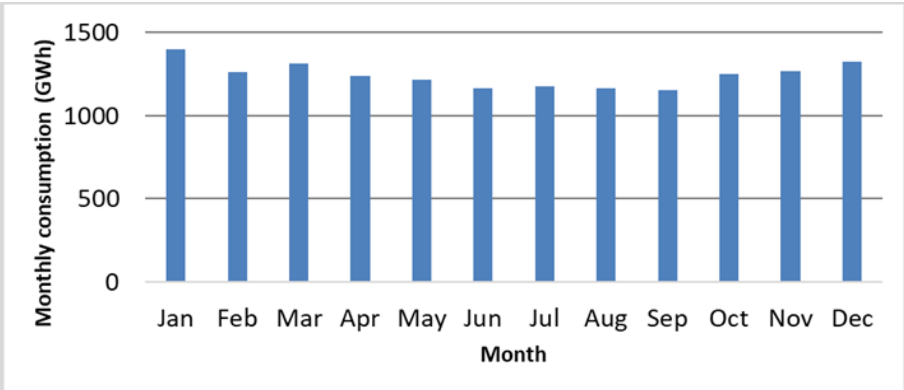

Figure XXXII: Monthly energy consumption (GWh) for 2025 – the ELES market area

Total consumption in the baseline scenario is expected to be 15 TWh, while in the low demand scenario, with a reduced growth rate, total annual consumption would be around 14.6 TWh (Table LVI).

Table LVI: Baseline and low demand scenarios in 2025 – the ELES market area

EMI member	Demand in 2017 (TWh)	Baseline scenario		Low demand scenario	
		Growth rate from 2017 to 2025	Demand in 2025 (TWh)	Growth rate from 2017 to 2025	Demand in 2025 (TWh)
SI	14.2	0.77%	15.10	0.39%	14.64

The ELES market area – Production

The dataset provided by the TSO omitted certain information regarding some TPPs, such as fuel price, variable O&M cost, as well as generation of HPP (dry and wet hydrology). We filled in the missing data related to TPPs from the TYNDP 2018 ENTSO-E database. Table LVII provides data on installed generation capacities in 2025 by technology.

Table LVII: Installed capacities per technology in 2025 – the ELES market area

Technology	Installed capacity (MW)
Thermal - lignite	844
Thermal - gas	618
Nuclear	696
Hydro	1631
Wind	20/80[5]
Solar	361/578[5]

Regarding technologies, the largest share of installed power in the ELES market area will be in HPPs at 1,600 MW. TPPs will participate with approximately 35%. In 2025, 17% 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: there will be 361 MW in solar power and 20 MW in wind power (9% and 0.5% share of installed power, respectively), as depicted in Figure XXXIII.

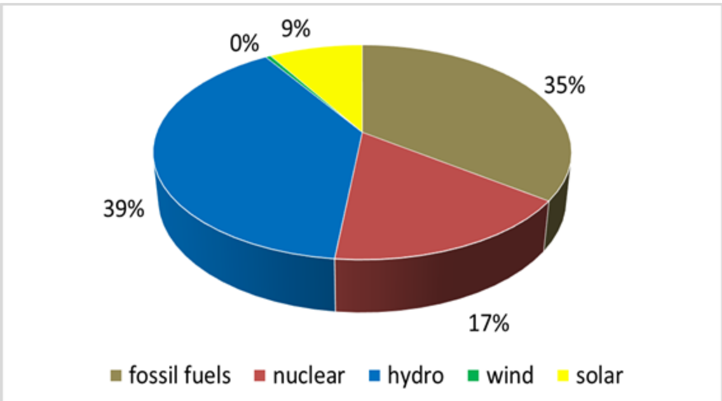

Figure XXXIII: Installed capacity per fuel type in 2025 – the ELES market area

Since hourly capacity factors for wind and solar generation were not available, we used a dataset related to capacity factors for ELES market area from a publicly available database – Renewables.ninja. However, hourly data from Renewables.ninja seemed unrealistic for the ELES market area, so hourly capacity factors from Renewables.ninja were adjusted to reach average yearly capacity factors reported by ELES. Table LVIII shows the average annual capacity factors for wind and solar plants.

Table LVIII: Adopted average wind and solar capacity factors for 1982, 1984 and 2007 – the 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%

Regarding hydro generation, the TSO provided data for average hydrology. Hydro generation in dry and wet hydrological conditions is assumed to be ±25% of the generation in average conditions. The forecasted annual generation of HPPs in the ELES market area for different hydrological conditions is given in Table LIX.

Table LIX: Annual generation for all HPPs for dry, average and wet hydrology – the ELES market area

Annual generation (GWh)	Dry	Average	Wet
ROR	3148	4197	5247
HPPs with reservoirs	0	0	0
Total	3148	4197	5247

Table LX provides data regarding modeling of PSHPPs in the ELES market area.

Table LX: PSHPP data – the ELES market area

Name	Number of units	Pgen (MW)	Ppump (MW)	Efficiency
PSHPP Soča	1	185	180	75%
PSHPP Drava	2	420	354	75%

The ELES market area – Network capacity

By 2025, no significant new capacity is expected in SI-HR interconnection. At present, an interconnection between the ELES market area and the Hungarian market area does not exist, and it is planned to be commissioned in 2021. NTCs for the ELES market area's borders in 2025 are given in Table LXI.

Table LXI: Network transfer capacities in 2025 – the ELES market area

NTC (MW) in 2025	Win/Aut	Sum/Spr
HR - SI	1500	1000
SI - HR	1500	1100
SI - HU	1200	1200
HU - SI	1200	1200

APPENDIX II: SEE REGIONAL MARKET MODEL IN ANTARES

Starting with the database of collected data, we adopted the following approach with regard to the countries and market areas being modeled:

- We modeled all countries/market areas, except the Hungarian market area, on a plant-by-plant level of detail
- We modeled the Hungarian market area by technology clusters (hydro by river basin, thermal by fuel type, nuclear, RES)
- We modeled Turkey, Central Europe and Italy as external spot markets where the market clearing price series is insensitive to fluctuations of prices in SEE; transfers are constrained with transmission capacity.

The EMI project performed the SEE regional market simulations using the Antares software tool.

Antares in brief

The software (SW) tool called Antares (A New Tool for Adequacy Reporting of Electrical Systems) is a tool developed by RTE (the French TSO), and since the middle of 2018, is a SW tool with open and free access.

Antares is a simulation and optimization tool that combines electricity market modeling (economic dispatch) while achieving supply-demand equilibrium under constraints, using Monte-Carlo simulations. The model simulates the market mechanisms using a European zonal approach, and taking into account Europe's interconnection exchanges.

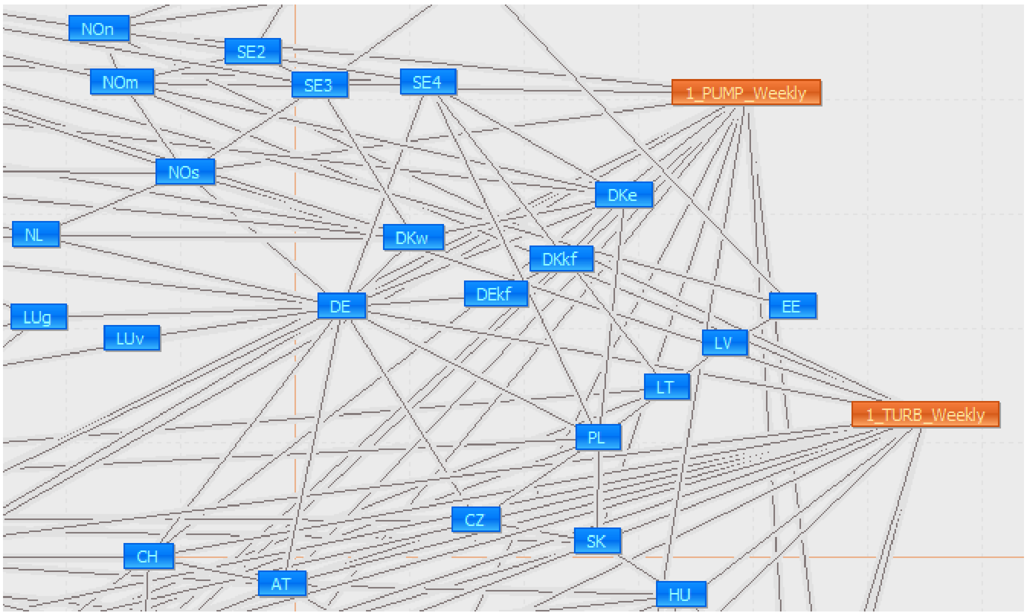

Figure XXXIV: Presentation of European zones in Antares

Antares is a ***Monte-Carlo*** simulator, which means that it defines sets of plausible operating combinations by carrying out correlated or random draws that reproduce various events that can affect the system operation throughout the year. These events include climatic conditions that influence load, as well as wind and solar generation; different hydrology that influences the level of hydro generation; and different levels of maintenance and outages that will influence the availability of thermal and nuclear plants.

Given the size and complexity of the overall problem, each Monte-Carlo year is seen as a succession of weekly sub-problem optimizations. The kernel of the software is a linear solver which, once fed with adequate assumptions (availability and costs of power plants, demand level, etc.) computes operating set-points for the whole system (optimal weekly unit-commitment and hydro-thermal scheduling, with an hourly resolution).

Economic dispatch of the region's power generation is based on the model's assumption of a perfect market. This dispatch aims to minimize the overall system cost [1.1], subject to constraints such as power plant availability, interconnection's properties, defined relations between different flows as additional constraints, etc. in this equation:

$$Min(\Omega) = \sum_t \sum_g \sum_z B(t,g,z) \times Q(t,g,z) \qquad [1.1]$$

Where:

B(t,g,z) is the bid of the power plant G in zone z at hour t [Euro/MWh]

Q(t,g,z) is the generated power in power plant G in zone z at hour t [MWh]

The bids are defined as Short Run Marginal Costs (SRMC) that includes fuel costs, variable operating costs, maintenance costs, CO_2 emission tax. Investment costs are not included.

The time span used is of one year and the time resolution is one hour in order to be consistent with the resolution used in wholesale electricity market.

Modeling of the SEE region

Each of the modeled countries have been analyzed as a single node, i.e. no inter-country lines are modeled. All the generators within each country/market area are connected to this aggregate node. The nodes are connected with simulated lines whose maximum capacity is equal to the nominal transfer capacities (NTCs) between the two areas. The Antares model solves this "transportational" problem, while respecting the interconnection capacity limits.

The EMI included all the relevant generator data in the model (e.g. minimum stable level, maximum net capacity, min up and down time, etc.). This is especially important for the NPPs and large TPPs that have a limited range of flexibility. We modeled the market bid and marginal costs for each thermal unit as the same figure, assuming perfect market operation. The Monte-Carlo approach enables the EMI to simulate several situations for the availability of thermal power plants, taking into account their given outage rates and durations (both: forced and planned).

The simulation time step is 1 hour, and the simulation span is one year.

The wind power, solar power and load are modeled with the hourly time series for three climatic years, as given in the input data. This means the total wind and solar power production result from the resource limits embedded in the input time series. The Monte-Carlo approach enables the simulation of several load/wind/solar time series, with different availabilities of the thermal power plants.

We modeled each hydro power plant, taking into account their corresponding maximum capacity and average monthly generation. We distinguish between run-of-river (ROR) plants, and those with reservoirs. We model ROR plants with a flat hourly generation profile that corresponds to its given monthly generation, and model HPPs with reservoirs to enable the flexible dispatching of these units, while respecting their technical constraints (max capacity, biological minimum, reservoir size). We aggregate some HPPs. Given that their operation is subject to restrictions of hydrology, we can safely represent several small RoR HPPs on the same river with a single HPP that sums (aggregates) their total production.

As stated above, the EMI modeled the neighboring countries/zones with a reduced level of detail. This approach reflects the influence of neighboring countries, while keeping the model complexity on a tractable scale. This means that we aggregated the Hungarian TPPs per technology, with particular attention to NPP Pakš, since their operation has a significant impact on the SEE regional power system.

Turkey, Central Europe and Italy are modeled as three spot market nodes external to the modeled system, with possible exchanges to the SEE region constrained by the relevant NTC values. We model the price movement in these three nodes using existing price profiles and the expected price levels in 2025, i.e., the price movement time series in these nodes belongs to input data and the exchange is the result of simulations.

The EMI developed different regional analyses, focusing on different parameters and scenarios:

- Market integration and corresponding **NTC values** (separated as today, partially coupled, fully coupled)
- Level of **installed RES capacities** (baseline scenario, high scenario)
- Level of **consumption** (baseline scenario, low scenario)
- **Hydrology conditions** (average in the baseline scenario, plus a dry hydrology scenario)
- Inclusion of **CO_2 tax** (all countries assumed to be in the **EU ETS**)