The Southeast European power system in 2030

Flexibility challenges and benefits from regional integration

ANALYSIS

Agora Energiewende

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Preface

Dear Reader,

Energy systems in Europe are undergoing a fundamental transformation. As fossil fuels are increasingly phased out, renewables and energy efficiency will become the backbones of the new energy system. As early as 2030, 55% of the electricity being generated in Europe will come from renewables.

While this transition will help to mitigate global warming, it also makes economic sense. The cost of wind power and solar PV has dropped significantly in recent decades, and further cost reductions are anticipated. Power systems in Southeast Europe (SEE), being largely dependent on lignite-fired electricity, will also undergo dramatic change. By 2030, renewables will be responsible for some 50% of power output in SEE, with wind and solar accounting for two-thirds of this generation.

As wind and solar are weather-dependent, their production patterns are variable. Power systems will have to cope with this variable generation by becoming much more flexible. Moreover, in order to ensure security of supply at the lowest possible cost, stronger physical integration of power systems and regional cooperation will be key.

To better understand the issues at stake, we have commissioned experts from REKK to examine potential developments up to 2030 in SEE: What kinds of flexibility requirements arise from the projected growth of wind and PV? To what extent can further power market integration within SEE and beyond help to meet this challenge? And will power systems still possess sufficient reserve margins to guarantee security of supply in critical situations?
I hope you find this study an inspiring and enjoyable read. Your comments are of course welcome.

Yours sincerely,

Patrick Graichen
Executive Director of Agora Energiewende

Key findings at a glance:

1. **Renewables will provide 50% of SEE power demand in 2030. The European energy transition is underway.** By 2030, renewables will account for 55% of power generation in Europe, and 50% of power generation in SEE. Nearly 70% of renewable power in SEE will stem from wind and solar, given the excellent resource potential of these renewables in the region.

2. **Cross-border power system integration will minimise flexibility needs. Wind and solar pose challenges for power systems due to their variable generation. But weather patterns differ across countries.** For example, wind generation can fluctuate from one hour to the next by up to 47% in Romania, whereas the comparable figure for Europe is just 6%. Moving from national to regional balancing substantially lowers national flexibility needs. Increased cross-border interconnections and regional cooperation are thus essential for integrating higher levels of wind and PV generation.

3. **Conventional power plants will need to operate in a flexible manner. For economic reasons, hard coal and lignite will provide less than 25% of SEE power demand by 2030.** Accordingly, conventional power plants will need to flexibly mirror renewables generation: When renewables output is high, conventionals produce less, and when renewables output is low, fossil power plants increase production. Flexible operations will become an important aspect of power plant business models.

4. **Security of supply in SEE power systems with 50% RES is ensured by a mix of conventional power plants and cross-border cooperation.** The available reserve capacity margin in SEE will remain above 35% in 2030. More interconnectors, market integration and regional cooperation will be key factors for maximising national security of supply and minimising power system costs. SEE can be an important player in European power markets by providing flexibility services to CEE in years of high hydro availability.

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Executive Summary

This report takes a deeper look at the future of regional market integration for power systems with high shares of wind and solar in Southeast Europe (SEE). Because these technologies vary in output depending on the weather, they bring an increased need for flexibility services in the power system. Further integration of European power markets is a crucial enabler of flexibility.

This report assesses in detail the following questions: What kinds of flexibility requirements arise from the projected growth of wind and PV in SEE? To what extent can further power market integration within SEE and beyond help meet those requirements? Do power systems possess sufficient reserve margins to guarantee security of supply in critical situations?

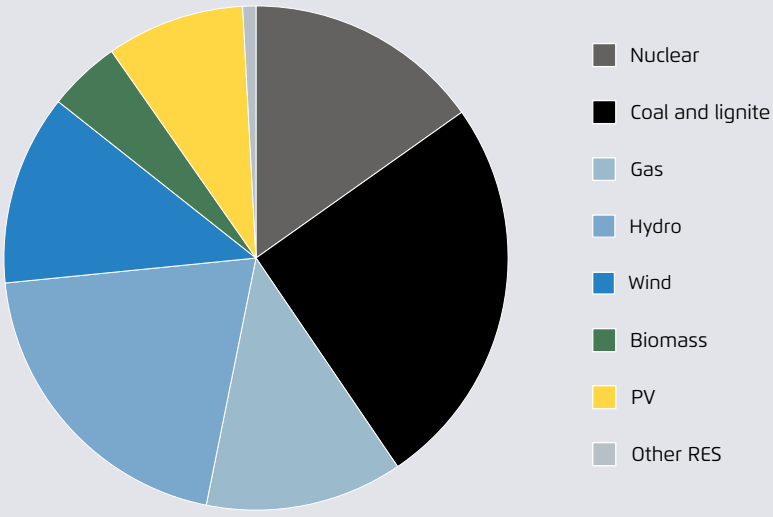
The SEE power system in 2030: Renewables as the main generation source

In view of the recently adopted EU 2030 targets for climate and energy, all European power systems are about to embark on a major transition. By 2030, an average of 57% of electricity in Europe's power grids will come from renewable energy sources[1]. For Southeast Europe (SEE), this means a RES-E share of 50% in 2030 (see Figure ES 1).[2] A factor accelerat-

1 See Agora Energiewende (2019): European Energy Transition 2030: The Big Picture. Ten Priorities for the next European Commission to meet the EU's 2030 targets and accelerate towards 2050.

2 In line with the overall European energy targets, the recent SEERMAP project has demonstrated that the deployment of renewable capacity in the EU SEE and Western Balkans is not only feasible but also has several advantages over fossil fuel-based investment. See http://rekk.hu/analysis-details/238/south_east_europe_electricity_roadmap_-_seermap for more details.

Generation mix in SEE in 2030 — Figure ES 1



SEERMAP Decarbonization Scenario; REKK (2017)

ing this transition is that roughly 50% of the region's existing coal and lignite generation capacity will need replacement by 2030 due to age and noncompliance with emission standards.

Solar photovoltaics (PV) and wind power – driven by significant cost reductions – will contribute to more than half of the RES-E production in Europe in 2030. For SEE, wind and PV will contribute some 65% to RES-E generation. Because wind and solar depend on weather, future power systems will have fundamentally different generation patterns from those observed today, significantly increasing the need for flexibility in the non-intermittent part of the power system. Regional cooperation and cross-border power system integration offer important ways forward in meeting future flexibility requirements.

Regional integration helps avoid RES curtailment and enables geographical smoothing of vRES

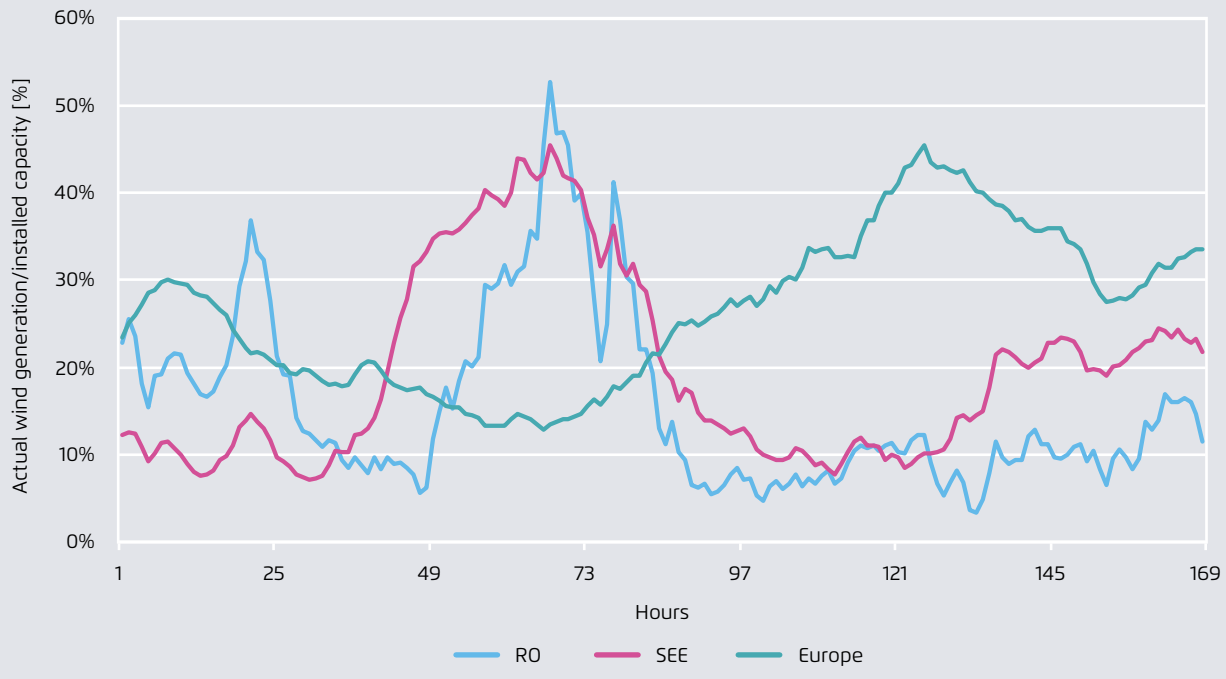
Based on our modelling, curtailment will not exceed 500 GWh a year in 2030,[3] and it will remain zero in the SEE region. The main reasons for the low level of vRES curtailment are the availability of hydro resources in the region that can satisfy flexibility needs in the power system, the availability of interconnectors offering flexibility potential through imports and exports and a low correlation between RES feed-in across borders.

We observe a very different cross-country pattern in wind generation easing vRES system integration. In

3 This corresponds to 0.014% of European power demand.

Time series of onshore wind power generation in a simulation for the first week of 2030 at different levels of aggregation

Figure ES 2



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the SEE region, wind speeds show weak correlation, ranging from 11% to 46%.[4] These fairly low correlations suggest that wind generation would not peak at the same time within the region; rather, it would be dispersed over time and across the countries in the region. It also suggests that the region would follow a different wind generation pattern from northern European countries, which means that wind production would not peak at the same time in the wider European region (see Figure ES 2).[5] For example, in Romania the maximum change of wind generation from one hour to the next is 47%, while the European-wide maximum change is only 6%.

Renewables generation and its consequences for conventional power plants

Both in Europe and in the SEE region, the 2030 scenario shows a more flexible utilization of power plants based on an increase in the number of start-ups per unit. This is a consequence of a lower utilization of conventional power plants due to the increased generation of variable RES and the deteriorating economic performance of coal and lignite plants. Climbing fossil-fuel costs, carbon prices and increasing investment costs place fossil-fuel-fired plants at the end of the merit order curve, resulting in a lower number of operation hours. This impact is further amplified by the growing production of zero-cost PV and wind generation, which on account of the "merit order effect" will supplant more and more fossil fuel plants from the pool of generators. Even though the number of start-ups will increase, by 2030 the total start-up costs as a share of variable generation costs will only amount to 1% in both the EU and in SEE (see Table ES 1).

4 This confirms earlier research testing the correlation of wind power feed-in between the countries of the Pentalateral Energy Forum (Austrian, Belgium, France, Germany, Luxembourg, the Netherlands, Switzerland) where correlation coefficients ranged from 24% (Austria and Belgium) to 66% (Luxembourg and Belgiun). For more details, see Fraunhofer IWES (2015): The European Power System in 2030: Flexibility Challenges and Integration Benefits. An Analysis with a Focus on the Pentalateral Energy Forum Region. Analysis on behalf of Agora Energiewende.

5 For example, Grams C. et. al. (2017) find that balancing future wind capacity across regions – deploying slightly more capacity in the Balkans than at the North Sea, say – would eliminate most wind production output variations, better maintain average generation and increase fleet-wide minimum output. See Grams et al (2017): Balancing Europe's Wind-Power output through Spatial Deployment Informed by Weather Regimes. Nature Climate Change.

Fossil fuel-based dispatchable power plants and the cost of start-ups in 2017 and 2030. Table ES1

		Number of units	Number of start-ups	Number of start-ups per unit	Total variable costs, m€	Total start-up costs, m€	Start-up costs/ total costs
Europe	**2017**	2202	14365	6.5	70636	721	1.02%
	2030	1522	13245	8.7	77664	906	1.17%
SEE	**2017**	167	441	2.6	4443	24	0.54%
	2030	89	798	9.0	5824	60	1.04%

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Utilization rates for different power plant technologies, 2017 and 2030. Table ES 2

		SEE			Europe		
		2017	2030	Change	2017	2030	Change
Utilization rate	Nuclear	84.8%	85.2%	**0.3%**	79.2%	81.0%	**1.7%**
	Natural gas	7.5%	39.9%	**32.4%**	27.0%	31.2%	**4.1%**
	Hard coal	20.2%	33.8%	**13.5%**	36.2%	46.1%	**9.9%**
	Lignite	77.6%	63.3%	**-14.4%**	80.4%	68.4%	**-12.0%**
	HFO	0.1%	1.3%	**1.2%**	4.5%	0.9%	**-3.7%**
	LFO	0.0%	0.0%	**0.0%**	7.3%	0.5%	**-6.8%**

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At the same time, the utilization rates of the different types of power plants will have changed significantly by 2030, with the utilization of natural gas plants climbing to 40% from 7.5% in 2017 and the utilization of hard coal-fired plants growing from 20% to 34% in the SEE region. The utilization of lignite-fuelled plants is projected to fall in Europe and in the SEE region, down from 81% to around 68%, due to deteriorating economic performance and reduced operating hours (see Table ES 2).

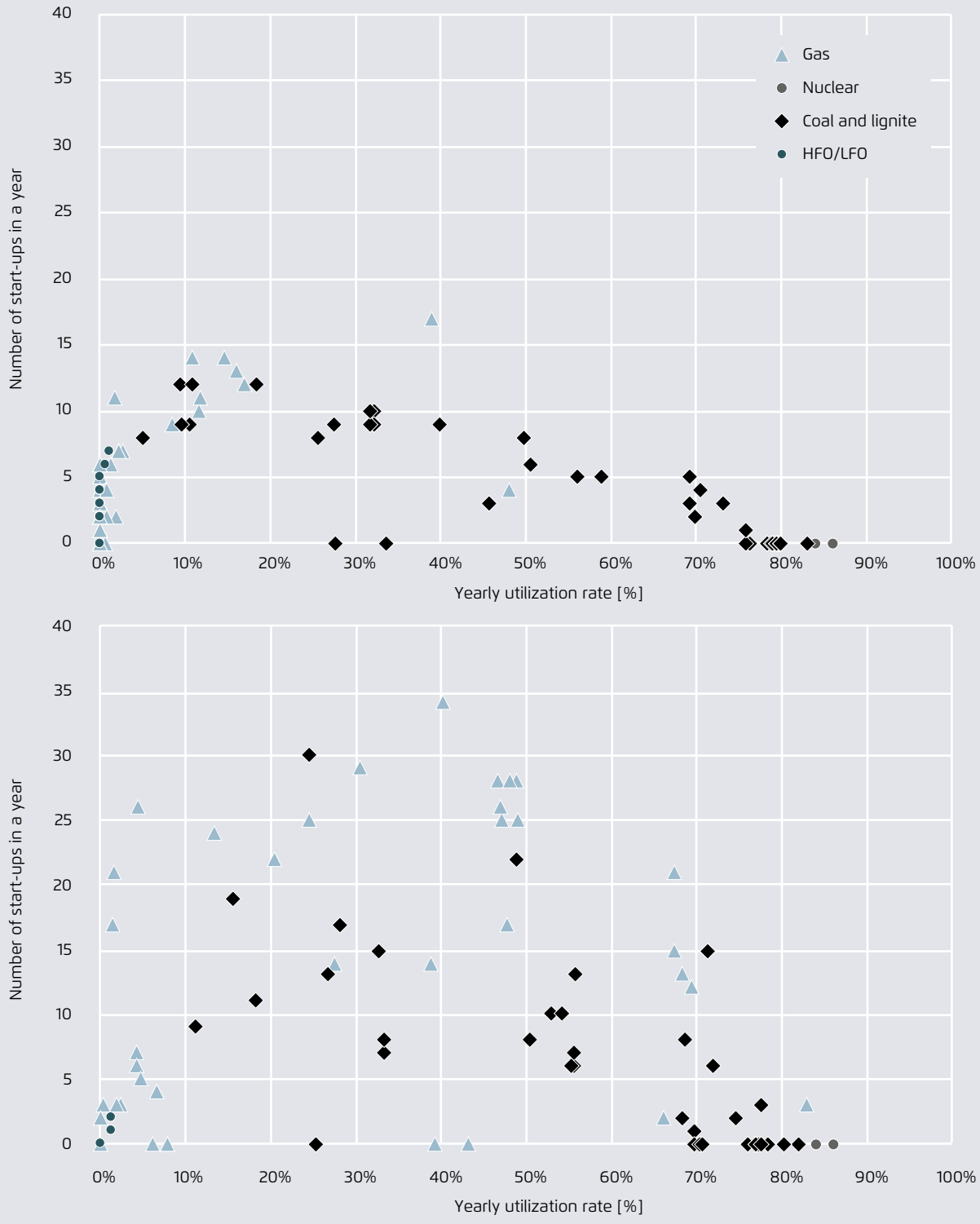
The most important change between 2017 and 2030 is that more and more power plants will be operated in "peak load" mode: natural gas power plants with low yearly average utilization rates and a high number of start-ups (up to 35 times/year). For comparison, the highest number of modelled start-ups for a given unit in 2017 was less than 20 in SEE. By 2030 more than half of the gas-fired units will actively participate in the intraday and balancing markets. The utilization structure of coal-, lignite- and HFO-LFO-fuelled plants will change similarly by 2030 – increasingly operating in a "flexibility services mode". This confirms their changing role and utilisation pattern in the future electricity system: they will provide more system balancing and flexibility services and receive more of their income from short-term power markets instead of from baseload energy sold on the futures and day-ahead markets (see Figure ES 3).

Security of supply: Sufficient reserve margins in SEE for a RES-E share of 50%

The amount of available upward reserve capacities in 2030, though lower than in 2017, will not fall below 5 GW in 2030 (12% of the regional peak load). These reserve capacities can step in if demand unexpectedly rises in real-time or if generation unexpectedly drops in real-time (e.g. due to a power plant outage or lower than forecasted RES generation). In the vast majority of hours, upward reserve capacities will not drop below 20 GW in 2030. General evaluation criteria indicate that a minimum of 5–10% of consumption is needed for upward reserve capacity to guarantee security of supply. By these lights, the SEE region will have a sufficient level of supply security in 2030.

Yearly average utilization rates and number of start-ups (per year) on a unit level in the SEE region in 2017 (above) and 2030 (below)

Figure ES 3



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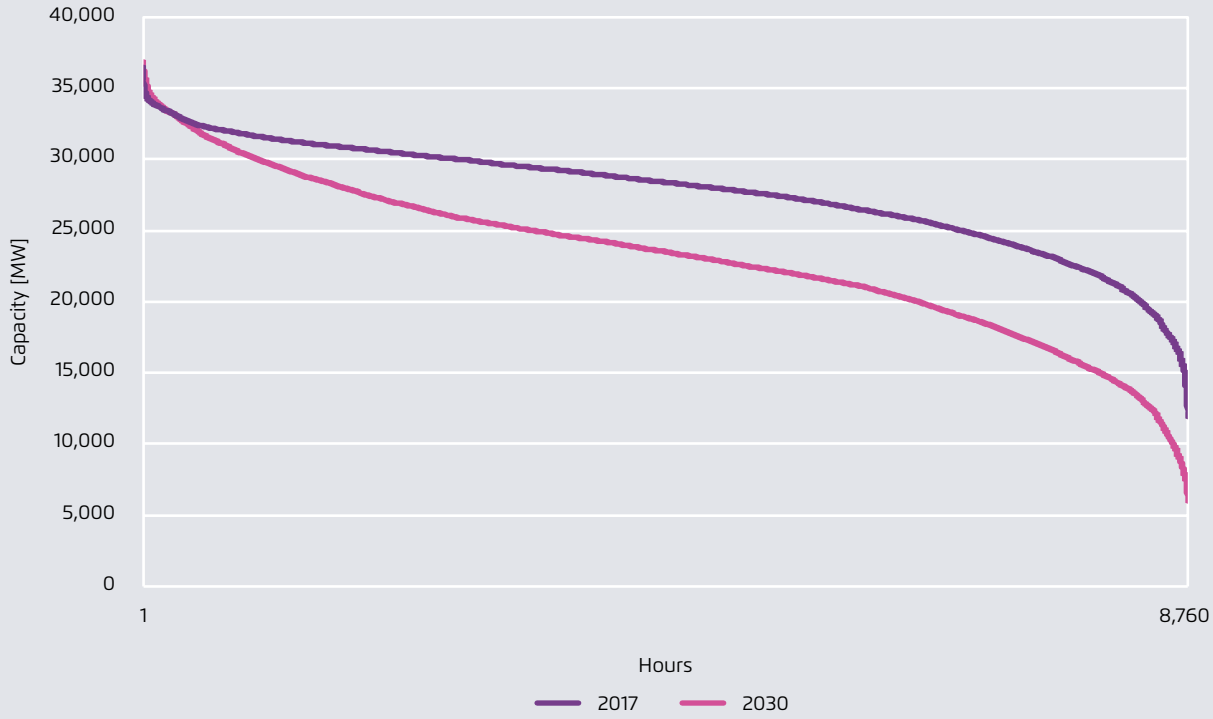
Total available upward reserve in the SEE region, in all hours of 2017 and 2030 Figure ES 4



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The total available downward reserve capacity for all hours of the year will increase by 2030, mostly because of the deployment of RES and natural gas plants, both of which provide downward regulation. The minimum downward reserve capacity will be ca. 11 GW in 2030 (27% of the regional peak load).

The number of hours with missing production will be very low in 2030. The scenario showed hours with missing production in Albania, Kosovo and North Macedonia. The missing production levels occur in one or two hours of the year, which indicate very low levels of load-shedding requirements. The typical security of supply standards in the EU range from three to six hours of loss of load expectation.

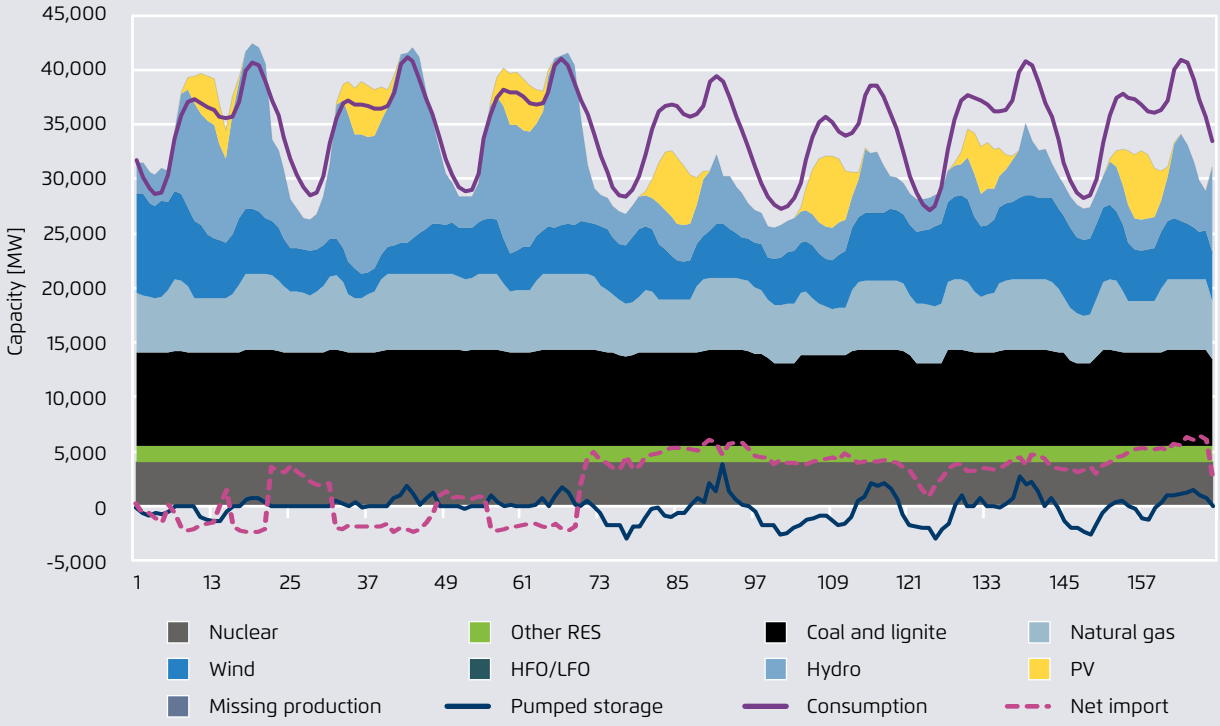
The results of missing production levels and low cross-border correlation of vRES feed-in emphasize the importance of regional cooperation and the availability of sufficient interconnection capacity between countries. Increasing interconnection levels between the countries can eliminate the missing production hours entirely, because countries with this problem can rely on imported electricity from neighbouring power systems.

Security of supply: Peak demand can be met in the winter season

To illustrate the daily operations of the 2030 power system in SEE, we describe **a week in winter** where the remaining capacity (defined as the sum of spinning and non-spinning reserve capacity and non-utilized import capacity) is lowest.

Unlike today, the natural gas-based electricity generation patterns of 2030 will change from peak-load

Electricity generation and demand in the SEE region for the critical week in winter in 2030 in MW Figure ES 5



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following to steadier generation because wind and PV output remains fairly low in the critical week. (Wind and PV generation levels will nearly double compared to 2017, however.) Consumption peaks will mostly be managed by increased hydro utilization and increased net imports, whose greater potential derives from increasing NTC levels. In the first half of the critical week, net imports will serve as "gap-fillers" while in the second half of the week they will be utilized on a more constant basis (see Figure ES 5).

In 2030, the reserve margin will only occasionally reach 100%, while in peak hours it will still be 40–60%, which represents a sufficient level of reserves. Due to the increased use of renewables and intermittent generation, production will be more volatile when compared with 2017, which means that the need for reserves will be more pronounced in some hours. The higher volatility in production is indicated by the steeper "ramp-ups" and "ramp-downs" of the blue area in Figure ES 6. Nonetheless, all electricity demand will be met in the region (unserved energy=0 GWh).

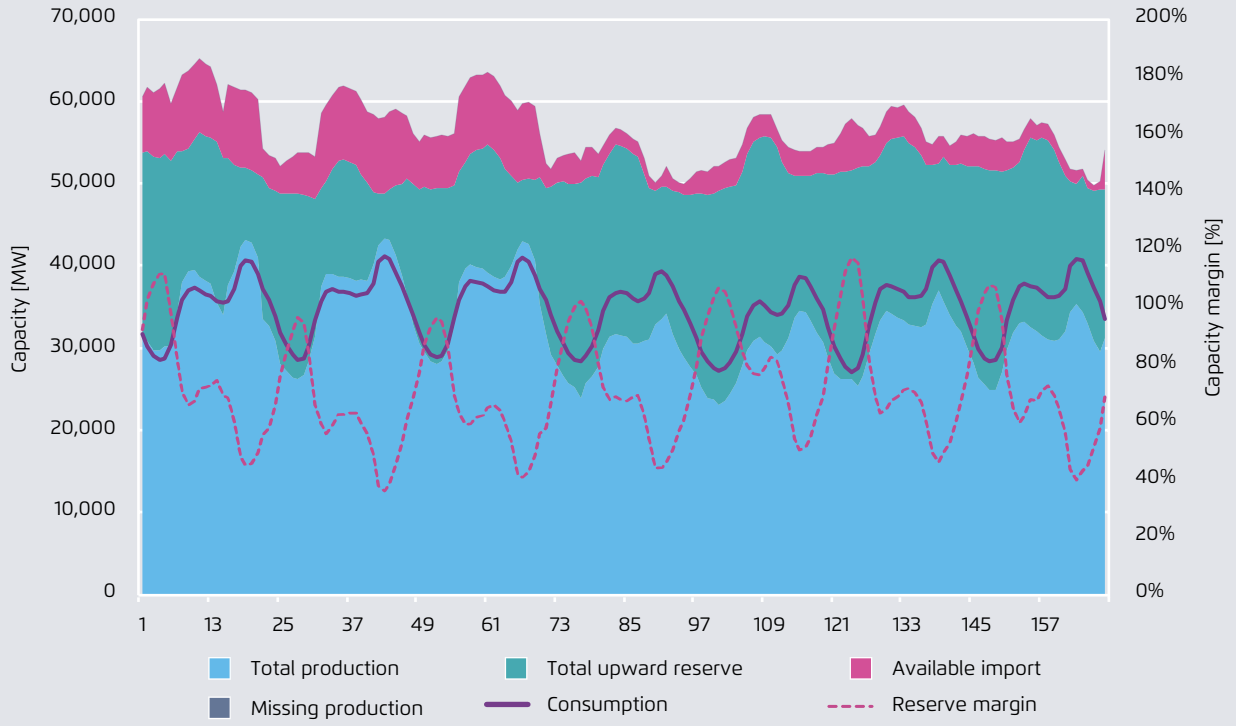
Security of supply: Sensitivity of varying weather conditions and interconnector capacities

We analyzed scenarios with average, high and low generation from hydro, wind and PV (based on historical data) and a scenario with higher and lower than expected interconnector deployment.

In most weather-related sensitivity cases the number of start-ups increases, with the exception of the low hydro and reference PV/wind case, where start-

Reserve margin in the SEE region for the critical week in winter in 2030 in MW

Figure ES 6



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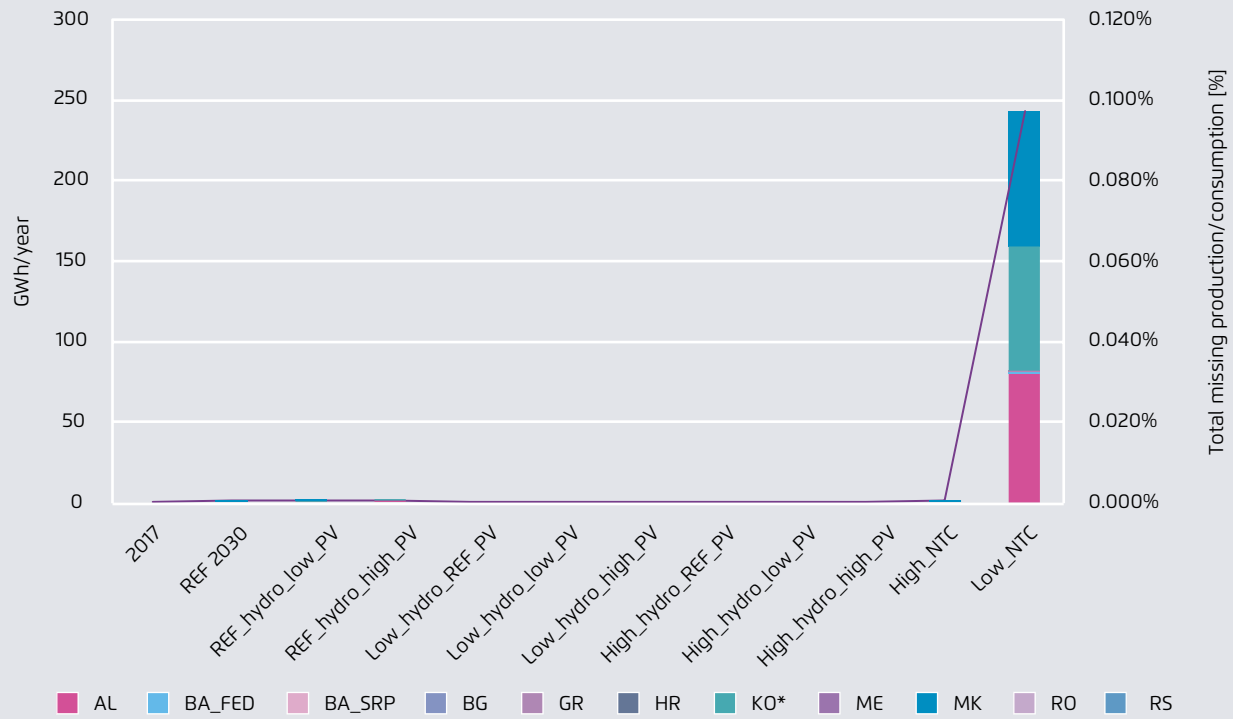
ups of conventional power plants decrease. The main reason for this rather unexpected result is that PV and wind generation patterns and hydro availability (dry or wet year) are not correlated. Consequently, it may happen that in a dry year with low hydro availability and less volatility, more permanent wind conditions will prevail, which would offset overall system volatility. Hence, low correlation among various RES generation sources is an important enabler of vRES system integration.

The case with a 20% lower value of NTCs yielded more start-ups because countries would have to balance their systems by relying more on power plants within their borders given their limited access to import. The higher NTC scenario (20% higher NTCs than in the reference case) does not decrease the level of start-ups. This means that the planned NTC development in the region (in line with ENTSO-E's TYNDP) would reach a satisfactory level in the 2030 reference case.

Figure ES 7 shows the non-satisfied demand for all scenarios. Non-satisfied demand amounts to only a few gigawatt hours in the reference case and remains the same in most sensitivity cases. As the figure illustrates, the most important impact on non-satisfied demand arises from altered NTC levels. With 20% higher NTCs, annual missing production drops to zero, while more than 240 GWh/year demand is left unsatisfied (corresponding to only 0.1% of regional power demand), with 20% lower NTCs available. Three countries are primarily affected: Albania, Kosovo* and North Macedonia. This emphasizes the key role of interconnection capacity for security of supply.

Missing production values (non-satisfied demand) for the sensitivity scenarios in GWh/year Figure ES 7



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Even though there is enough spare capacity on the regional level, the lack of interconnectors in the 20% lower NTC sensitivity case hinders the full use of power plants in neighbouring countries, which, in turn, leads to unserved power demand in Albania, Kosovo and North Macedonia. This underlines the importance of interconnection levels in the SEE region. The planned infrastructure development can help countries maintain the flexibility and security of supply of the regional system, though the lack of interconnectors can leave some countries vulnerable during certain critical hours.

Conclusions: Pathways for robust RES deployment and security of supply in SEE

With roughly half of the installed hard coal and lignite generation capacity in SEE requiring modernization or replacement in the next decade, we now have an excellent opportunity to introduce the 50 to 55% share of RES in the region required by the EU's 2030 targets for climate and energy. Indeed, the 2030 SEE scenario assessed in this report finds that RES-E shares of 50% are realistic in terms of system flexibility, RES integration and security of supply. The scenario projects that the level of available upward reserve capacities will decrease relative to 2017 because of higher vRES penetration. The available upward reserve capacity margin will still be above 40% in the region during most hours, and only for a few hours per year (under 15 hours) will it fall to 35%. This indicates that a higher level of cross-border capacities within the SEE region would help maintain the system adequacy throughout all hours of the year. Moreover, the available downward reserve capacities will increase thanks to vRES potential to provide such services.

The results also indicate that the projected infrastructure developments of the analysed Decarbonisation Scenario - characterised by major reductions of coal- and lignite-based generation and steadily increasing RES generation – will meet the growing demand of the region, achieving a nearly balanced net import position at the regional level by 2030. As coal and lignite production decreases, vRES production and gas-based generation will take their place (though the increase of gas-based generation will be confined to just a few countries in the region). Note that the annual average utilization of gas plants in the region is not projected to exceed 45% in 2030 for our sensitivity cases. Thus, the business model for conventional power plant operators is all about flexibility, not simply about the sale of kilowatt hours. If lignite utilization falls below 65%, lignite plants will have a hard time earning sufficient revenue from the power markets.

The critical week assessment shows that the reserve margin in the SEE system will stay above a healthy 35% even during critical hours of the assessed weeks, which presents a satisfying level for the region ensuring security of supply. At the same time, in most hours of the year the region maintains an even higher level of reserves: At over 100% of regional consumption in many hours, the SEE region will be able to provide flexibility services to neighbouring electricity systems such as those of Hungary and Slovakia, where flexible units are likely to be scarcer. The analysis has shown that the most critical season in SEE is autumn, where availability of hydro resources is limited due to lower water reservoir levels. This shows the need to diversify flexibility options through geography as well as technology.

The number of plant start-ups will also stay in the manageable range – below 40 start-ups a year for any conventional unit. By 2030, the system will have many dedicated flexible gas units; several coal and lignite plants will also contribute to the provision of system flexibility. Variable RES curtailment will remain low because hydro-based generation and the contribution of fossil-based generation to system flexibility will help avoid zero marginal cost vRES curtailment in 2030. This underlines the economic potential of efficient RES integration in the region.

The sensitivity assessment shows that interconnections and market integration are key factors for maximizing the security of supply and providing the required flexibility for vRES deployment in the SEE region. A limited level of non-satisfied demand will occur in Albania, Kosovo* and North Macedonia due to increased network limitations. This underlines the importance of continuing the implementation of cross-border infrastructure developments. More importantly, market integration must be deepened among SEE countries in order to utilize available cross-border capacities efficiently. This not only brings security of supply benefits; it also has an economic rationale, for it gives the region greater access to the electricity markets of neighbouring countries in Central and Eastern Europe. Most importantly, SEE can provide flexibility services to these countries in seasons/years with higher levels of hydro availability.

In summary, a diverse mix of flexible generation technologies in SEE (hydro technologies, flexible biomass, natural gas and storage) can facilitate the integration of vRES – especially wind and PV. In particular, reduced flexibility needs and increased system reliability can be achieved by integrating countries and regions with fundamentally different weather regimes. **An interconnected European power system would be highly beneficial for vRES integration.** Indeed, regional cooperation, stronger power systems and market integration will help minimize power system costs for consumers while maximizing supply security.

Introduction

With the recently adopted EU 2030 targets for climate and energy, European power systems are about to embark on a major transition. By 2030 an average of 55% of electricity in Europe's power grids must come from renewable energy sources. Now is therefore an auspicious moment for advancing a clean-energy transition in South East Europe (SEE).

Countries throughout SEE have high shares of electricity generated by an aging fleet of coal-fired power plants. Some of the youngest coal plants in the Western Balkans were built in 1988, before the break-up of Yugoslavia. Within the next decade, utility companies and governments will have to decide whether to modernize or replace roughly 50% of the region's existing coal and lignite generation capacity. Indeed, the recent SEERMAP project[6] has demonstrated that deployment of renewable capacity in the EU SEE and Western Balkans[7] is not only feasible but also has several advantages over fossil fuel-based investment.

Solar photovoltaics (PV) and wind power – driven by significant cost reductions – will almost certainly contribute to more than half of the RES-E share in Europe in 2030. As wind and solar depend on weather, future power systems will be characterized by fundamentally different generation patterns from those observed today, significantly increasing the need for flexibility in the non-intermittent part of the power system. In meeting the flexibility challenge, regional cooperation and cross-border power system integration offer important ways forward.

This study takes a deeper look into the future of regional market integration for power systems with high shares of wind and solar in SEE: what kinds of flexibility requirements arise from the projected growth of these two technologies? And to what extent can further power market integration within SEE and beyond help meet that challenge?
This study builds on the SEERMAP project, which analyzes the region's energy sector through long-term scenarios. We focus on the project's "decarbonization scenario", which assumes 93% decarbonization in the region's power sector by 2050 (in line with EU goals) and a RES-E share of 50% in 2030 in the SEE region. The applied REKK's European Electricity Market Model (EPMM) tool captures the interplay between supply, demand and storage over an entire calendar year, i.e. 8760 hours. The scenario for the energy system in 2030 addresses the following questions:

- → Will SEE power demand be met in all hours in 2030?
- → Will the SEE power system have a sufficient reserve margin to guarantee the security of supply in critical situations?
- → What will be the critical/vulnerable weeks or days in the system?
- → Will the system also be robust during extreme weather patterns? (e.g. in years of low precipitation or with lower number of hours of wind).

Here are some of the key characteristics of the model (its individual features are described in later sections):

- → All hours of a selected year are modelled;
- → Its optimization takes places on a (rolling) weekly basis, with the objective being to minimize system costs.
- → The hours during the week are interconnected: the operation of a power plant in a given hour has

6 See http://rekk.hu/analysis-details/238/south_east_europe_electricity_roadmap_-_seermap

7 In SEE, the EU member states are Bulgaria, Croatia, Greece and Romania. The Western Balkans countries are Albania, Bosnia and Herzegovina, Kosovo, North Macedonia, Montenegro and Serbia.

impact on its availability for the next hours. A yearly modelling sequence consists of 52 weekly optimization steps, where the weeks are also connected: information on the last hour of operation for the production units in the modelled week is passed on to the next week.

→ Power plants in the model are represented through higher granularity (e.g. start-up costs, start-up time and minimum utilization rates) than in a typical power generation technology modelling characterisation (e.g. fuel type, fuel efficiency, marginal cost);

→ EPMM covers the entire ENTSO-E power system, including EU member states and the contracting parties of the Energy Community.

The modelling approach

The EPMM is a unit commitment and economic dispatch model, which during the optimization process satisfies electricity demand in the modelled countries at minimum system costs while considering the different types of costs and capacity constraints of the available power plants and cross-border transmission capacities.

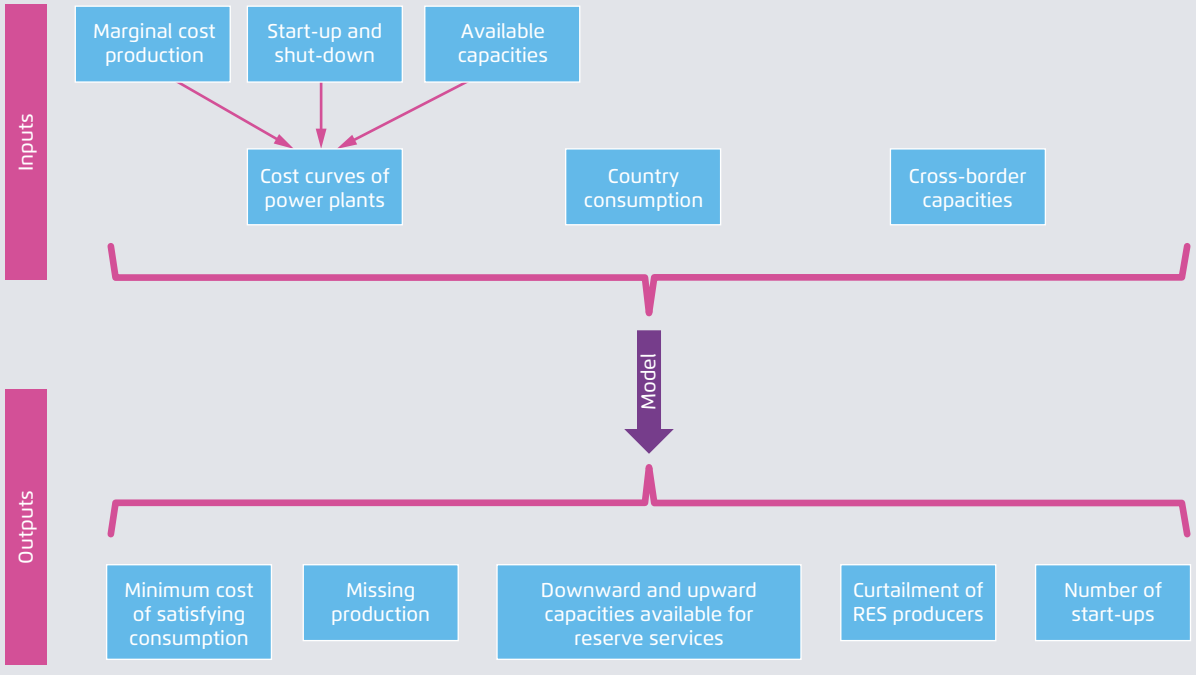
The model minimizes the production costs for satisfying demand. These costs include the start-up and shut-down costs of the power plants, the costs of production (mostly fuel and CO_2 costs) and the costs that occur in case of RES curtailment.

The model simultaneously optimizes all 168 hours of a week and determines the hours of the week in which power plants operate and their production levels. The model is executed for all weeks and hours (8760) of the year. To increase the robustness of the results, the model starts the weekly optimization on Wednesdays and finishes on Tuesdays, to avoid that the fastest ramp-up period (Monday morning) would be the starting position of the optimisation. EPMM endogenously models 41 electricity markets in 38 countries.[8]

The main inputs and outputs of the model are summarized in Figure 1.

8 In the cases of Bosnia and Herzegovina, Denmark and the Ukraine, two markets/price zones are distinguished per country; otherwise one market/price zone per country is assumed.

Main inputs and outputs of the EPMM model — Figure 1



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The results of the optimization show how electricity demand can be satisfied at a minimum cost while yielding the optimal generation mix and the required number of power plants start-ups in the modelled region. The potential for missing production and the available upward and downward capacities for reserve services are also important outputs of the model.

Supply side representation in the model

Power plants are represented at the unit/block level for each country and are divided into twelve technologies: biomass, hard coal- and lignite-based, geothermal, heavy and light fuel oil, hydro, wind, PV, nuclear, natural gas and tide/wave power plants.

All generation units have the following inputs: installed capacity, electrical efficiency and self-consumption. The short-run marginal costs of generation are calculated based on country- and technology-specific fuel prices, variable operational costs, taxes and CO_2 emission costs. Start-up costs are also included for dispatchable units (thermal, nuclear, storage hydropower and pumped storage). The start-up assumptions are summarized in Table 1.

Renewable generation – apart from biomass and storage hydropower, is included exogenously assuming zero marginal cost. Generation patterns are based on European weather data from 2006–2011 for PV and wind generation and 2008–2017 for hydro. These renewable technologies are non-dispatchable but can be curtailed at given costs.

We distinguish between three categories of hydro generation: run of river, pumped storage and reservoir. The reservoir hydro units can flexibly produce electricity with a maximum aggregate production constraint for the entire week. This allows the model to capture the flexibility of hydro generation while placing a realistic limit on its overall contribution to weekly and yearly electricity generation.

Demand-side representation in the model

Power demand is an exogenous input to the hourly optimization of the power system. Hourly demand data is derived from actual data for 2015, which is adjusted in the scenarios proportionally based on the assumed growth of yearly consumption by 2030. Power demand is met by the available power plants

Start-up costs and constraints for dispatchable technologies. Table 1

	Unit	Nuclear	Lignite (>500MW)	Lignite (<500MW)	CCGT	Other steam turbine	Gas turbine	Small generation units	Coal (>500MW)	Coal (<500MW)
Minimum load	%	50	45	45	40	30	20	0	35	35
Start-up fuel requirements	MWh/MW	16.7	5.9	2.7	2.8	2.8	0.1	0.1	5.9	2.7
Start-up costs	€/MW	50	49	105	60	57	24	24	49	105
Start-up time	hours	8	6	4	2	1	1	1	6	4

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and the import capacities subject to minimisation of the cost to serve demand.

Transmission grid representation

In the EPMM model, each country represents one node, so network constraints inside the countries are not considered. Cross-border transmission capacities are represented by net transfer capacities (NTCs) values, which put an upper limit on cross-border electricity trading. Power exports and imports, therefore, may not exceed NTC values in any given hour. Imports and exports take place to minimize system costs and maximize security of supply.

Calibration of the model and input data

To ensure robust modelling results, the model was calibrated to the latest available data (2017). Table 2 illustrates the difference between the calibrated model results and actual data for 2017. The difference between the two data sets is well below 6% for the main production technologies. The only exception is gas units, where the difference is 23% due to the sensitivity of the assumed gas prices. These prices are not publicly available for many countries in the EU, which makes it difficult to calibrate natural gas-based production.

To ensure robust results, various weather regimes are included in the modelling that account for the variability of renewable energy resources. This required collaboration with the Vienna University of Technology (TU Wien), which provided information on RES production covering the whole ENTSO-E system, including the SEE region. Data on variable RES production (i.e. solar PV, wind and hydro) and on dispatchable RES are derived from TU Wien's Green-X model.[9] Historical weather data and projections for future installed capacities were used to generate RES generation patterns on an hourly basis.

More input data and assumptions for the EPMM model can be found in Appendix 1. The information includes details about power plant capacities, fuel prices and available NTC capacities for the modelled region.

9 For a recent study describing the GREEN-X model, see del Rio et al (2017): A techno-economic analysis of EU renewable electricity policy pathways in 2030, Energy Policy.

Modelled and actual production share by technology in the EU, 2017. Table 2

GWh	Total	Nuclear	Coal and lignite	Natural gas	Run-of-river, storage	Pumped storage	Wind	Bio-mass	HFO, LFO	PV	Other RES
Model	3 597 254	838 381	849 333	613 272	592 601	-5 223	386 419	177 953	12 894	117 391	14 233
Actual	3 680 400	808 100	798 300	757 300	576 700	n.a.	370 300	174 200	29 300	114 600	12 600
Difference, GWh	83 146	-30 281	-51 033	144 028	-15 901	5 223	-16 119	-3 753	16 406	-2 791	-1 633
Difference, %	2.3%	-3.6%	-6.0%	23.5%	-2.7%	n.a.	-4.2%	-2.1%	127.2%	-2.4%	-11.5%

REKK, ENTSO-E (2018)

The SEE power system in 2030

Though situations will vary significantly from country to country with regard to domestic resource availability (hydropower, solar irradiation, wind speed), renewables are expected to be "mainstream" by 2030 throughout Europe. The assessed decarbonization scenario assumes a 2030 RES-E share relative to gross consumption of 48%[10] in Europe and of 50% in SEE.

This section looks at this scenario in detail. We start by assessing the aggregated yearly results and then study potentially critical weeks with tight supply/demand situations. In this way, we measure both the average performance of the markets/power systems and the robustness of the system in critical situations. We conclude with a sensitivity analysis. Throughout this report, the term "SEE region" refers to the Western Balkan countries (Albania, Bosnia and Herzegovina, North Macedonia, Kosovo*, Montenegro and Serbia) and the EU countries Bulgaria, Croatia, Greece and Romania.[11]

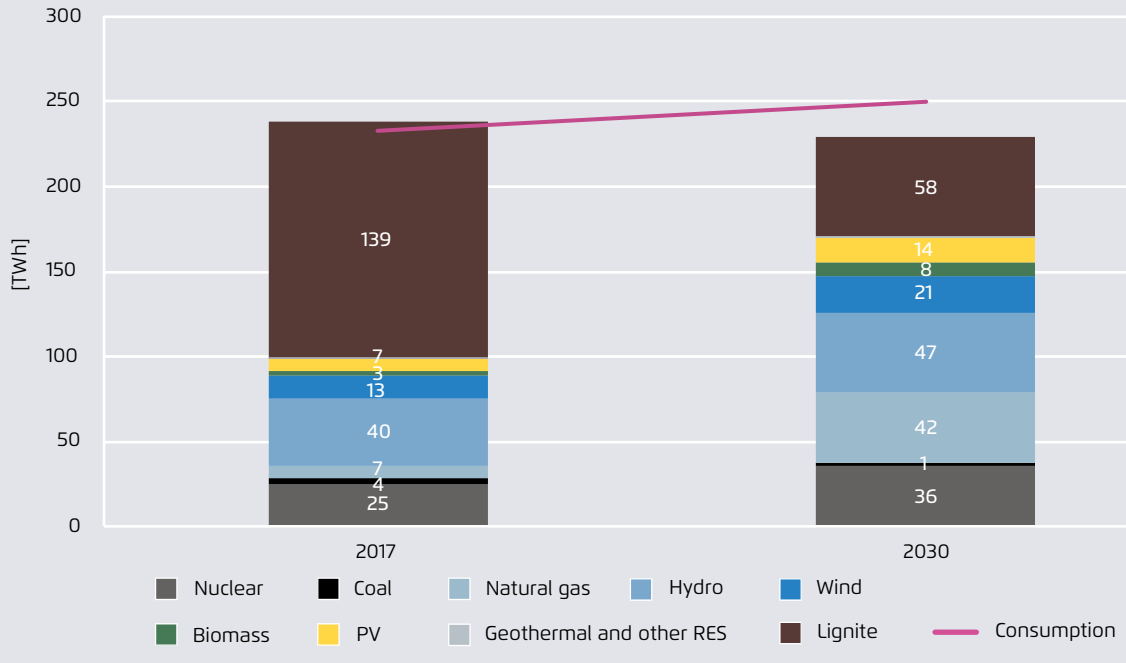
Yearly electricity mix in SEE

Figure 2 shows the annual power mix for the SEE region in 2017 and 2030.

10 See also Fraunhofer IWES (2015): The European Power System in 2030: Flexibility Challenges and Integration Benefits. An Analysis with a Focus on the Pentalateral Energy Forum Region. Analysis on behalf of Agora Energiewende.

11 *This designation is without prejudice to positions on status, and it is in line with UNSCR 1244 and the ICJ Opinion on the Kosovo declaration of independence.

Electricity generation mix of the SEE region, 2017 (actual data) and 2030 (decarbonization scenario) Figure 2



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The most important change for the region is the sharply falling share of coal- and lignite-based generation. Compared with 2017, less than half of the production from these fuels will remain in the system by 2030. The reduction will be compensated by an increase in RES generation of 20 TWh, in natural gas-based production (25 TWh) and in nuclear generation (11 TWh). The region will move from a net export to a net import position, but the yearly net import ratio will remain relatively small – 6.8%. The capacity mix changes significantly in the decarbonization scenario, with a shift away from fossil-based capacity towards renewable capacity. The changes are driven primarily by rising carbon prices in EU countries and decreasing renewable technology costs. Although the Western Balkan countries are assumed to have carbon prices only from 2030, in the scenario only 1500 MW new fossil based generation is installed in the SEE region, due to the assumed economic environment: increasing carbon prices elsewhere, rising coal and natural gas prices and deteriorating utilization rates of fossil generation. Over the long-term, lignite- and coal-based generation will not be able to reach the required utilization levels needed to cover the increasing investment costs and meet the higher emission standards set by new European legislation.
On a country-level, Bosnia and Herzegovina, Bulgaria, Kosovo*, North Macedonia, Montenegro and Serbia will become net importers of electricity due to a strong decrease in coal- and lignite-based generation and a smaller increase in RES generation. Meanwhile, the net export positions of Bulgaria, Greece and Romania will increase because the decreasing coal- and lignite-based generation will be more than compensated by natural gas and RES-based generation.

Impact of RES on conventional power plants: Start-ups and utilization rates

Both in Europe and in the SEE region, the 2030 scenario shows a more flexible utilization of power plants based on an increase in the number of start-ups per unit. This is a consequence of a lower utilization of conventional power plants due to the increased generation of variable RES and the deteriorating economic performance of coal and lignite plants. Climbing fossil-fuel costs, carbon prices and increasing investment costs place fossil-fuel-fired plants at the end of the merit order curve, resulting in a lower number of operation hours. This impact is further amplified by the growing production of zero-cost PV and wind generation, which on account of the "merit order effect" will supplant more and more fossil fuel plants from the pool of generators. Even though the number of start-ups will increase, by 2030 the total start-up costs as a share of variable generation costs will only amount to 1% in both the EU and in SEE (see Table 3).

Fossil-based dispatchable power plants and cost of start-ups in 2017 and 2030. Table 3

		Number of units	Number of start-ups	Number of start-ups per unit	Total variable cost, m€	Total start-up cost, m€	Start-up cost/total cost
Europe	**2017**	2202	14365	6.5	70636	721	1.02%
	2030	1522	13245	8.7	77664	906	1.17%
SEE	**2017**	167	441	2.6	4443	24	0.54%
	2030	89	798	9.0	5824	60	1.04%

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At the same time, the utilization rates of the different types of power plants will have changed significantly by 2030, with the utilization of natural gas plants climbing to 40% from 7.5% in 2017 and the utilization of hard coal-fired plants growing from 20% to 34% in the SEE region. The utilization of lignite-fuelled plants is projected to fall in Europe and in the SEE region, down from 81% to around 68%, due to deteriorating economic performance and reduced operating hours (see Table 4).

To gain a deeper understanding of how electricity markets function in the modelled years for SEE, we analyzed the relationship between utilization rates and the number of start-ups in detail. Figure 3 shows the 2017 and 2030 yearly average utilization rates of non-RES power plants on a unit level.

The most important change between 2017 and 2030 is that more and more power plants will be operated in "peak load" mode: natural gas power plants with low yearly average utilization rates and a high number of start-ups (up to 35 times/year). For comparison, the highest number of start-ups for a given unit in 2017 was less than 20 in SEE. By 2030 more than half of the gas-fired units will actively provide flexibility services. The utilization structure of coal-, lignite- and HFO-LFO-fuelled plants will change similarly by 2030 – increasingly operating in "flexibility services mode". In the future electricity system, they will provide more system balancing and flexibility services and receive more of their income from short-term power markets instead from baseload energy sold on the futures and day-ahead markets.

Transmission grid constraints and RES curtailment

The model has the option of curtailing vRES producers (variable RES: PV and wind generators) if needed for system stability when interconnectors are fully utilized and surplus generation cannot be exported. In keeping with European legislation, curtailed RES producers are compensated for their curtailment at the level of their forgone revenue.[12] The model does not need to utilize this option often, as just a few EU countries – Spain, Portugal and Italy – hit curtailment levels in certain hours. In Europe, curtailment will not exceed 500 GWh a year in 2030,[13] and it will remain zero in the SEE region. The alternative of non-compensation of RES curtailment was also tested, and confirmed robustness of the results. In

12 See Art. 12 of the recently adopted Electricity Market Regulation.

13 This corresponds to 0.014% of European power demand.

Utilization rates for different power plant technologies, 2017 and 2030. Table 4

		SEE			Europe		
		2017	2030	Change	2017	2030	Change
Utilization rate	Nuclear	84.8%	85.2%	**0.3%**	79.2%	81.0%	**1.7%**
	Natural gas	7.5%	39.9%	**32.4%**	27.0%	31.2%	**4.1%**
	Hard coal	20.2%	33.8%	**13.5%**	36.2%	46.1%	**9.9%**
	Lignite	77.6%	63.3%	**-14.4%**	80.4%	68.4%	**-12.0%**
	HFO	0.1%	1.3%	**1.2%**	4.5%	0.9%	**-3.7%**
	LFO	0.0%	0.0%	**0.0%**	7.3%	0.5%	**-6.8%**

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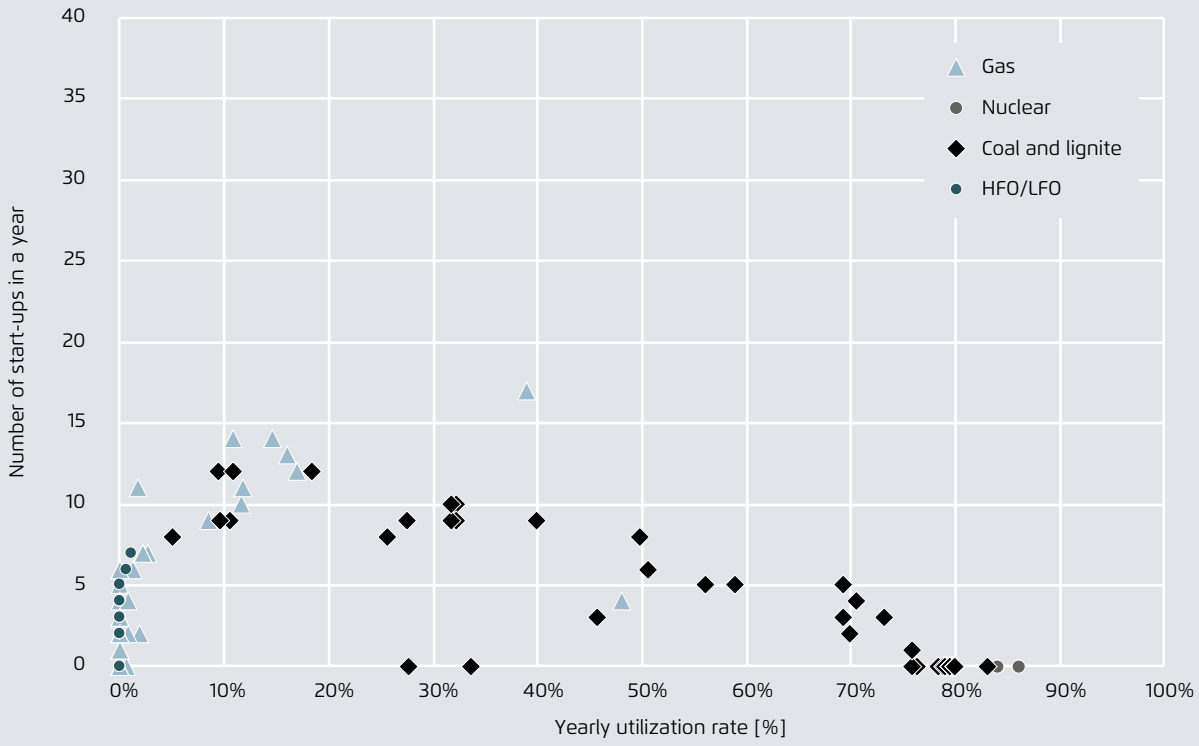
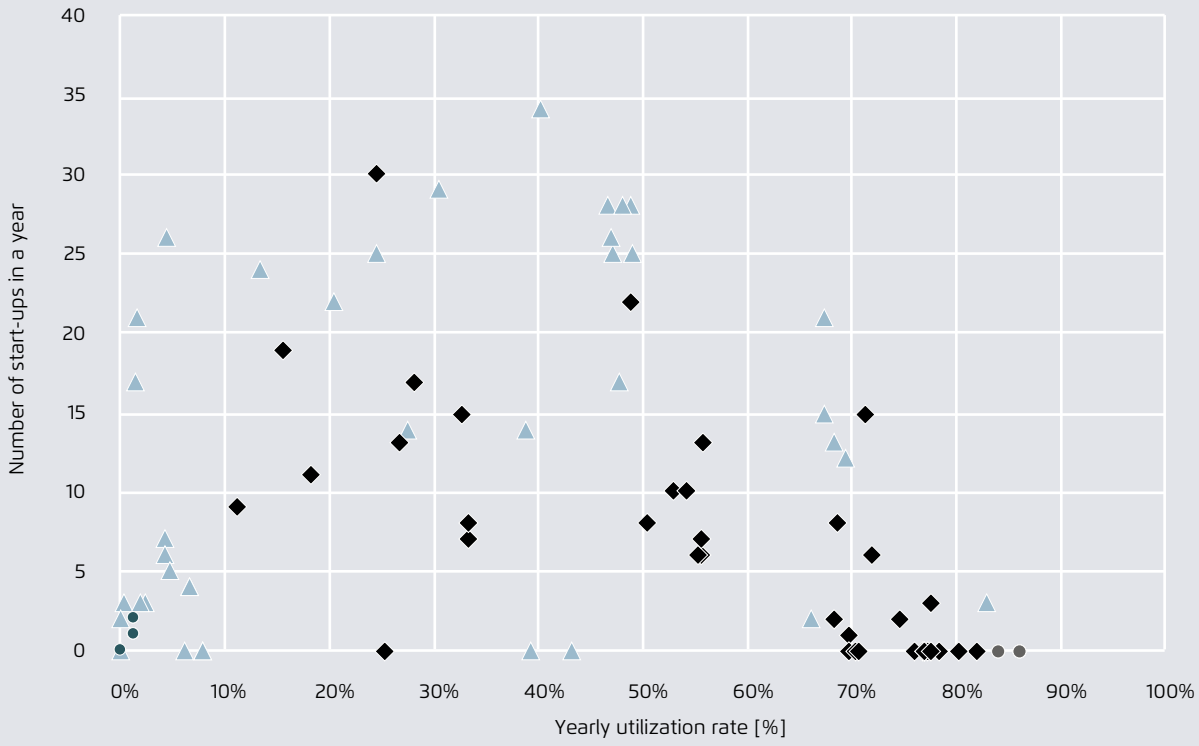
Yearly average utilization rates and number of start-ups (per year) on a unit level in the SEE region in 2017 (above) and 2030 (below)

Figure 3





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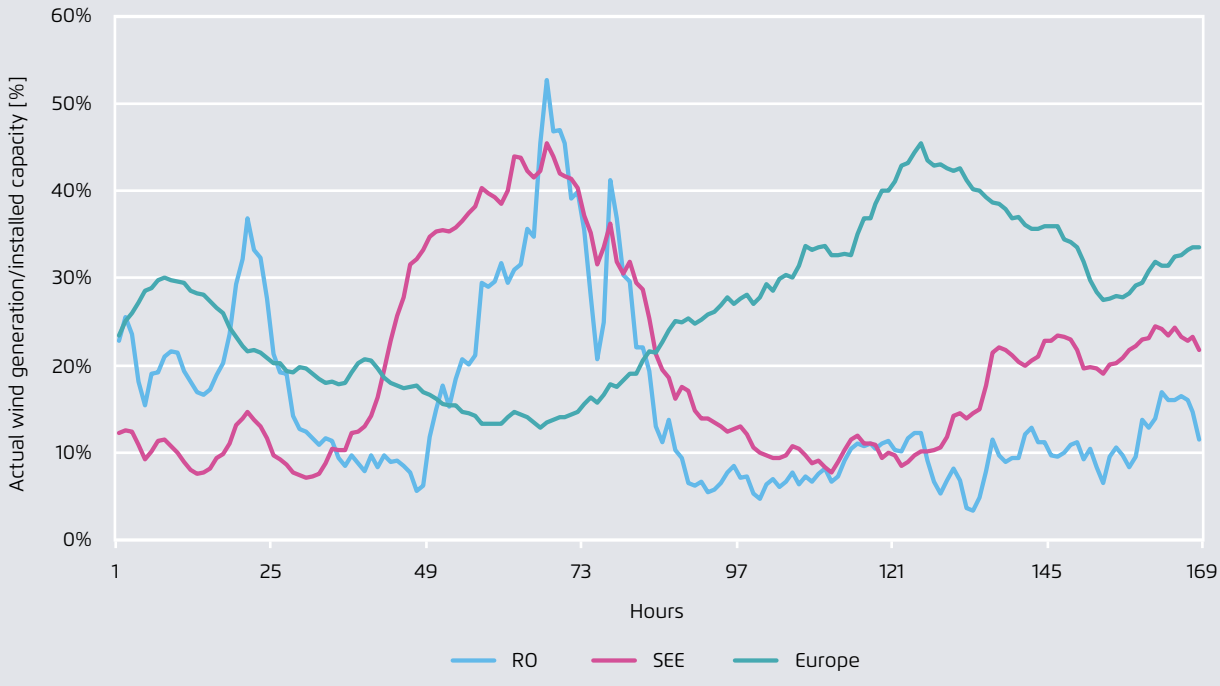
case of non-compensation curtailment levels increase slightly due to market-based decisions of RES producers. However, it still represents a minor level of 500 GWh in Europe. The main reason for this low level of vRES curtailment is the availability of flexible hydro resources in the region that can satisfy the flexibility need in the power system according to the model results, the availability of interconnectors, the flexibility potential offered by imports and exports and the low correlation between RES feed-in across borders.

PV generation is highly correlated within the region, with correlation coefficients ranging from 87% to 100% between the countries, depending on their proximity. This is indeed to be expected, as the difference is mainly caused by the sun's daily periodicity. However, and importantly for easing vRES system integration, we observed a very different pattern in the correlation of wind generation. Even within the SEE region, wind speeds show weak correlations, ranging from 11% to 46%. These fairly low correlations suggest that wind generation would not peak at the same time within the region; rather, it would be dispersed over time.[14] It also suggests that the region would follow a different wind generation pattern from northern European countries, which

14 This confirms earlier research testing the correlation of wind power feed-in between the countries of the Pentalateral Energy Forum (Austrian, Belgium, France, Germany, Luxembourg, the Netherlands, Switzerland) where correlation coefficients ranged from 24% (Austria and Belgium) to 66% (Luxembourg and Belgium). For more details, see Fraunhofer IWES (2015): The European Power System in 2030: Flexibility Challenges and Integration Benefits. An Analysis with a Focus on the Pentalateral Energy Forum Region. Analysis on behalf of Agora Energiewende.

Time series of onshore wind power generation in a simulation for the first week of 2030 at different levels of aggregation

Figure 4



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means that wind production would not peak at the same time in the wider European region.[15]

As can be seen in Figure 4, periods of little or no wind power in 2030 will be less frequent and total output changes will become softer and slower. These effects will help lower flexibility requirements in the region.

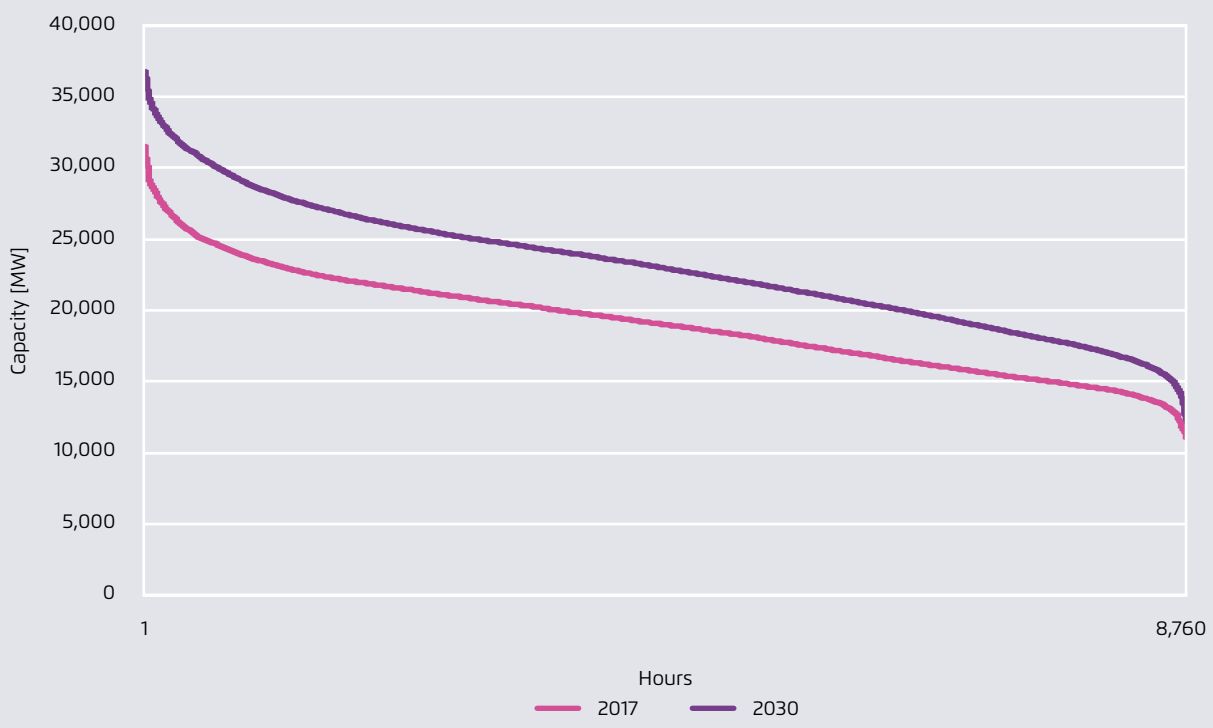
15 For example, Grams C. et. al. (2017) find that balancing future wind capacity across regions – deploying slightly more capacity in the Balkans than at the North Sea, say – would eliminate most wind production output variations, better maintain average generation and increase fleet-wide minimum output. See Grams et al (2017): Balancing Europe's wind-power output through spatial deployment informed by weather regimes. Nature Climate Change.

Security of supply: Available reserve capacities

a) Downward and upward reserve capacities

One of the main features of the EPMM model is its ability to calculate the remaining available upward and downward reserve capacities in all hours for all countries individually. These reserve capacities can step in if demand unexpectedly rises in real-time or if generation unexpectedly drops in real-time (e.g. due to a power plant outage or lower than forecasted RES generation). Figure 5 shows the total available downward reserve capacity for all hours of the year (in descending order) in the SEE region. There is no single hour in 2017 or 2030 when a shortage of downward reserve could be identified. Moreover, the situation improves in 2030 even more, mainly due to the deployment of RES and natural gas plants, which can both provide downward regulation. The

Total available upward reserve in the SEE region, in all hours of 2017 and 2030 Figure 5



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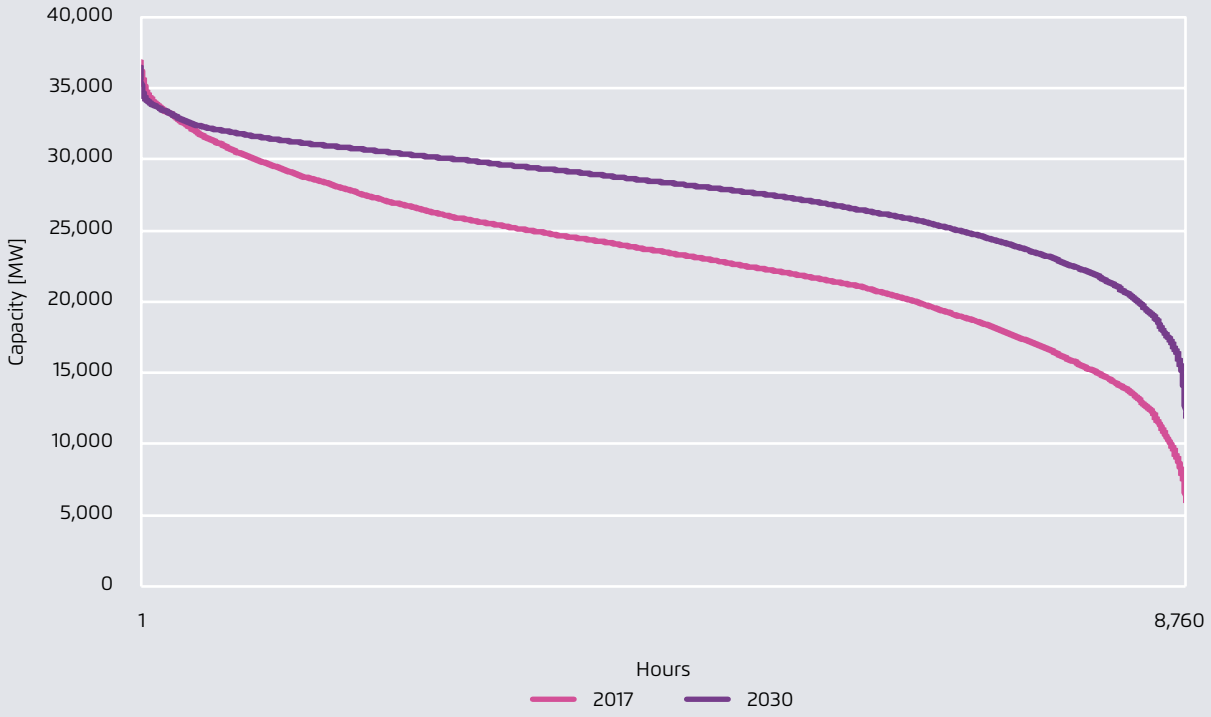
Total available upward reserve in the SEE region, in all hours of 2017 and 2030 Figure 6



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minimum downward reserve capacity is projected to be ca. 11 GW in 2030 – this corresponds to 27% of the regional peak load.

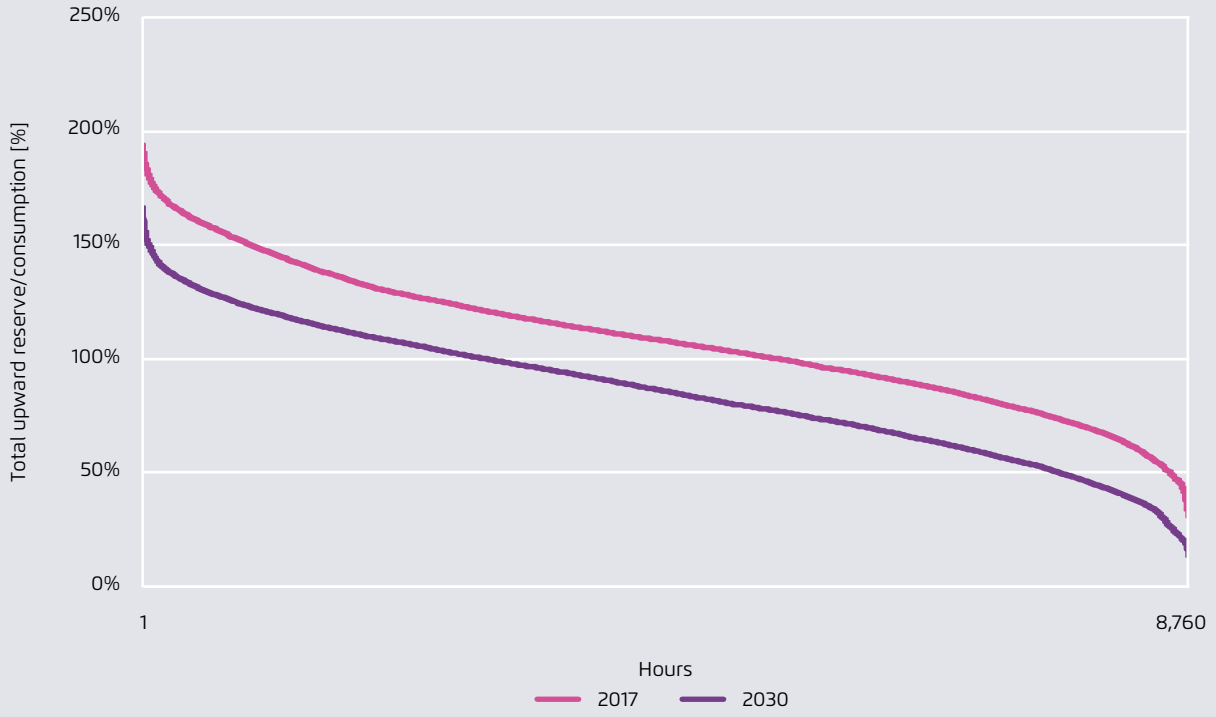
For upward reserve capacities, somewhat different patterns can be observed. The amount of available upward reserve capacities in 2030 is lower than in 2017. This is the result of a drop in the number of dispatchable units fuelled mainly by coal and lignite. Still, the upward reserve capacities are not expected to fall below 5 GW in 2030, which corresponds to 12% of the regional peak load. For the vast majority of hours in 2030, upward reserve capacities do not drop below 20 GW (see Figure 6).

To assess whether this drop is critical, we compared the total available upward reserve capacity with total consumption in SEE for all hours of the modelled years. There are only 5 hours in which available capacity drops below 15% of consumption, and it never falls below 12%. General evaluation criteria indicate that a minimum of 5–10% of consumption is needed for upward reserve capacity to guarantee security of supply. By these lights, the SEE region will have a sufficient level of supply security in 2030 (see Figure 7).

b) Missing production

Another widely used evaluation criterion for security of supply is the number of hours with missing production. There was no such modelled hour in the region in 2017, while the model predicts low levels of missing production in 2030. Table 5 indicates the number of hours in which capacities are insufficient. The scenario shows hours with missing production in Albania, Kosovo* and North Macedonia. However, the missing production levels occur in one or two hours of the year, which indicate very low

Total available upward reserve in the SEE region by percentage of consumption, 2017 and 2030 Figure 7



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Number of hours with missing production in the SEE countries. Table 5

	Number of hours with missing production	
	2017	2030
AL	0	1
BA_FED	0	0
BA_SRP	0	0
BG	0	0
GR	0	0
HR	0	0
KO*	0	2
ME	0	0
MK	0	1
RO	0	0
RS	0	0

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load-shedding requirements. The typical security of supply standards in the EU range from three to six hours of loss-of-load expectation.

The results on missing production levels and low cross-border correlation of vRES feed-in emphasize the importance of regional cooperation and the availability of sufficient interconnection capacity between countries. As can be seen in the sensitivity analysis later in the report, increasing interconnection levels between the countries (represented by increasing NTC values) can eliminate missing production hours entirely, because countries with this problem can rely on imported electricity from neighbouring power systems. Though the sensitivity case with decreasing interconnection capacities still shows missing production in the system, it remains a very low fraction of the total.

Security of supply: Assessment of critical weeks

In this section we discuss the security of supply situation in weeks with high electricity demand. We first select and define the critical weeks and then elaborate on the results from the modelling.

Definition of critical weeks

For each season, we select one unique critical week, for a total of four critical weeks in all. All assessed weeks start on a Wednesday and finish on a Tuesday. We selected the critical weeks using the following method:

1. First we calculated *hourly remaining capacity* for all hours in the season. Remaining capacity is the sum of *spinning and non-spinning* reserve capacity and *non-utilized import capacity*.
2. Then we calculated the average of hourly remaining capacities to get the *average weekly remaining capacity of 52 weeks*.
3. The week characterized by the lowest average weekly remaining capacity in every season is defined as a *critical* week.

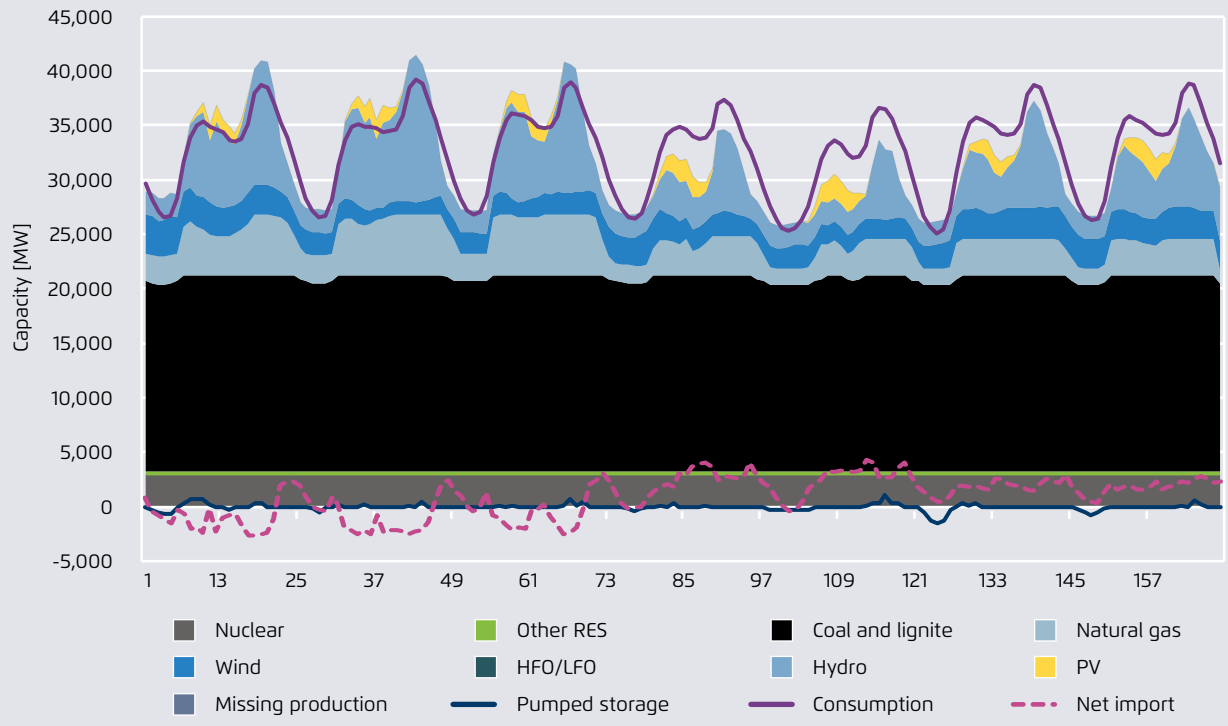
The critical week assessment elaborates two main outputs: the generation mix and the remaining reserve margin of the SEE region in the years 2017 and 2030. The critical weeks are identified and presented for each season.

Winter season results

The model runs for the **2017 critical winter week** yield the following findings:

Lignite and hard coal provided some 16GW for nearly every hour of the critical week. Nuclear pro-

Electricity generation and demand in the SEE region for the critical winter week in 2017 in MW — Figure 8



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Note: The week starts on Wednesday, 0:00 and ends on Tuesday 24:00.

vided some 4 GW to the mix. PV and wind, despite growing steadily, amounted to only 2-3 GW in the SEE. The main sources of flexibility for meeting electricity demand in the critical week were (see Figure 8):

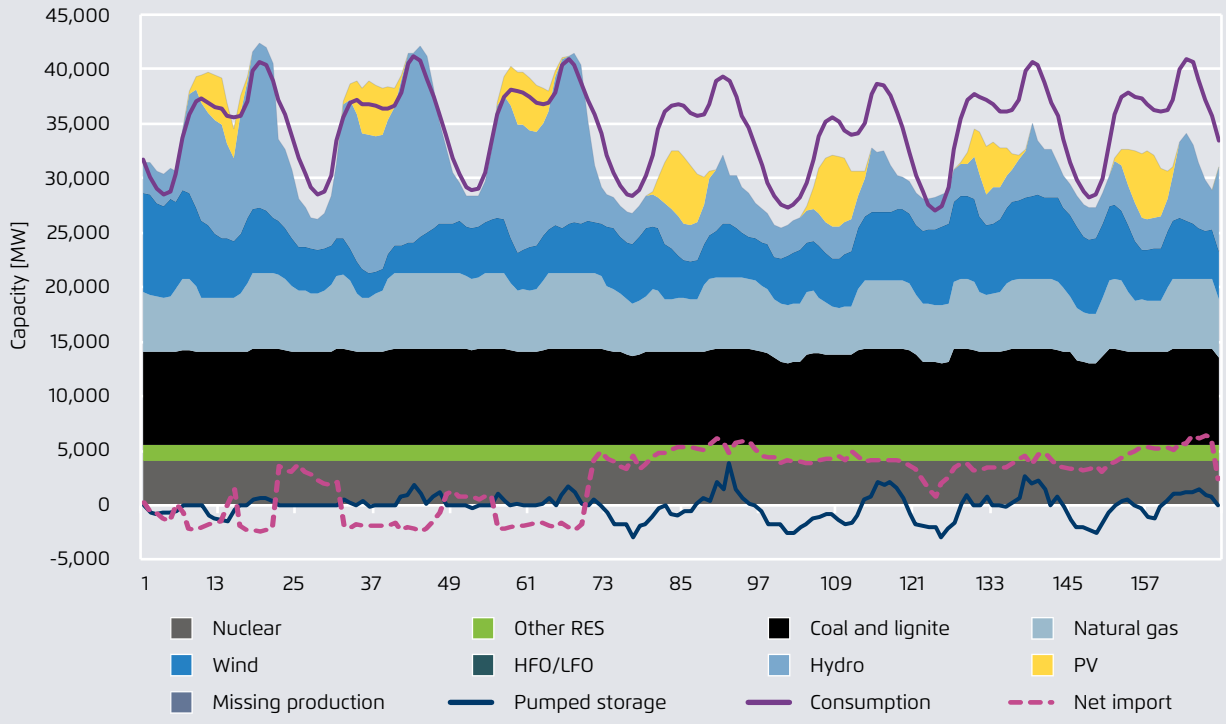
→ hydropower (storage, reservoir and pumped storage);
→ natural gas-fired power plants;
→ net import capacities.

The largest source of flexibility was hydropower, which offers a cheap and flexible option for power generation. The second largest contribution came from natural gas-based power generation, providing up to 5 GW production in any given hour. The use of gas-fired generation was more prominent on weekdays, however. This is because net imports served as a flexibility option predominantly on the weekends[16], when consumption levels are low and lower power prices kept gas-fired units from entering the power market. The region was a net importer mainly on the weekends, when import was more readily available; hydropower was reserved for the more volatile and high-demand periods on weekdays. Interestingly, coal- and lignite-fired power plant provided flexibility only rarely. Although technically feasible, the flexibility they provide is expensive given their ramp-up times and depreciation costs.

The results for the **2030 critical winter week** show a strong drop in lignite-based production when compared with 2017. Natural gas-based electricity generation patterns change from peak-load following to steadier generation because wind and PV output re-

16 The Monday-to-Wednesday effect can shift to a Wednesday-to-Friday effect if the model week starts Monday instead of Wednesday.

Electricity generation and demand in the SEE region for the critical winter week in 2030 in MW — Figure 9



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Note: The week starts on Wednesday, 0:00 and ends on Tuesday 24:00.

mains fairly low. (Wind and PV generation levels are still nearly double compared to 2017, however.) Consumption peaks are mostly managed by increased hydro utilization and increased net imports, whose greater potential derives from increasing NTC levels. In the first half of the week, net imports serve as "gap-fillers" while in the second half of the week they are utilized on a more constant basis (see Figure 9).

Figure 9 and Figure 10 show the reserve margins in the winter periods for 2017 and 2030. The reserve dipped below 100% in the peak hours for the SEE region in 2017, with reserves available for 60–80% of total consumption in peak hours – a very healthy margin. In off-peak periods, the reserve margin is above 100%, even reaching 140%. Only a small share of reserves (~5%) comes from imports[17]; the majority is based on domestic production. Overall, reserve margins are healthy, which is why there is no missing power production (Figure 10).

In 2030, the picture changes slightly: the reserve margin only occasionally reaches 100% and is considerably lower than in 2017, while in peak hours it is still 40–60%, which represents a sufficient level of reserves. Due to the increased use of renewables and intermittent generation, production is more volatile than in 2017, which means that the need for reserves is more pronounced in some hours. The higher volatility in production is indicated by the steeper "ramp-ups" and "ramp-downs" of the orange area in the figures (see Figure 11). Nonetheless, all electricity demand can be met in the region (unserved energy=0 GWh).

17 Interconnector utilization in the region ranges from 20 to 90%, indicating that some directions are constrained while others are not in the same hour. Simple averages or ranges would not precisely describe the level of constraints that occur in the critical week.

Reserve margin in the SEE region for the critical winter week in 2017, MW — Figure 10

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Note: The week starts on Wednesday, 0:00 and ends on Tuesday 24:00.

Reserve margin in the SEE region for the critical winter week in 2030, MW

Figure 11

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Note: The week starts on Wednesday, 0:00 and ends on Tuesday 24:00.

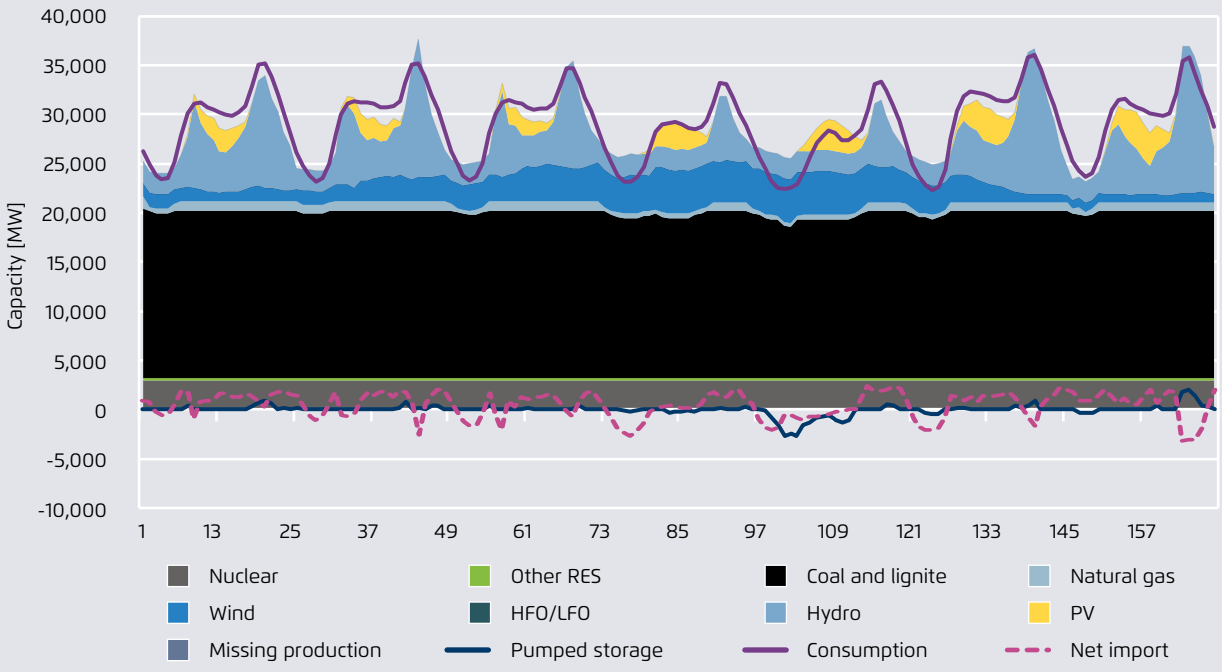
Spring season results

A major difference between the winter and spring critical weeks is the reduced need for natural gas-based generation. This is due to the higher availability of wind power in the spring. In 2017, spring wind- and solar-based generation was considerable in SEE (totalling some 8 GW – see Figure 12). Hydropower performed the majority of load-following while gas dropped out of the mix for economic reasons.

For 2030, lignite- and hard coal-based generation is replaced by gas-fired units (due to changing economics favouring gas plants over coal plants). In spring, net imports of the SEE region serve as a flexibility option providing up to 5–6 GW for some hours. Compared with the spring of 2017, gas plays a more important role, replacing the gap left by the decline of coal and lignite production that cannot be met by growing renewable generation sources. Wind and PV can provide up to 13 GW in the spring of 2030 in the SEE region (see Figure 13) because this week is characterized by abundant wind generation from Thursday to Saturday. Monday and Tuesday are different: wind energy generation halts, so imports must assume a considerable share of the demand.

Reserve margins in the spring of 2017 were usually above 100% and 70–80% only during high peak hours. This represents a very healthy ratio for the region and an asset for the Western Balkans, which can provide available reserve capacity to neighbouring EU member states (e.g. Hungary, Slovenia) if sufficient transfer capacity is available. Around half of the upward reserve was kept in non-spinning capacities (see Figure 14).

Electricity generation and demand in the SEE region for the critical spring week in 2017, MW Figure 12



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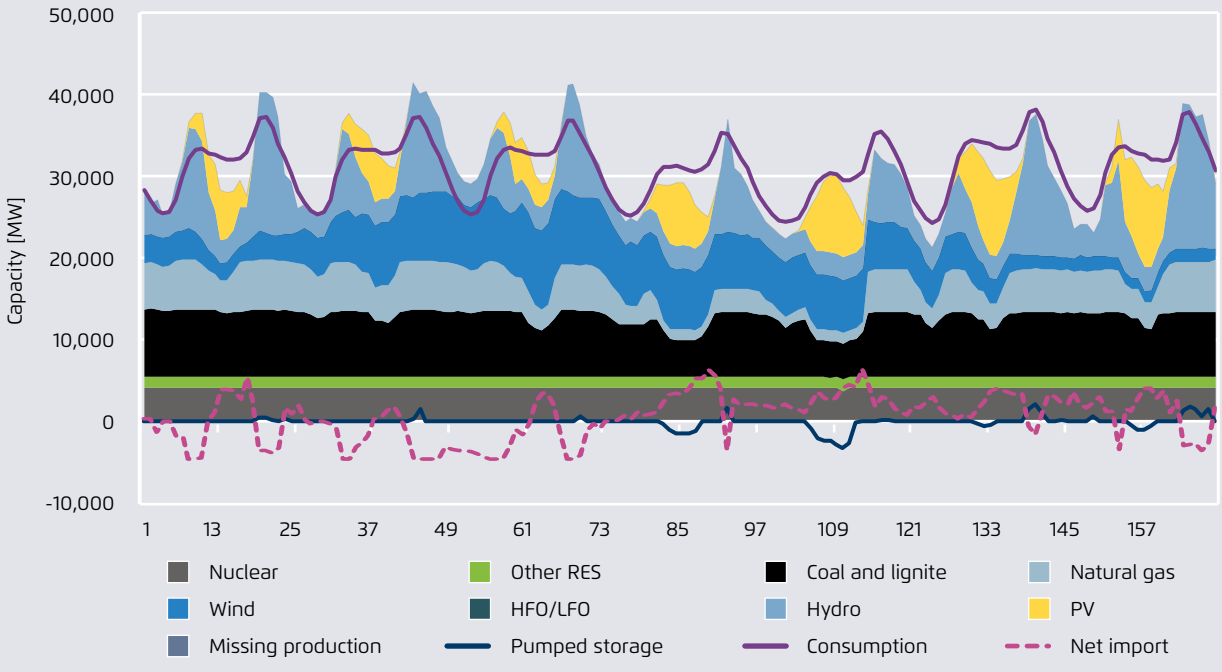
Note: The week starts on Wednesday, 0:00 and ends on Tuesday 24:00.

Electricity generation and demand in the SEE region for the critical spring week in 2030, MW Figure 13



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Note: The week starts on Wednesday, 0:00 and ends on Tuesday 24:00.

Reserve margin in the SEE region for the critical spring week in 2017, MW

Figure 14

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Note: The week starts on Wednesday, 0:00 and ends on Tuesday 24:00.

Reserve margin in the SEE region for the critical spring week in 2030, MW

Figure 15

REKK

Note: The week starts on Wednesday, 0:00 and ends on Tuesday 24:00.

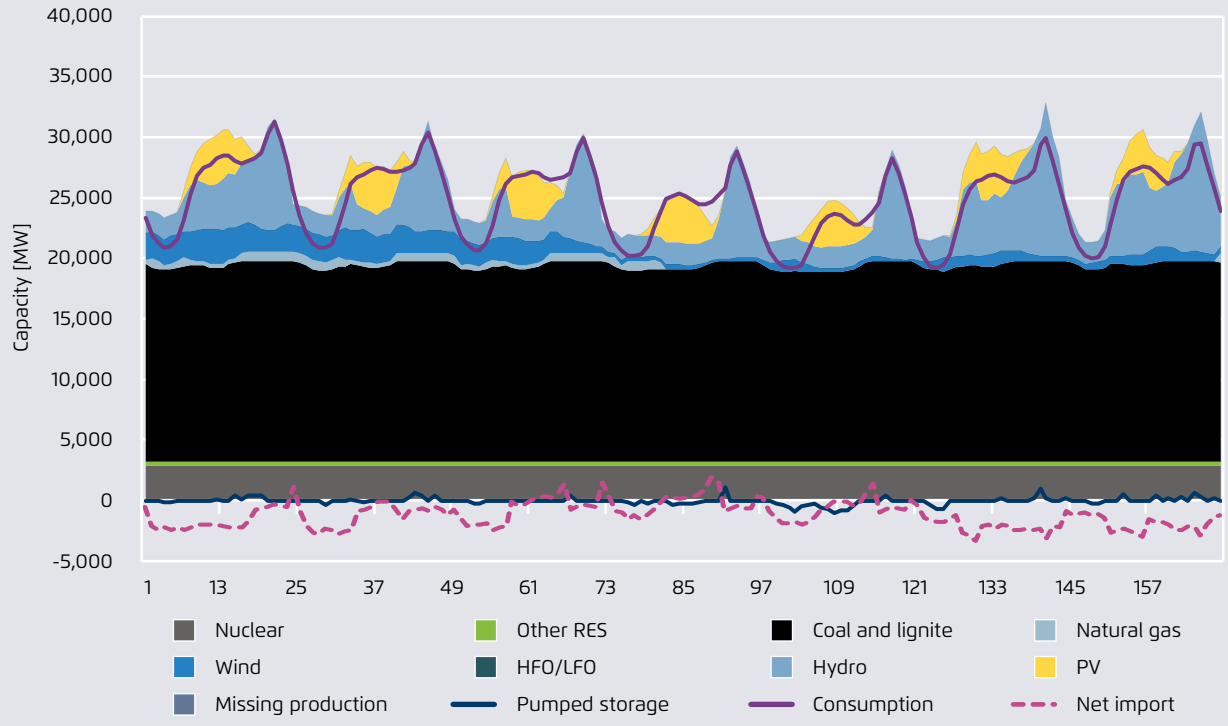
Margins drop in 2030 relative to 2017, though they remain above 40% for every hour of the critical week, maintaining a healthy reserve ratio even during peak hours. The margin is over 120% in off-peak periods (see Figure 15). This indicates that the region's abundant hydropower will be a very important source of flexibility and might also be utilized for neighbouring countries in seasons when hydropower is more readily available.

Summer season result

Summer consumption levels is the lowest of all the seasons. Thanks to higher RES output levels, the region served as a net exporter for many hours of the season in 2017. Load following was mainly provided by flexible hydropower and the adjustment of net export positions (see Figure 16). Within the critical week, wind power generation was much lower than in the spring season, whereas PV production was at the highest (as is expected). The figure below shows that the midday peaks in the region can be met by PV generation, while hydropower can step in for the evening peaks.

For 2030, hard coal and lignite are replaced by natural gas for economic reasons. Swings in consumption are mainly met and managed by flexible hydro, while PV contributes largely to meeting noon daytime peak hours (see Figure 17). Changing net export and net import positions during the course of the week show the large flexibility potential arising from the interconnected power systems. Due to the higher amount of PV-generated electricity during the daytime, some system flexibility must come from coal capacities. As a result, coal-fired plants will have to provide more load-following operation than in 2017.

Electricity generation and demand in the SEE region for the critical summer week in 2017, MW — Figure 16



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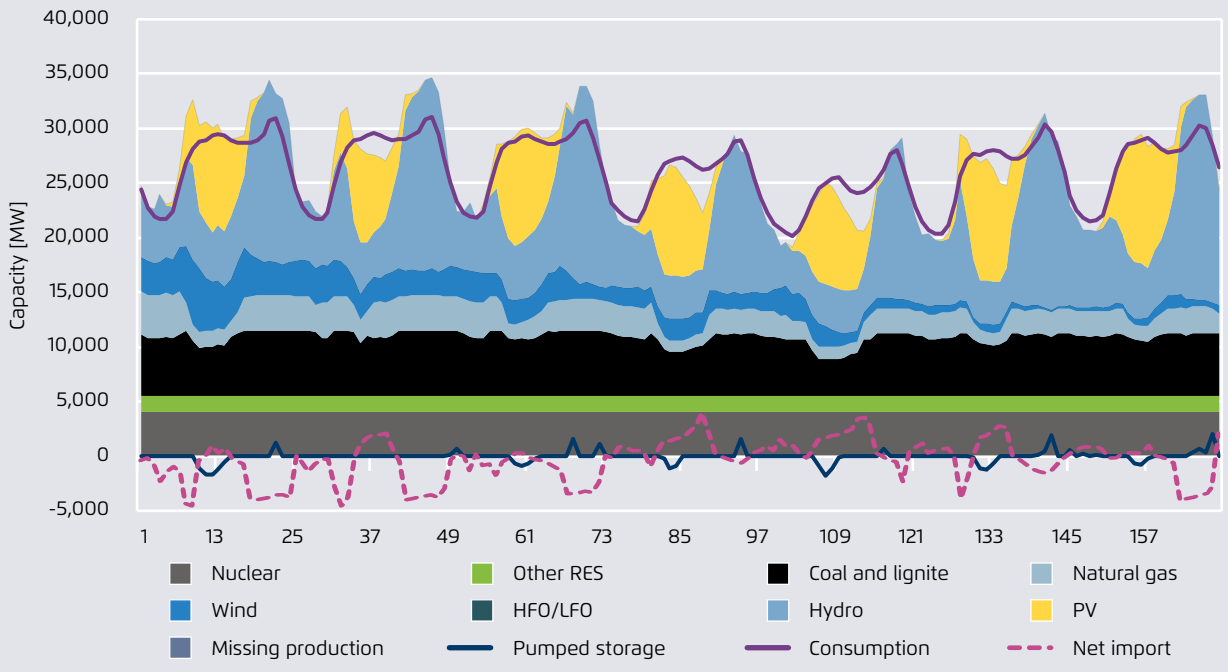
Note: The week starts on Wednesday, 0:00 and ends on Tuesday 24:00.

Electricity generation and demand in the SEE region for the critical summer week in 2030, MW

Figure 17



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Note: The week starts on Wednesday, 0:00 and ends on Tuesday 24:00.

Reserve margin in the SEE region for the critical summer week in 2017, MW

Figure 18

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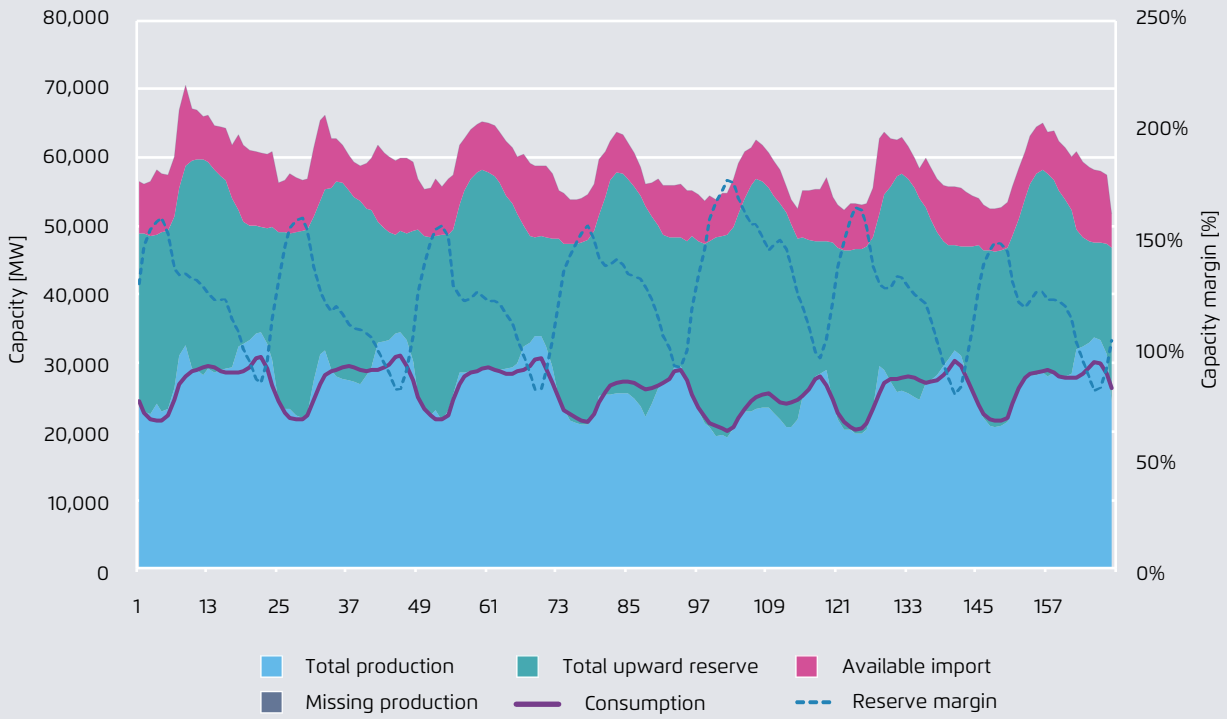
Note: The week starts on Wednesday, 0:00 and ends on Tuesday 24:00.

Reserve margin in the SEE region for the critical summer week in 2030, MW

Figure 19



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Note: The week starts on Wednesday, 0:00 and ends on Tuesday 24:00.

In 2017, a significant change occurred in the summer period with regard to reserve capacities. Consumption peaks were not as severe as in the winter season and renewable based resources, e.g. PV and reservoir hydro, were available. For this reason, the reserve margin was always above 100%, even during peak hours (see Figure 18).

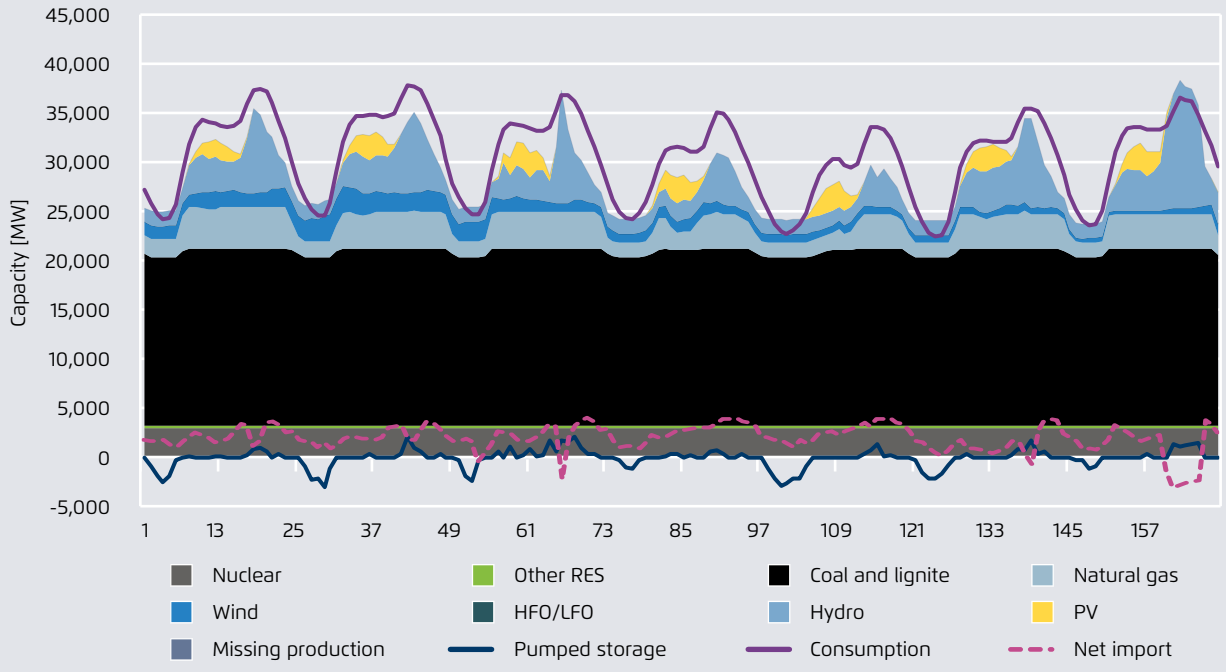
For 2030, the summer reserve margins have small dips but seldom drop below 100% relative to consumption levels. Figure 19 shows that the summer period is the best positioned season in terms of reserve capacities. Moreover, during normal years hydro reservoirs fill up in the spring, providing sufficient reserves for the summer.

The sensitivity assessment performed in the next section highlights the impact of low precipitation in the region. The results indicate that the region will be in a position to open its reserve capacities to neighbouring countries (e.g. Hungary) in those seasons and years when precipitation is sufficient to maximize hydro reserves.

Autumn season results

The critical autumn week in 2017 was characterized by higher imports in the region when hydropower generation is lower. This is due to the inflows into reservoirs, which are higher in the spring (and early summer) than in autumn. PV generation was also slightly lower relative to the summer season. In a week without wind generation, the utilization of gas-based plants and imports was greater. Accordingly, gas-fired plants also contributed to covering peak demand and providing flexible load-following services (see Figure 20).

Electricity generation and demand in the SEE region for the critical autumn week in 2017, MW Figure 20



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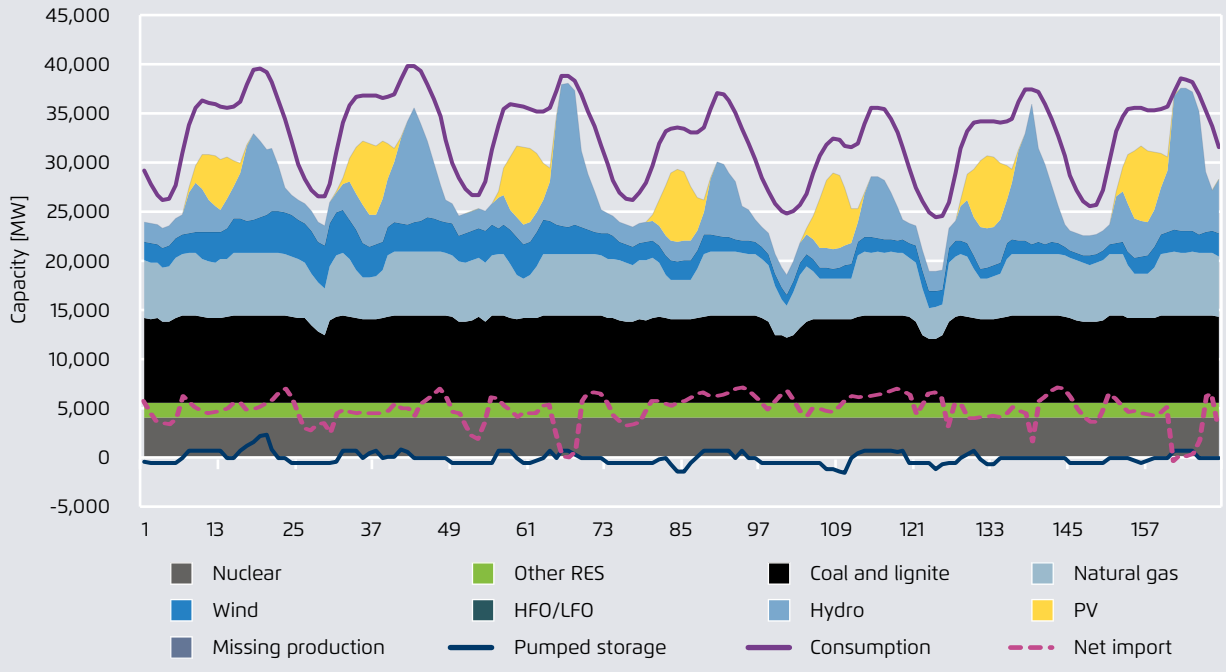
Note: The week starts on Wednesday, 0:00 and ends on Tuesday 24:00.

Electricity generation and demand in the SEE region for the critical autumn week in 2030, MW Figure 21



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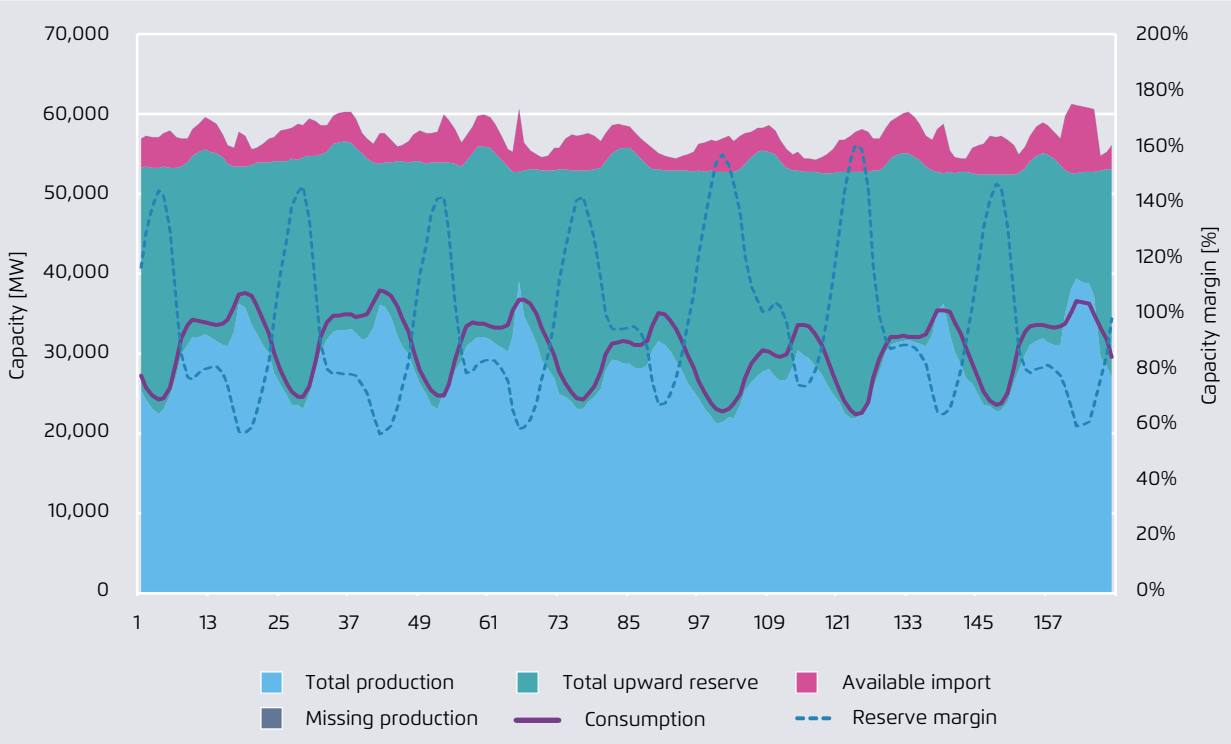
Note: The week starts on Wednesday, 0:00 and ends on Tuesday 24:00.

For 2030, net imports are projected to surpass 5 GW due to lower availability of hydro generation in autumn. Other regions in Europe will provide exports to the region that are cheaper than domestic/regional conventional generation. Imports are, therefore, a key flexibility option in autumn (see Figure 21). Although PV increases its contribution to the generation mix, natural gas-based production also provides a much higher share than in 2017 on account of its growing capacity. According to our scenario, the autumn season in 2030 will have the year's highest import level for the region.

In spite of the higher import levels, reserve margins for 2017 were usually above 100% (even in the range of 140%); in the most critical hours their levels were above 60% (see Figure 22). This represents a very healthy ratio for the region, even for peak periods.

For 2030, reserve margin levels are projected to fall relative to 2017 for all hours in the critical week. Margins do not exceed 100% in off-peak hours; in the most critical hours, they remain above 35% at the regional level. Nonetheless, the autumn season is likely to be the most vulnerable with regard to available reserve capacities due to the high dependency on of hydro-based generation in the region. In autumn, reservoirs fall to low levels even in normal years; accordingly, other flexible units and imports will have to be used more frequently. Nevertheless, regional reserves will remain at a comfortable 35% even during the most critical week of the year (see Figure 23).

Reserve margin in the SEE region for the critical autumn week in 2017, MW — Figure 22



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Note: The week starts on Wednesday, 0:00 and ends on Tuesday 24:00.

Reserve margin in the SEE region for the critical autumn week in autumn 2030, MW

Figure 23

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Note: The week starts on Wednesday, 0:00 and ends on Tuesday 24:00.

Sensitivity analyses: The impacts of different weather regimes and interconnection levels

We analysed 11 sensitivity scenarios covering various weather regimes and interconnectivity levels for 2030. Specifically, we assessed nine different weather types pertaining to hydro and PV/wind utilization rates:

- High, reference and low hydro yearly utilization rates based on historical data across Europe;
- High, reference and low PV/wind yearly utilization rates based on historical data across Europe.

We also assessed two sensitivity cases with varying levels of cross-border net transfer capacities. These cases represent important sensitivity considerations that serve as a proxy for modelling higher or lower interconnectedness in the countries. In case of low NTCs, countries might have to rely more on domestic capacities in peak hours to meet demand because cross-border capacities become constrained more frequently.

- The high NTC case: we assume that at all interconnection points the NTC values are 20% higher than in the base case.
- The low NTC case: we assume that at all interconnection points the NTC values are 20% lower than in the base case.

We performed sensitivity runs for 2030. Table 6 shows how the different cases correspond to the assumptions on the availability of hydro, PV and wind resources. In these sensitivity cases, we assumed the reference level for NTCs (see the Annex for the MW levels).

Figure 24 shows the number of start-ups for conventional power plants. Our 2030 reference case (Ref-2030) has 150% more start-ups than in the 2017 reference scenario (see the analysis at the beginning of the report).

The nine sensitivity cases on different weather conditions (varying levels of wind, PV and hydro availability) show the range of impacts on system volatility. The number of start-ups – an indicator of system volatility – ranges from -50% to +75% relative to the 2030 reference case. We were unable to observe a clear pattern in the sensitivity cases. In most weather-related sensitivity cases the number of start-ups increases, with the exception of the low hydro-ref PV/wind case, where start-ups of conventional power plants decrease. **The main reason for this rather unexpected result is that PV and wind generation patterns and hydro availability (dry or wet year) are not correlated.** Consequently, it may

Sensitivity cases of the various weather regimes. Table 6

	low PV/wind	**ref PV /wind**	**high PV/wind**
Low hydro	low_hydro_low_PV	low hydro_ref_PV	low_hydro_high_PV
Ref hydro	ref_hydro_low_PV	**Ref 2030**	ref_hydro_high_PV
High hydro	high_hydro_low_PV	high_hydro_ref_PV	high_hydro_high_PV

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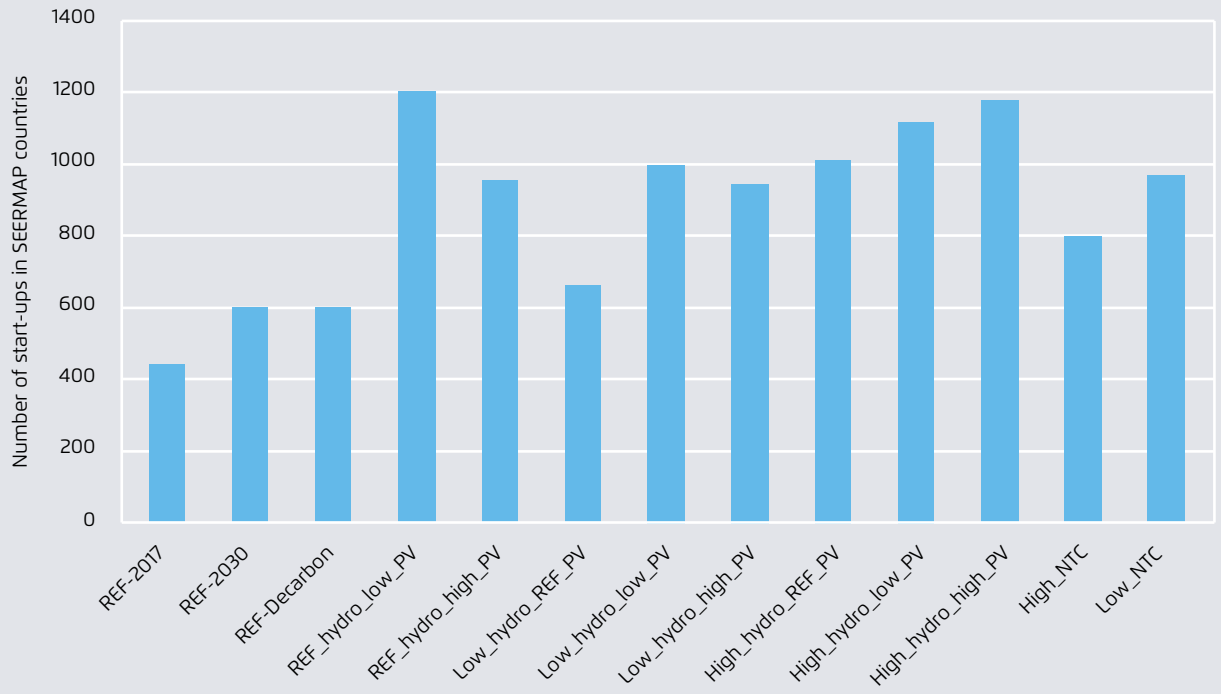
Number of unit start-ups in conventional power plants in SEE in all assessed scenarios Figure 24



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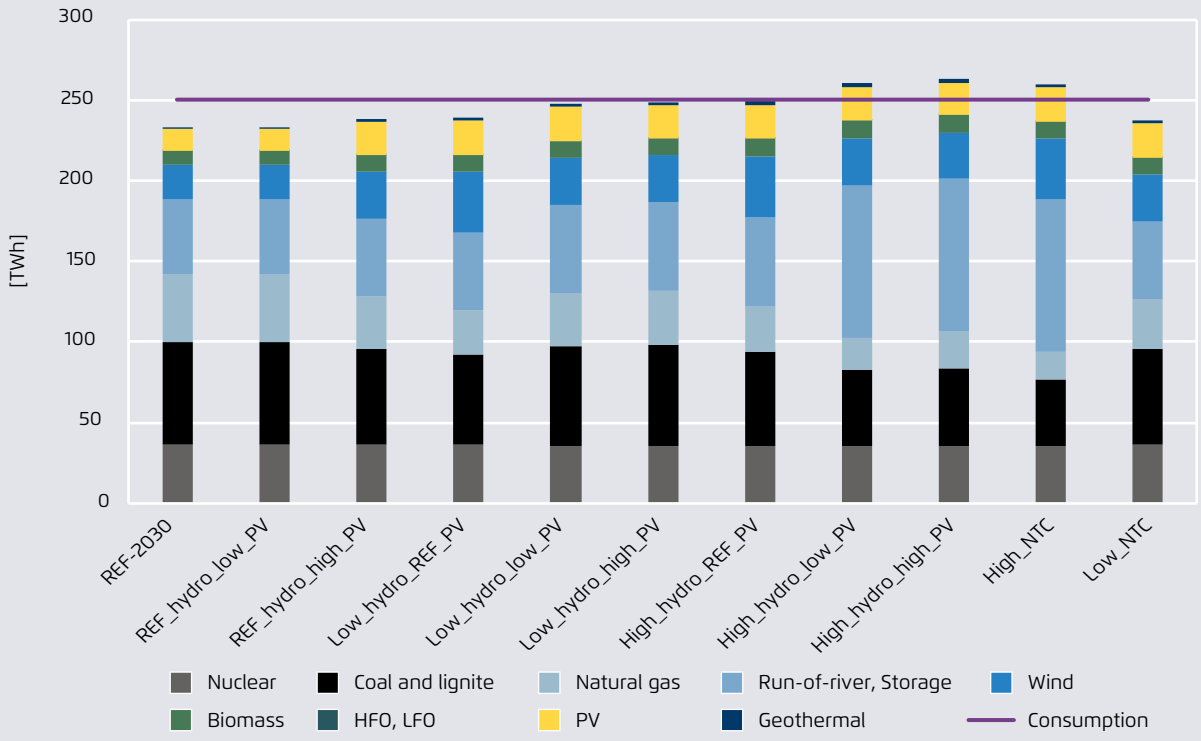
happen that in a dry year with low hydro availability and less volatility, more permanent wind conditions will prevail, which would offset overall system volatility. The decorrelation of various RES generation sources is thus an important enabler of vRES system integration.

The two cases with higher and lower values for NTCs are easier to explain because the results are in the expected directions. A lower level of transfer capacity in the region – 20% lower NTCs than in the reference scenario – would increase the number of start-ups because countries would have to balance their systems by relying more on power plants within their borders given the limited access to import. The higher NTC scenario (20% higher NTCs than in the reference scenario) does not increase the level of start-ups. This means that the planned NTC development in the region (in line with ENTSO-E's TYNDP) would reach a satisfactory level in the 2030 reference case.

If we look at the impact on the generation mix, hydropower will play a decisive role in 2030. Increased hydro – and to a somewhat lesser extent, wind and PV generation – will supplant fossil-fuel-based production (primarily coal and lignite and secondarily natural gas). In a year with high levels of precipitation, hydropower generation would be sufficient to change the position of the region from net importer to net exporter, even when PV and wind generation levels are lower than average. This result underlines the importance of regional cooperation: the inter-annual fluctuations in hydro-based generation (around 50% of the average annual generation levels) can be matched economically if sufficient transfer capacity is available within the region and between neighbouring countries. The higher reliance on im-

Electricity generation mix in SEE in all assessed scenarios, TWh/year Figure 25



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ports is already observable in the SEE region, but it will be even more important as renewables-based electricity generation increases.

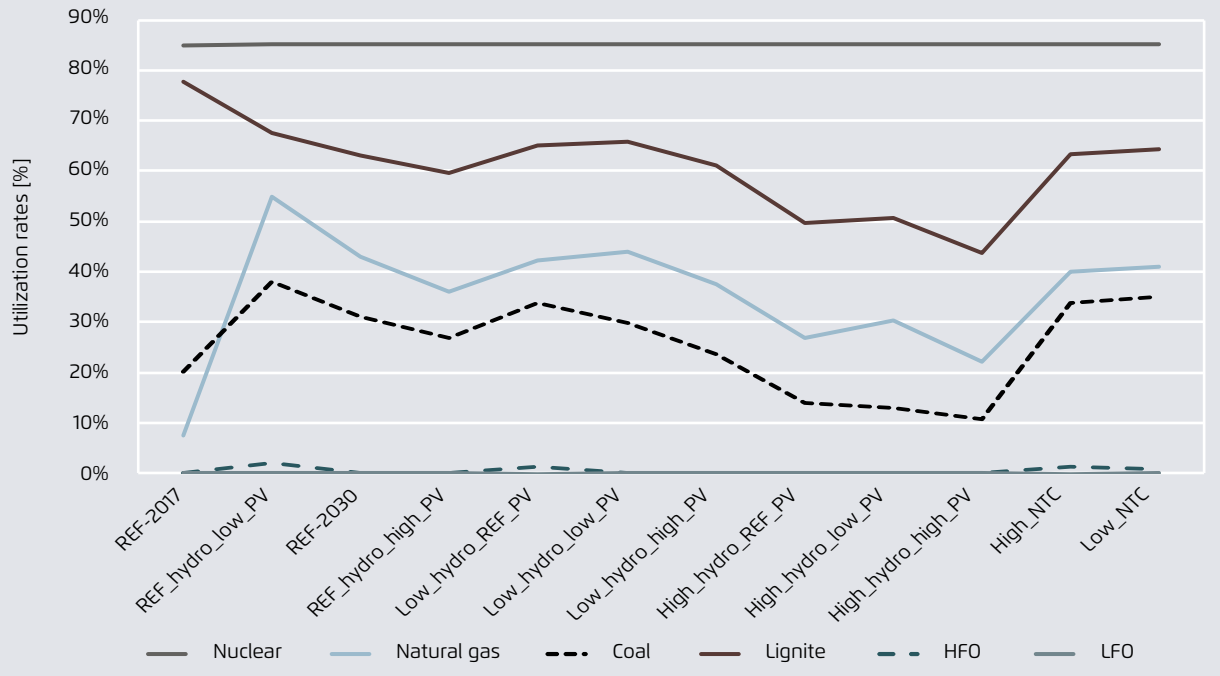
Figure 26 shows the utilization rates for conventional power plants. Utilization rates of hard coal and lignite plants are generally lower for scenarios with higher hydro or wind/PV utilization. The same holds true for natural gas-based generation. The lower utilization rates deteriorate the economic performance of the lignite and coal plants, which indicates the need for additional revenues from the balancing market in the long term to supplement revenues from the forward and day-ahead markets.

Figure 27 shows the non-satisfied demand for all scenarios. Non-satisfied demand amounts to only a few gigawatt hours in the reference case, and remains the same in most sensitivity cases.

As the figure illustrates, the most important impact on non-satisfied demand arises from altered NTC levels. With 20% higher NTCs, annual missing production drops to zero, while more than 240 GWh/year of demand is left unsatisfied (only 0.1% of regional power demand), with 20% lower NTCs. Three countries are primarily affected: Albania, Kosovo* and North Macedonia. This emphasizes the key role of interconnection capacity for security of supply.

Even though there is enough spare capacity on the regional level, the lack of interconnectors in the 20% lower NTC sensitivity case hinders the full use of power plants in neighbouring countries. This in turn causes unserved power demand (see Figure 28). It also underlines the importance of interconnection levels in the SEE region. The planned infrastructure development can help countries maintain the flexibility and security of supply of the regional system,

Non-RES utilization rates in the sensitivity scenarios in % Figure 26



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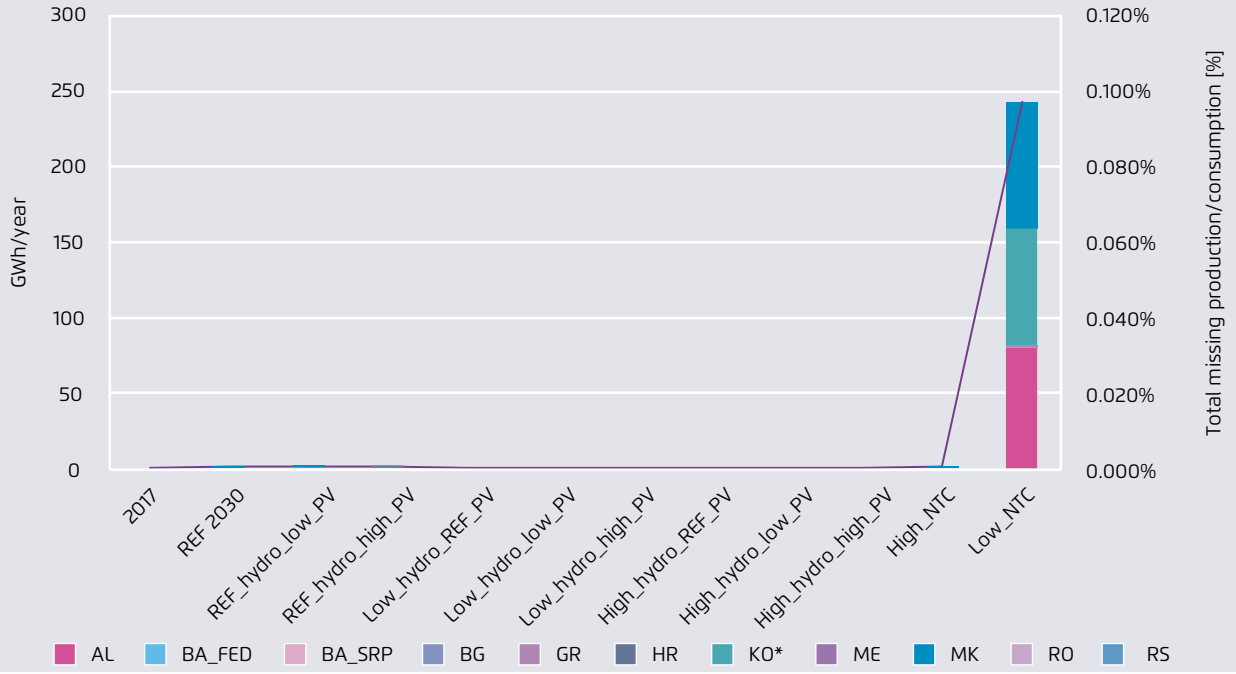
Missing production values (non-satisfied demand) for the sensitivity scenarios, GWh/year Figure 27



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Missing production in the low NTC case (critical autumn week of 2030) Figure 28

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Note: The week starts on Wednesday, 0:00 and ends on Tuesday 24:00.

though the lack of interconnectors can leave some countries vulnerable during certain critical hours.

Figure 28 illustrates the most critical week of 2030 – a week in autumn – when the highest values of unserved load occur. It shows the distribution of missing production over the week, mainly occurring over the peak demand hours, and also illustrates that these hours can occur on weekdays as well as on weekends. Both the prevailing demand level and the low level of production determine these critical hours.

Conclusions: Pathways for robust RES deployment and security of supply

With roughly half of the installed hard coal and lignite generation capacity in SEE requiring modernization or replacement in the next decade, a power system with much higher RES shares is about to emerge in the region. This is in line with the EU's 2030 targets for climate and energy, where RES-E shares of 57%[18] are to be expected.

Indeed, the 2030 SEE scenario assessed in this report finds that RES-E shares of 50% are realistic in terms of system flexibility, RES integration and security of supply. The scenario shows that the level of available upward reserve capacities will decrease relative to 2017 because of higher vRES penetration. The available upward reserve capacity margin will still be above 40% in the region during most hours, and only for a few hours per year (under 15 hours) will it fall to 35%. This indicates that a higher level of cross-border capacities within the SEE region would help maintain the system adequacy throughout all hours of the year. Moreover, the available downward reserve capacities will increase thanks to vRES potential to provide such services.

The results also indicate that the projected infrastructure developments of the Decarbonization scenario – characterized by major reductions of coal- and lignite-based generation and steadily increasing RES generation – will meet the growing demand of the region, achieving a nearly balanced net import position at the regional level by 2030. As coal and lignite production decreases, vRES production and gas-based generation will take their place (though the increase of gas-based generation will be confined to just a few countries in the region). Note that the annual average utilization of gas plants in the region is not projected to exceed 45% in 2030 for our sensitivity cases. Thus, the business model for conventional power plant operators is all about flexibility, not simply about the sale of kilowatt hours. If lignite utilization falls below 65%, lignite plants will have a hard time earning sufficient revenue from the power markets.

The critical week assessment shows that the reserve margin in the SEE system will stay above a healthy 35% even during critical hours of the assessed weeks, which presents a satisfying level for the region ensuring security of supply. At the same time, in most hours of the year the region maintains an even higher level of reserves: At over 100% of regional consumption, the SEE region will be able to provide flexibility services to neighbouring electricity systems such as those of Hungary and Slovenia, where flexible units are likely to be scarcer. The analysis has shown that the most critical season in SEE is autumn, where availability of hydro resources is limited due to lower water reservoir levels. This shows the need to diversify flexibility options through geography as well as technology.

The number of plant start-ups will also stay in the manageable range – below 40 start-ups a year for any conventional unit. By 2030, the system will have many dedicated flexible gas units; several coal and lignite plants will also contribute to the provision of system flexibility. Variable RES curtailment will remain low because hydro-based generation and the contribution of fossil-based generation to system flexibility will help avoid zero-cost vRES curtailment in 2030. This underlines the economic potential of efficient RES integration in the region.

18 Agora Energiewende (2019): European Energy Transition 2030: The Big Picture. Ten Priorities for the next European Commission to meet the EU's 2030 targets and accelerate towards 2050.

The sensitivity assessment shows that interconnections and market integration are key factors for maximizing the security of supply and providing the required flexibility for vRES deployment in the SEE region. In the case of increased network limitations, modelled by reduced NTC values, a limited level of non-satisfied demand will occur in Albania, Kosovo* and North Macedonia due to increased network limitations. This underlines the importance of continuing the implementation of the planned cross-border infrastructure developments. More importantly, market integration must be deepened among SEE countries in order to utilize available cross-border capacities efficiently. This not only brings security of supply benefits; it also has an economic rationale, as it gives the region greater access to the electricity markets of neighbouring countries in Central and Eastern Europe. Most importantly, SEE can provide flexibility services to these countries in seasons/years with higher levels of hydro availability.

In summary, alongside grid reinforcement, a diverse mix of flexible generation technologies in SEE (hydro technologies, flexible biomass, natural gas and storage) can facilitate the integration of vRES – especially wind and PV. In particular, reduced flexibility needs and increased system reliability can be achieved by integrating countries and regions with fundamentally different weather regimes. **An interconnected European power system would be highly beneficial for vRES integration.** Indeed, regional cooperation, stronger power systems and market integration will help minimize power system costs for consumers while maximizing supply security.

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ANNEX: Input data and assumptions

Assumed natural gas prices according to the latest EGMM modelling of the SEE region Table A1

€/MWh	2020	2030
AL	27.3	25.2
BA_FED	29.4	38.7
BA_SRP	29.4	38.7
BG	24.4	25.1
HR	27.2	25.2
KO	not available	not available
ME	not available	not available
MK	51.2	69
RO	23.1	23.4
RS	26.7	28.9

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Assumed new cross-border capacities in the SEE region, based on TYNDP and PECI projects Table A3

New cross-border capacities				
From	To	Year of commissioning	O → D	D → O
AL	KO	2016	500	500
ME	IT	2019	500	500
BG	RO	2020	1000	1200
AL	MK	2020	600	1000
ME	RS	2020	200	300
GR	BG	2021	0	650
MD	RO	2022	600	500
RS	RO	2023	600	600
ME	IT	2024	500	500
RS	BA	2024	450	200
ME	RS	2025	500	500
UA_E	RO	2026	1000	1000
GR	BG	2030	250	450

Source: TYNDP (2016), Energy Community

Available cross-border capacities in the SEE region in 2017 Table A2

Origin and destination country		NTC, MW	
From	To	O->D	D->O
BA_FED	HR	350	326
BA_SRP	HR	350	326
BA_SRP	ME	459	467
BA_SRP	RS	566	462
BG	GR	500	341
BG	MK	202	100
BG	RO	300	300
BG	RS	263	156
HR	HU	1000	1200
HR	RS	607	478
HR	SI	1466	1466
HU	RO	700	700
HU	RS	700	777
IT	GR	500	500
MK	GR	261	350
MK	RS	150	315
ME	KO	300	300
RS	ME	260	235
RS	RO	506	511
RO	UA_W	100	550
ME	AL	400	400
AL	GR	240	248
GR	TR	184	134
KO	RS	325	325
BA_FED	BA_SRP	no congestion	no congestion
KO	MK	150	291
KO	AL	208	219

O: Origin; D: Destination. Source: ENTSO-E, TYNDP 2016

Installed capacity in the region, MW — Table A4

		2015	2020	2025	2030
Lignite	-Existing	20 547	18 583	13 299	9 539
	-New	0	353	1 013	1 013
Coal	-Existing	2 801	2144	1284	504
	-New	0	0	0	0
Natural gas	- Existing	9 544	8 814	8 491	7 326
	- New	0	1 377	1 377	1 377
Nuclear	- Existing	3 413	3 413	3 413	3 413
	- New	0	0	0	1 400
HFO/LFO		2 990	2 781	2 305	1 009
Hydro		26 543	27 712	30 039	30 809
Wind		8 904	11 410	18 887	19 866
Solar		6 035	7 599	12 491	13 719
Other RES		1 500	2 059	2 874	3 353

REKK, ENTSO-E (2018)

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Stromwelten 2050 – Analyse von Erneuerbaren, kohle- und gasbasierten Elektrizitätssystemen

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Agora Energiewende develops scientifically based and politically feasible approaches for ensuring the success of the Energiewende. We see ourselves as a think-tank and policy laboratory, centered around dialogue with energy policy stakeholders. Together with participants from public policy, civil society, business and academia, we develop a common understanding of the Energiewende, its challenges and courses of action. This we accomplish with a maximum of scientific expertise, oriented towards goals and solutions, and devoid of any ideological agenda.

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