Decarbonisation modelling in the electricity sector

Regional Report

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Support for Low-Emission Development in South Eastern Europe (SLED)

December 2015
ACKNOWLEDGEMENTS

REC project management: József Feiler, Vaiva Indilaite, Ágnes Kelemen, Gordana Kozhuharova
Design and layout: Tricia Barna, Juan Torneros
Copyediting and proofreading: Rachel Hideg
Publisher: The Regional Environmental Center for Central and Eastern Europe (REC)
Photo credits: iStock

The REC is implementing the project “Support for Low-Emission Development in South Eastern Europe” (SLED) to help policy makers in the project countries (Albania, the former Yugoslav Republic of Macedonia, Montenegro and Serbia) to establish realistic but ambitious decarbonisation pathways for their electricity and building sectors by 2030.

The SLED project is funded by the Austrian Development Cooperation through the Austrian Development Agency (ADA). Special thanks are due to Hubert Neuwirth and Monika Tortschanoff of ADA.
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I. Executive summary
The objective of the project “Support for Low-Emission Development in South Eastern Europe (SLED)” is to help policy makers in Albania, the former Yugoslav Republic of Macedonia, Montenegro and Serbia to set realistic but ambitious decarbonisation pathways for their electricity sectors up to 2030. In the case of Montenegro and Albania, project results were also used in the assessment process for their intended nationally determined contributions (INDC).

This study assesses the effect of decarbonisation scenarios on electricity systems in the region, meaning the four project countries and Bosnia and Herzegovina.

The regional scenarios (Reference – REF; Currently Planned Policies – CPP; and Ambitious – AMB) use different assumptions related to electricity demand and supply. Supply side factors include the deployment levels of renewable energy sources for electricity (RES-E), changes in the conventional power generation sector, and the applied energy and carbon taxation rates. On the demand side, the energy efficiency ambition levels define the consumption scenarios. The scenarios and the assumptions were agreed with the main stakeholders in the project countries (relevant ministries, transmission system operator, regulator and electricity experts).

The assessment was carried out using the European Electricity Market Model (EEMM) developed by the Regional Centre for Energy Policy Research (REKK) and the network model of the Electricity Coordinating Center (EKC). The EEMM is a detailed, bottom-up economic simulation model covering the whole European Network of Transmission System Operators for Electricity (ENTSO-E) region, while the EKC network model covers the medium- and high-voltage network of the South East European (SEE) region.

The following main conclusions can be drawn from the scenario modelling:

- Self-sufficiency in generation in 2015 turns into a 20 to 30 percent export level in 2020 due to coal and hydro capacity expansion (the relative share depending on the scenario), after which this export share gradually decreases up to 2030. Other RES technologies remain at moderate levels throughout the whole period. Natural gas–based generation units are utilised at a very low level, despite the new capacities built in Albania, the former Yugoslav Republic of Macedonia, Serbia and Bosnia. Carbon leakage is present in the region after 2020, irrespective of the scenario or the year.
- The loss of hydro generation in years when there are unfavourable hydrological conditions is mainly substituted by imports in the first period (if it occurs up to 2020), then by coal- and lignite-based generation from 2025 onwards in most scenarios. In dry years up until 2020, hydro production is substituted mainly by imports, with a limited contribution from gas, while from 2020 onwards the new coal capacities gradually increase (in Serbia and Bosnia and Herzegovina) and take a complementary role alongside imports.
- A higher assumed European CO₂ price results in lower CO₂ emissions. In our modelling, in 2030 regional producers pay the European carbon price in all scenarios. Coal-based production decreases gradually and is substituted by imports. This decrease in production becomes more significant at a carbon price of EUR 40/t. Gas-based production is not competitive in the region: its utilisation becomes profitable at high carbon price levels.

The overall conclusion that can be drawn from these figures is the sensitive situation of the fossil-based generation capacities in the region. The most important drivers for their utilisation (both gas and coal) are:

- capacity expansion in coal- and gas-based generation;
- capacity expansion in hydro generation;
- infrastructure development in the gas networks; and
- carbon pricing in the region and in the EU.

The national energy strategies show that an important decision has to be made in almost all countries in the region: Should they substitute the currently ageing coal- and lignite-fired generation by new lignite/coal plants, or also plan gas-based combined-cycle gas turbine (CCGT) power plants? Gas-based power plants have lower investment costs but are subject to high risks related to production quantities due to uncertainties about the availability of competitive gas prices in the region. If these gas units do not operate economically, they will constitute sunk investments in the region. The dilemma is further complicated by other factors: What will be the long-term prevailing carbon price in the region? And how will demand change in the future? At higher carbon price levels (e.g. from EUR 35 to EUR 40) gas could gain a significant role in the region, which would reduce carbon emissions, and countries would avoid lock-in to expensive and carbon-intensive coal- and lignite-based generation.
Executive summary Figure 1 Regional generation mix (AL, BA, ME, MK, RS) and net imports in the three scenarios

Executive summary Figure 2 Change in the regional generation mix in the case of low hydro availability
Executive summary Figure 3 Regional generation mix with different CO₂ prices in the AMB scenario, 2030
II. Introduction
The main objective of the SLED project is to help policy makers in Albania, the former Yugoslav Republic of Macedonia, Montenegro and Serbia in setting up realistic but ambitious decarbonisation pathways for their electricity sectors up to 2030. Policy developments should be evidence based, as far as possible building on the quantified modelling results obtained from the possible set of future decarbonisation scenarios. The SLED project assisted the countries with modelling, accompanied by a continuous consultation process to enable national policy makers to influence scenario development according to their needs for their future energy sector and climate strategy developments. During the modelling exercise, policy options related to production levels and/or the fuel mix for electricity generation — such as supply-side energy efficiency improvements, the accelerated retirement of old power plants, increasing shares of renewable energy sources (RES), and electricity demand — were assessed from the perspective of CO₂ emissions, generation capacity investment costs and renewable support needs.

In addition to the individual country reports, the present regional analysis has been prepared in order to make possible an assessment of the potential synergies of more collaborative actions among the countries of South Eastern Europe (SEE). The modelling of the various options outlined above can help in the identification of the most effective options in the countries to reduce CO₂ emissions. Other impacts, such as those related to security of supply and network reliability, are also included in the analysis.

The present report focuses on regional aspects and contains less detailed information on the project countries themselves. Full details can be found in the individual country reports.
III. Methodology
In this section we introduce the regional scenarios, including the differentiation dimension, and the two models used in the assessment of the scenarios.

In this regional analysis, the scenarios prepared for the individual countries are aggregated into regional scenarios in the following way:

- **REFreg**: assuming the REF scenario of each project country (AL, MK, ME, RS)
- **CPPreg**: assuming the CPP scenario of each project country (AL, MK, ME, RS)
- **AMBreg**: assuming the AMB scenario of each project country (AL, MK, ME, RS)

Bosnia and Herzegovina — although not a project country — has been included in the regional analysis in order to better represent the electricity sector in the region. Bosnia and Herzegovina is represented in the analysis using a single scenario.

### Scenario development framework

In order to assess the full range of the decarbonisation potential in the project countries, three scenarios were constructed for each project country: Reference (REF); Currently Planned Policies (CPP); and Ambitious (AMB). Scenario assumptions were related to six dimensions:

- carbon value;
- energy/excise tax;
- environmental standards;
- deployment of renewable energy technologies;
- deployment of conventional generation technologies; and
- electricity demand (integrating assumptions on end-use energy efficiency improvement).

The above factors all affect national CO₂ emissions either via the level of electricity production or by their impact on the fuel mix for electricity generation. As far as taxation is concerned, two factors are identified. First, the introduction of the EU ETS either as a consequence of EU membership or the transposition of EU law required for members of the Energy Community; and second, simply the introduction of a national policy instrument placing value on carbon emissions, which alters the cost of the respective generation technologies and hence the production possibilities. The same logic applies to the introduction of the minimum tax level on energy products required by EU legislation.

The electricity supply mix is affected by the introduction of European air pollution regulations: the Large Combustion Plants (LCP) Directive, for example, may force the most polluting coal plants out of operation or limit their operating hours. The development of renewables and conventional (fossil) generation capacities is the outcome of national policy decisions and — in the case of renewables — support levels. Electricity demand growth triggers higher production from the available power plant portfolio or imports.

The REF scenario reflects the business-as-usual developments in the country, meaning that the official energy policy and legislative instruments that were in place by the closing date of the scenario definition (July 2015) are included. The CPP scenario reflects those policies that are under consideration and that could have an impact on GHG emissions. The third scenario, AMB, represents the most advanced climate policy stand.

### Models

Decarbonisation scenarios for the four assessed countries and the region as a whole were developed using the state-of-the-art European Electricity Market Model (EEMM), in tandem with the detailed technical network model of the Electricity Coordinating Center (EKC). The EEMM has been frequently applied in the region in the past in relation to Projects of Energy Community Interest (PECI) assessment, while the network model has been used in many network expansion and upgrade projects in the region. The EEMM is a partial equilibrium model focused on generation capacities, while the EKC network model focuses on the transmission system, in particular on the development of cross-border capacities. The two models are introduced briefly in this section: more detailed model descriptions can be found in the Annex.

The reliability of model results was ensured by working closely together with stakeholders in the region. The EKC network modelling team is from Serbia, which means that the modelling experts have in-depth regional knowledge. In addition to this insider involvement, three project factors gave unique added value to the assessment:

- The models were updated with the most recent data from the project countries, with the help of local experts.

The RELIABILITY OF MODEL RESULTS WAS ENSURED BY WORKING CLOSELY TOGETHER WITH STAKEHOLDERS IN THE REGION. THE EKC NETWORK MODELLING TEAM IS FROM SERBIA, WHICH MEANS THAT THE MODELLING EXPERTS HAVE IN-DEPTH REGIONAL KNOWLEDGE. IN ADDITION TO THIS INSIDER INVOLVEMENT, THREE PROJECT FACTORS GAVE UNIQUE ADDED VALUE TO THE ASSESSMENT:

- The models were updated with the most recent data from the project countries, with the help of local experts.
Throughout the project, the involvement of stakeholders — including representatives of relevant ministries dealing with climate- and energy-related issues and representatives of the transmission system operators (TSOs) — was ensured by setting up a project “task force”. These experts and policy makers were involved in defining policy-relevant scenarios and in the assessment of model results already at an early stage of the project. They also provided up-to-date information on national energy policies and checked the validity of information and data during two stakeholder meetings in November 2014 and July 2015.

The dissemination of project results will be ensured by means of workshops in all the participating countries and a regional workshop.

Relevant experts and stakeholders in the project countries were reached with the help of a local expert consultancy (EKC from Serbia), as well as the local offices of the Regional Environmental Center (REC), which has long-term expertise and a solid network in the region.

The European Electricity Market Model

The EEMM is a simulation model of the European electricity wholesale market that works in a stylised manner with perfect competition assumptions.

The EEMM covers 36 countries with rich bottom-up representation. In Figure 1, in the countries coloured orange, electricity prices are derived from the demand-supply balance, and in the blue countries prices are exogenous. The ENTSO-E countries of the EU (Malta and Cyprus are not included in the model) and Balkan countries are modelled in full detail.

In the electricity production sector we have differentiated 12 technologies. We assume one interconnector per pair of countries, which means modelling 85 transmission lines. The EEMM models the production side at unit level, which means that at a greater European level almost 5,000 units are included in the model runs. Equilibrium (in prices and quantities) is reached simultaneously in the producer and transmission segments. These units are characterised by various technological factors, allowing the construction of the merit order for the particular time period. In each year we have 90 reference hours to represent the load curve with sufficient detail for each European country.

There are three types of market participants in the model: producers, consumers and traders. All of them behave in a price-taking manner: they take the prevailing market price as given and assume that whatever action they decide upon has a negligible effect on this price.

Producers are the owners and operators of power plants. Each plant has a specific marginal cost of production, which is constant at the unit level. In addition, generation is capacity constrained at the level of available capacity.

The model takes into account only short-term variable costs with the following three main components: fuel costs, variable operational expenditure (OPEX), and CO$_2$ costs (where applicable). As a result, the approach is best viewed as a simulation of short-term (e.g. day-ahead) market competition.

Price-taking producer behaviour implies that whenever the market price is above the marginal generation cost of a unit, the unit is operated at full available capacity. If the price is below the marginal cost, there is no production at all; and if the marginal cost and the market price coincide, then the level of production is determined by the market clearing condition (supply must equal demand).

Consumers are represented in the model in an aggregated way by price-sensitive demand curves. In each demand period, there is an inverse relationship between the market price and the quantity consumed: the higher the price, the lower the consumption. This relationship is approximated by a downward sloping linear function.

Finally, traders connect the production and consumption sides of a market, export electricity to more expensive countries and import it from cheaper ones. Cross-border trade takes place on capacity constrained interconnectors between neighbouring countries. Electricity exchanges always occur from a less expensive country to a more expensive one, until one of two things happens: either prices, net of direct transmission costs or export tariffs, equalise across the two markets; or the transmission capacity of the interconnector is reached. In the second case, a considerable price difference may remain between the two markets.

The model calculates the simultaneous equilibrium allocation in all markets with the following properties:

- Producers maximise their short-term profits given the prevailing market prices.
Total domestic consumption is given by the aggregate electricity demand function in each country.

Electricity transactions (exports and imports) occur between neighbouring countries until market prices are equalised or transmission capacity is exhausted.

Energy produced and imported is in balance with energy consumed and exported.

Given our assumptions about demand and supply, market equilibrium always exists and is unique in the model.

**The EKC network model**

Electric power systems in SEE are modelled with their complete transmission networks at 400 kV, 220 kV and 150 kV. The power systems of Albania, the former Yugoslav Republic of Macedonia, Montenegro and Serbia are modelled, in addition, at the 110 kV voltage level. The network equivalent of Turkey (i.e. European part) and the rest of ENTSO-E Continental Europe (modelled over the X-node injections) are used in the model.

The network model in this assessment provides the following results:

Contingency analyses, which include:

- an assessment of the existing electricity network situation within Albania, the former Yugoslav Republic of Macedonia, Montenegro and Serbia, together with the regional context; and
- a definition of the network topologies and regimes for 2015, 2020 and 2025, using realistic scenarios of demand growth, generation expansion, transit flows, RES integration and high-voltage direct current (HVDC) links.

- Total and net transfer capacity (TTC/NTC) evaluation between Albania, the former Yugoslav Republic of Macedonia, Montenegro and Serbia in all directions, for all topology scenarios.

- An assessment of transmission grid losses with and without a level of energy production from RES.

**STEADY-STATE AND CONTINGENCY ANALYSES**

For the defined scenarios, steady-state load flows are calculated and contingency (n-1) analyses performed.
Security criteria are based on the loadings of lines and voltage profile, and are checked for each scenario analysed.

Load-flow assessment is a basic step for NTC evaluation, and it comprises the following analyses:

- steady-state AC load-flow analysis;
- a security (n-1) assessment, where the tripping of lines is simulated. This means that one line is considered to be out of service while load flow is calculated and the security of the system assessed (circuit overloads and voltage violations); and
- a voltage profile analysis.

In the analysis of voltage profiles, voltage limits are according to the respective national grid codes.

**EVALUATION OF NET TRANSFER CAPACITY**

Total and net transfer capacity (TTC/NTC) were evaluated between Albania, the former Yugoslav Republic of Macedonia, Montenegro and Serbia, as well as between these countries and their neighbours, in all directions and for all topology scenarios, with reference to each target year and regime, and a final assessment was made of the TTC/NTC additional values as a result of the new interconnections and the strengthening of major internal energy transit routes.

General definitions of transfer capacities (TTC and NTC) and the procedures for their assessment were given by ENTSO-E, as well as by the practice and experience of regional SEE TSO working groups.

The methodology used in performing this study was based on the prerequisites outlined below.

**TRANSMISSION GRID LOSSES**

The assessment of electricity losses is based on losses over the equivalent time duration in the winter peak and summer peak periods. This approach takes into account that the effect on losses may be different in these two regimes, as a result of which losses on a yearly level can be determined more accurately.

**Cross-border network capacities**

Even though countries in the SEE region are well connected with their neighbours, further capacity extensions are envisaged in the future. The model uses the NTC values of ENTSO-E to reflect the trading possibilities between countries. Tables 1 and 2 show the present NTC values in the region, including neighbouring countries, and the planned new connections in the modelling timeframe.

The Montenegro—Italy 1,000 MW submarine cable is planned to start operation in 2018. Construction has already started and is proceeding according to the investment plan. The other submarine cable connecting Italy with Albania is very uncertain and might not be realised as planned, or might even be cancelled. The modelling considers the “approved” and “under construction” categories of ENTSO-E in all three scenarios.

**Current generation capacities**

Table 3 provides information on electricity generation capacities for the base year, 2014.

**Fossil fuel prices**

Table 4 shows the fossil fuel prices applied in the modelling for the period 2015–2030.

**European Union Emissions Trading System price**

Concerning the carbon price assumptions, we followed the carbon value path of the latest impact assessment of the EU (GHG40EE scenario) and assumed an ETS carbon price of EUR 22/tCO₂ for Europe by 2030. The ETS price increases linearly from its 2014 value of EUR 6/t to EUR 22/t by 2030 in all scenarios.

**European Union minimum tax levels for energy products**

Excise duty is differentiated according to the fuel used (coal, natural gas and heavy fuel oil [HFO]). The minimum excise duty level applied is equal to the 2014 level applicable by EU law:

- EUR 0.3/GJ for natural gas;
- EUR 0.15/GJ for coal; and
- EUR 0.38/GJ for HFO.
### Table 1: Present net transfer capacity values in the region (MW)

<table>
<thead>
<tr>
<th>From</th>
<th>To</th>
<th>O→D</th>
<th>D→O</th>
</tr>
</thead>
<tbody>
<tr>
<td>AL</td>
<td>MK</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>BA</td>
<td>RS</td>
<td>488</td>
<td>403</td>
</tr>
<tr>
<td>BA</td>
<td>ME</td>
<td>483</td>
<td>440</td>
</tr>
<tr>
<td>GR</td>
<td>MK</td>
<td>329</td>
<td>151</td>
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<td>GR</td>
<td>AL</td>
<td>250</td>
<td>250</td>
</tr>
<tr>
<td>HR</td>
<td>RS</td>
<td>507</td>
<td>429</td>
</tr>
<tr>
<td>HU</td>
<td>RS</td>
<td>689</td>
<td>758</td>
</tr>
<tr>
<td>ME</td>
<td>AL</td>
<td>400</td>
<td>400</td>
</tr>
<tr>
<td>MK</td>
<td>BG</td>
<td>96</td>
<td>215</td>
</tr>
<tr>
<td>RO</td>
<td>RS</td>
<td>570</td>
<td>347</td>
</tr>
<tr>
<td>RS</td>
<td>ME</td>
<td>540</td>
<td>583</td>
</tr>
<tr>
<td>RS</td>
<td>MK</td>
<td>491</td>
<td>253</td>
</tr>
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<td>RS</td>
<td>AL</td>
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<tr>
<td>RS</td>
<td>BG</td>
<td>162</td>
<td>250</td>
</tr>
</tbody>
</table>

*Source: ENTSO-E*

### Table 2: Planned interconnectors and their investment status (MW)

<table>
<thead>
<tr>
<th>Country 1</th>
<th>Country 2</th>
<th>Year of commissioning</th>
<th>Investment status</th>
<th>O→D</th>
<th>D→O</th>
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<tr>
<td>RS</td>
<td>RO</td>
<td>2017</td>
<td>Approved</td>
<td>800</td>
<td>800</td>
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<tr>
<td>BA</td>
<td>ME</td>
<td>2023</td>
<td>Planned</td>
<td>600</td>
<td>600</td>
</tr>
<tr>
<td>IT</td>
<td>AL</td>
<td>2020</td>
<td>Planned</td>
<td>500</td>
<td>500</td>
</tr>
<tr>
<td>RS</td>
<td>MK</td>
<td>2015</td>
<td>Under construction</td>
<td>400</td>
<td>1,000</td>
</tr>
<tr>
<td>MK</td>
<td>AL</td>
<td>2019</td>
<td>Approved</td>
<td>600</td>
<td>600</td>
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<tr>
<td>AL</td>
<td>RS</td>
<td>2016</td>
<td>Under construction</td>
<td>500</td>
<td>500</td>
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<tr>
<td>IT</td>
<td>ME</td>
<td>2018</td>
<td>Under construction</td>
<td>1,000</td>
<td>1,000</td>
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<tr>
<td>RS</td>
<td>BA</td>
<td>2022</td>
<td>Planned</td>
<td>600</td>
<td>600</td>
</tr>
<tr>
<td>RS</td>
<td>ME</td>
<td>2022</td>
<td>Planned</td>
<td>600</td>
<td>600</td>
</tr>
</tbody>
</table>

*Source: ENTSO-E*
### Table 3: Electricity generation capacities, 2014

<table>
<thead>
<tr>
<th></th>
<th>Coal and lignite</th>
<th>Natural gas</th>
<th>HFO/LFO</th>
<th>Hydro</th>
<th>Wind</th>
<th>Biomass</th>
<th>PV</th>
<th>Total</th>
</tr>
</thead>
<tbody>
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<td>AL</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>1,801</td>
<td>0</td>
<td>5</td>
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<tr>
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<td>3,916</td>
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<td>ME</td>
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<td>0</td>
<td>0</td>
<td>661</td>
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<td>881</td>
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<td>RS</td>
<td>4,672</td>
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<td>7</td>
<td>7,368</td>
</tr>
</tbody>
</table>

Source: REKK and PLATTS database

### Table 4: Fuel prices, 2015–2030

<table>
<thead>
<tr>
<th></th>
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<td>2.2</td>
<td>1.3</td>
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<td>8.3</td>
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</table>

Source: IEA and EIA projections

1 In the network assessment of the 400 kV line between Montenegro, Serbia and Bosnia and Herzegovina, for example.
IV. Scenario assumptions
Tables 5 and 6 summarise the country-level scenario assumptions for the four project countries that constitute the regional scenarios. Bosnia and Herzegovina — as a non-project country — is included in the regional analysis due to its geographical proximity. Assumptions regarding Bosnia and Herzegovina are simpler: the same assumption for taxation as the four project countries, but a single scenario for supply and demand developments. Table 5 shows the taxation variables that are constant across the assessed countries (and Bosnia and Herzegovina). Table 6 summarises the supply- and demand-side assumptions for all four project countries and the three scenarios.

### Environmental standards enforcement

#### ALBANIA
We assume that the country fulfils the requirements of the EU LCP Directive, which means that the Fier oil-fired TPP will not be in operation in the modelled period.

#### FORMER YUGOSLAV REPUBLIC OF MACEDONIA
Oil-based electricity generation is phased out from 2015. For the existing Bitola TPP, a desulphurisation system (LCP Directive) is due to be introduced in 2017. Oslomej TPP is due to be refurbished and upgraded and closed between 2016 and 2020. The closure of Bitola for 2017 is only assumed in the REF scenario.

#### MONTENEGRO
Montenegro complies with the EU LCP Directive, which means that the Pljevlja I coal-fired plant will be closed in 2023 at the latest and can operate for only 20,000 hours between 2018 and 2023.

#### SERBIA
Thermal power plants with a capacity below 300 MW are on average 45 years old and operate at 30 percent efficiency. The Energy Strategy envisages the gradual withdrawal of these lignite units. Altogether 11 power plants are assumed to be closed in the modelling period between 2016 and 2025.

### Introduction of the European Union Emissions Trading System

We used different assumptions for the project countries (and Bosnia and Herzegovina) regarding joining the EU ETS. In the REF scenario, the assessed countries join the ETS in 2025, while in the CPP scenario the power sector already faces carbon value equaling 40 percent of the EU ETS price in 2020. In the AMB scenario, the power sector joins the ETS already in 2020. “Joining the ETS” does not necessarily imply EU membership: we only assume that national policy makers will apply some instruments with similar effects on the electricity sector as the EU ETS (e.g. by a voluntary or legal obligation, through a national commitment or Energy Community commitments).

### Introduction of minimum excise duty on energy products

Concerning other taxes in the energy sector, we used the assumption that the countries introduce the minimum level of excise duties in 2020 in the REF and CPP scenarios, while in the AMB scenario it is already introduced in 2018.

### Deployment of renewable energy sources for electricity

The scenarios assume normal utilisation conditions for weather-dependent technologies (solar and wind), meaning average working hours and efficiency. Concerning hydro generation in these scenarios, average hydrological conditions are assumed (Table 7). This assumption is relaxed in the sensitivity assessment, where a low precipitation pattern is also assessed.
The EEMM treats RES-E capacities in a “must run” operation mode to reflect the priority dispatch of renewable technologies.

ALBANIA
The revised NREAP provides planned capacity values up to 2020. Figures beyond 2020 are based on the USAID document “Assessment of Energy Developments in Albania for the Period 2012–2030”, which contains forecasts up to 2030.

FORMER YUGOSLAV REPUBLIC OF MACEDONIA
All the RES-E deployment scenarios used are taken from the MARKAL modelling carried out by the Research Centre for Energy and Sustainable Development of the Macedonian Academy of Sciences and Arts with the following cross-reference:
- REF scenario – WOM (without measures) scenario of the MARKAL model;
- CPP scenario – WEM (with existing measures) scenario of the MARKAL model; and
- AMB scenario – WAM (with additional measures) scenario of the MARKAL model.

MONTENEGRO
Montenegro finalised its NREAP for the Energy Community Secretariat in December 2014. The NREAP provides planned capacity values up to 2020. Figures beyond 2020 are based on the Energy Strategy Development document of 2012 that forecasts up to 2030 with the condition that hydro capacities are kept constant at the 2020 level in the REF and CPP scenarios.

SERBIA
Up until 2020, all scenarios use the NREAP figures. From 2020 onwards, the REF scenario assumes the moderate expansion of hydro and wind capacities. The AMB scenario allows for a strong growth of hydro (2,000 MW newly installed) and the doubling of wind capacities. The CPP scenario uses the average of the REF and AMB scenario values in the respective years (2025 and 2030).

Conventional power plants

ALBANIA
Albania is planning to build two gas-fired CCGT plants in the future: Vlora I is planned to come online by 2020 with a capacity of 200 MW; and Vlora II is due to come online in 2025 with a capacity of 160 MW. However, it should be emphasised that these plants are conditional on the construction of a gas pipeline to provide natural gas to the SEE region.

FORMER YUGOSLAV REPUBLIC OF MACEDONIA
Apart from the refurbishment of the Bitola and Oslomej lignite power plants and the phase-out of oil-fuelled capacities, the country plans to put into operation the following fossil-based power plants:
- gas-fired CCGT (440 MW) in 2019;
- Bitola 4 (200 MW) in 2025;
- coal-fired plant (200 MW) in 2028; and
- coal-fired plant (400 MW) in 2030.

These new capacities are only assumed to be put into operation in the REF scenario.

MONTENEGRO
Pljevlja I is scheduled to be closed down in 2023 and is allowed only a limited number of operating hours (20,000 hours between 2018 and 2023). National energy policy plans to replace the power plant with a new block with a capacity of 254 MW (Pljevlja II). The earlier Energy Strategy of Montenegro (2012) also counted on building an additional coal plant (TPP Maoce), although its construction is no longer envisaged. In the AMB scenario, Pljevlja II is assumed to use 10 percent biomass (co-firing).

SERBIA
Serbia plans to put into operation several fossil fuel-based power plants. The construction of CHP Novi Sad (440 MW) and CHP Pancevo (190 MW) is foreseen in all scenarios. The construction of the
### Table 6: Scenario assumptions for the project countries

<table>
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<tr>
<th>Scenario assumptions</th>
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<td>MK</td>
<td>RS</td>
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<td><strong>Conventional capacity developments</strong></td>
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<tr>
<td>Closure of Negotino. Refurbishment of Bitola and Oslomej. New capacities: gas-fired CCGT (440 MW); Bitola 4 (200 MW); coal (200 MW); coal (400 MW).</td>
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<td><strong>Electricity demand</strong></td>
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<td></td>
</tr>
<tr>
<td>KAP operates at 100% capacity from 2019.</td>
<td>WOM of MARKAL model.</td>
<td>REF scenario of Serbian Energy Strategy plus Kosovo.</td>
<td>KAP operates at 50% capacity.</td>
</tr>
</tbody>
</table>
Kolubara B (630 MW) and Kosova e Re Power (600 MW) lignite power plants is assumed only in the REF and CPP scenarios, while the construction of the Kostolac B3 (320 MW) and Nikola Tesla B3 (675 MW) plants is assumed in the REF scenario exclusively.

**Electricity demand**

Electricity consumption usually closely follows a country’s GDP development. Rather than preparing our own forecast based on GDP assumptions, we aggregated the latest official energy forecasts of the project countries (Table 8). The demand assumption used for Bosnia and Herzegovina is shown in Table 8a.

### Table 6 Scenario assumptions for the project countries

<table>
<thead>
<tr>
<th>Scenario assumptions</th>
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<th>AMB</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>MK</td>
<td>RS</td>
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Table 7 Capacity deployment of renewable energy sources for electricity in the scenarios in the four countries (MW²)

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<td>Wind</td>
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<td>5,735</td>
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<tr>
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<td>49</td>
<td>73</td>
<td>196</td>
<td>389</td>
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*Excluding pumped storage
Table 8 Gross electricity consumption in the four project countries (GWh)

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<td>60,801</td>
<td>61,406</td>
<td>62,014</td>
<td>63,815</td>
<td>64,431</td>
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<td>58,571</td>
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<td>58,729</td>
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<td>56,093</td>
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<td>63,802</td>
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Table 8a Gross electricity consumption in Bosnia and Herzegovina (GWh)

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<td></td>
<td>11,780</td>
<td>11,949</td>
<td>12,135</td>
<td>12,323</td>
<td>12,514</td>
<td>12,709</td>
<td>13,726</td>
<td>14,825</td>
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</tbody>
</table>

3 For country-level data, see the individual country reports.
4 For country-level data, please see the individual country reports.
V. Modelling results
In this section we discuss the results of the modelling related to wholesale price development, the electricity generation mix, CO₂ emissions, renewable support and the investment needs for the generation capacities included in the respective scenarios.

**Price development**

One of the most important indicators of the functioning of an electricity market is the development of the wholesale price. Sudden and significant price changes are a sign of the malfunctioning of the electricity market, as they generally indicate shortages of certain generation capacities or problems with cross-border trade. As hydro capacities are an important source of the electricity generated in the region, changes in precipitation patterns can also change the price pattern in the electricity sector. This issue is addressed in Section VI (Sensitivity assessment).

Figure 2 shows the base-load price development in the region in the various scenarios. The figure shows the yearly base-load price development, as the calculated average of the modelled base-load hours of the year. In this way it is possible to smooth out the cyclical behaviour of electricity prices over a year to illustrate the main trends.

Wholesale prices decrease in 2020 and then subsequently rise gradually. This is due to the dynamic capacity extension in this period in the region. As far as country comparisons are concerned, Bosnia and Herzegovina has the lowest price in the period due to the inexpensive generation in its lignite plants, and Albania has the highest, especially in 2015. The price differences across the countries disappear by 2030. The REF scenario is generally more expensive than the CPP and AMB scenarios, with the exception of 2020, when the price difference is due to the different assumptions related to CO₂ price.

One of the most important things shown by the figure is the minor differences between the scenarios. While there is a big fluctuation in price between the years, there is no significant variation between the scenarios, with the exception of Bosnia and Herzegovina in

![Figure 2 Base-load prices in the various scenarios (EUR/MWh)](image)
2020. In this case, the price difference is exclusively due to the $\text{CO}_2$ price assumptions used in the scenarios, as the capacity mix is the same across the scenarios. This shows that, in terms of wholesale price, the more ambitious GHG policies are feasible, thus generation (together with import possibilities) would be able to cope with the assumed GHG policy instruments without any significant price increase.

Another interesting trend is the reduction in peak-load prices, which move closer to the base-load price by 2030. Increasing connectivity and more abundant capacities make shortages on the supply side less frequent, which, in turn, results in the convergence of base and peak prices, as illustrated by Figure 3. The same conclusion holds for both peak-load and base-load prices: the scenarios do not cause any significant differences in wholesale market prices.

**Regional outlook**

The plummeting price trend in the first five years requires a more detailed explanation. The main driving force behind this development is the dynamic capacity expansion in the region. As the countries in the region are well connected with their neighbours, any significant increase in generation capacities in any of the countries will increase supply and will reduce prices in the region as a whole. As Figures 4 and 5 illustrate, there is a significant peak in the construction of new power plants in the region between 2015 and 2020.

As the figures illustrate, most of the new fossil-based generation is planned to be built in the next five years, meaning a significant and quite rapid increase on the generation side. This increase in generation is complemented by an even more sizeable increase in renewable capacities, mainly wind and hydro. All these new plants mean significant pressure on the supply side, and if realised they will lead to significant price reductions in the coming years. As many of these plants are under construction or have the final investment decision (FID), they will probably be built even in an environment of falling electricity prices. Under these investment conditions, project developers are trying to finalise their projects as soon as possible, as new entrants will

**Figure 3** Peak-load price evolution in the various scenarios (EUR/MWh)
**Figure 4** Planned new fossil fuel-based capacities in South Eastern Europe, 2015–2030

![Graph showing planned new fossil fuel-based capacities in South Eastern Europe, 2015–2030](source: EEMM database, Platts)

**Figure 5** Planned new renewable-based capacities in South Eastern Europe, 2015–2030

![Graph showing planned new renewable-based capacities in South Eastern Europe, 2015–2030](source: EEMM database, Platts)
deter other investors from entering the market. However, this might lead to a situation in which all new entrants lose money, as the falling price trend would undermine the long-term profitability of the fossil fuel–based plants (mainly coal-based generation), especially if accompanied by an increasing carbon price trend.

**Generation mix**

While we can observe less-pronounced changes in wholesale electricity prices, the various policies have profound impacts on the electricity generation mix and on the export-import position of the region as a whole (Figure 6).

The key change during the observed period is that self-sufficiency in terms of generation in 2015 turns into a 20 to 30 percent export share in 2020 due to coal and hydro capacity expansion, after which the share of exports gradually decreases until 2030. Other RES technologies remain at moderate levels throughout the whole period. Natural gas–based generation units are not operated, despite the new capacities built in Albania, Bosnia and Herzegovina, the former Yugoslav Republic of Macedonia and Serbia. Carbon leakage is present in the region after 2020, irrespective of the scenario or year.

Figures 7, 8, 9 and 10 show the disaggregation of the regional generation mix and net import position in the five countries in the analysed years (2015, 2020, 2025 and 2030).

In Bosnia and Herzegovina, Serbia and the former Yugoslav Republic of Macedonia, coal-based production dominates until 2025 in all scenarios. In 2030 — especially in the AMB scenario — renewables and fossil fuels are on a more equal footing. Montenegro mainly produces from hydro resources in the observed period, irrespective of the scenario, with a limited but constant fossil-based share. Albania's domestic production is based exclusively on hydropower: other renewable technologies appear only in 2025.

**Figure 6** Regional generation mix (Albania, Bosnia and Herzegovina, Former Yugoslav Republic of Macedonia, Montenegro and Serbia) and net imports in the three scenarios
Albania’s high share of imports (40 percent) in 2015 falls to approximately 30 percent by 2020, then becomes sensitive to the scenario: more robust hydro capacity expansion translates into self-sufficiency, and even export options. The very strong export position of Bosnia and Herzegovina increases further from the 47 percent level of 2015 to 66 percent in 2030. Montenegro is close to self-sufficiency in 2015 and 2020. From 2025 onwards its export position depends on the scenario chosen: imports in the REF and CPP scenarios, and exports in the AMB scenario. The pattern is quite similar for the former Yugoslav Republic of Macedonia, with the exception that the 2030 AMB scenario does not allow for exports. Serbia is a net exporter from 2020 onwards, although its export position becomes weaker in the CPP and AMB scenarios due to the more limited fossil capacity expansion assumptions in these scenarios.

**CO₂ impacts**

In this section we assess the CO₂ emission impacts of the various scenarios and the fiscal impact of the introduced carbon and energy taxes.

Figure 11 shows that Serbia is the dominant emitter in the region. The CO₂ impact of the various scenarios is highest in the case of Serbia due to the big differences in the assumed new fossil capacities and changes in electricity demand. The impact of CO and energy taxes and of RES deployment is insignificant compared to the assumption of new fossil capacities. Albania remains CO₂ free, as the planned gas power plants are not utilised.

Excise and carbon taxes mean government revenues from the electricity sector. As Figure 12 shows, carbon revenues are significantly more important sources than excise taxes on energy products. Due to the stepwise introduction of the ETS carbon price from 2020, the revenue streams show an increasing trend, reaching around EUR 650 to EUR 1,100 million by 2030. This revenue level would be sufficient to compensate the hypothetical regional RES support budget from 2025 onwards, regardless of the scenario chosen.

**Investment costs**

More stringent climate policies targeting the electricity sector translate into different investment costs, as shown in Table 9 (page 35).

The sources of information concerning unit investment cost (shown in the second column, EUR/kW) are a 2013 publication by the Fraunhofer research organisation\(^6\); and the Serbian Energy Strategy, which gives region-adjusted values for the investment costs. While most of the renewable- and natural gas–based estimates are in a similar range, estimates in the case of the hydro and coal generation investment costs deviate significantly. We use benchmark investment cost values, as national quotes generally underestimate costs.\(^7\)

Overall new capacities and the overall associated costs are almost equal in the three scenarios, with figures 10 to 15 percent higher in the AMB scenario. Lower coal investments in the AMB scenario are outweighed by the increase in more expensive hydro capacities. While the unit investment cost is higher for hydro than for solar or wind technologies, the levelised cost of electricity (LCOE) in the case of hydro technology is lower than for wind or solar. In addition, its higher utilisation rates and regulatability makes hydro more attractive in the region. On the other hand, hydro generation raises greater environmental concerns, as the construction of new dams and reservoirs is generally more difficult now and many of the newly planned hydro plants are located in environmentally sensitive areas.
**Figure 7** Electricity mix in the five countries in the three scenarios, 2015

**Figure 8** Electricity mix in the five countries in the three scenarios, 2020
**Figure 9** Electricity mix in the five countries in the three scenarios, 2025

**Figure 10** Electricity mix in the five countries in the three scenarios, 2030
**Figure 11** CO₂ emissions in the five countries, 2015, 2020, 2025 and 2030

**Figure 12** Revenues from the Emissions Trading System and excise tax
Table 9 Cumulated investment costs in 2015–2030 in the three scenarios

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</tr>
<tr>
<td>Solar</td>
<td>1,100</td>
<td>119</td>
<td>221</td>
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<td>335</td>
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<td>Wind</td>
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<td>1,528</td>
<td>596</td>
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<tr>
<td>Biomass</td>
<td>3,000</td>
<td>209</td>
<td>319</td>
</tr>
<tr>
<td></td>
<td></td>
<td>461</td>
<td>626</td>
</tr>
<tr>
<td></td>
<td></td>
<td>957</td>
<td>1,383</td>
</tr>
<tr>
<td>Total</td>
<td>–</td>
<td>10,649</td>
<td>10,339</td>
</tr>
<tr>
<td></td>
<td></td>
<td>11,572</td>
<td>20,262</td>
</tr>
<tr>
<td></td>
<td></td>
<td>20,252</td>
<td>23,199</td>
</tr>
</tbody>
</table>

5 “The region” includes Albania (AL), Bosnia and Herzegovina (BA), Bulgaria (BG), Croatia (HR), Greece (GR), Hungary (HU), Former Yugoslav Republic of Macedonia (MK), Montenegro (ME), Romania (RO) and Serbia (RS).


7 A recent example from the region is the Sostanj coal-fired TPP in Slovenia. The initial investment cost estimate was EUR 700 million for a gross 600 MW coal plant (net output 545 MW), and the final investment cost was EUR 1,400 million, equal to EUR 2,500/kW. Source: Balkan Energy News, June 2015.
VI. Sensitivity assessment
The results obtained from the modelling are sensitive to the various assumptions used. In this section we analyse the impact of weather conditions on hydro generation and the impact of CO₂ prices on the regional generation mix.

Hydro availability

Hydropower plays an important role in the region, with high shares of hydro capacity present in almost all of the assessed countries. Albania has the greatest share, relying almost exclusively on hydropower, but the share of hydro generation capacity is also high in Montenegro, at currently over 75 percent. This poses a challenge, as in dry years electricity imports can increase rapidly. As this also raises security of supply concerns for the country, this aspect needs to be assessed in greater depth. It should be emphasised that this is another reason why most SEE countries are cautious about further increasing their share of hydro capacities, as to do so would be to deepen their exposure to meteorological conditions (i.e. to the quantity and seasonality of precipitation).

In order to investigate this issue, a sensitivity assessment was carried out that assumed lower precipitation levels than in the previous three scenarios. In the REF, CPP and AMB scenarios, hydro utilisation rates are modelled on the average level over the past eight years, while in the sensitivity runs we checked these scenarios using the lowest utilisation rate during the past eight years, mimicking the situation in a dry year. As droughts usually occur in the same years throughout the region, we modelled the sensitivity runs accordingly: all neighbouring countries experience a lower level of precipitation. This is an important assumption, since drought affects these countries in a similar way and drives import and export prices upwards in a similar pattern.

We focus on two aspects in this sensitivity assessment: the substitution possibilities within the country to compensate for the loss in hydro generation; and the impacts on the export-import positions. Figure 13 illustrates the substitution effects in the case of lower than usual hydro generation.

As shown in Figure 13, the loss in hydro generation is mainly substituted by imports in the first years. In most scenarios, coal- and lignite-based generation contribute from 2025 onwards. While this is accompanied by a lim-

Figure 13 Change in the regional generation mix in the case of low hydro availability
limited amount of gas-based generation in 2015 (originating from the former Yugoslav Republic of Macedonia), from 2020 onwards new fossil-based capacities gradually increase in Serbia and Bosnia and Herzegovina and take on a complementary role alongside imports. In 2030, in the REF and CPP scenarios, Serbia even has sufficient extra fossil-based capacities to export.

Figures 14 to 17 show the disaggregation of the regional generation mix and the change in import position in the five countries in the case of low hydro availability (in 2015, 2020, 2025 and 2030).

The overall conclusion to be drawn from the sensitivity assessment is that security of supply concerns due to exposure to higher levels of hydro generation are well founded. Two-thirds of hydro production in Albania are lost in the case of low hydro availability (2015). However, due to the high level of interconnectedness in the SEE region, there is no shortage of capacities to satisfy the overall regional demand, even in a dry year, if the planned capacities included in the scenarios are built. The market operating model of the Nordic countries could also serve for this region. In the event of favourable hydrological conditions, the region could sell hydro-based electricity to its neighbours, while in dry years the region would increase its imports. This market model would also make it possible to build more hydro capacities in the region without causing extra expense to consumers, and would also reduce security of supply concerns. The high (and increasing) interconnection rates in the region would allow for such cooperation, and countries would be in a win-win situation. In this case, the region would not be disadvantaged by a more stringent European climate and renewable policy, as it would create greater demand for their expanding hydro capacities.

Figure 18 illustrates the impact of lower hydro generation levels on the region’s CO₂ emissions in the various scenarios and years. While the increase in CO₂ emissions remains marginal in 2015, due to the appearance of fossil fuels in the substitution mix, by 2030 emissions have increased by approximately 10 percent. Again, carbon leakage is prevalent whenever the region imports to substitute for non-realised hydro production.

**CO₂ price**

Finally, we analysed the impact of European CO₂ price assumptions on the regional generation mix. One important issue is the role of gas-based generation in the region. Although many countries plan to build new gas-based CCGTs (Albania, the Former Yugoslav Republic of Macedonia) to complement their hydro and coal-based capacities, the results presented below show the low level of their contribution to the generation mix and their very limited utilisation rate in the assumed economic environment. This is due to the relatively higher gas price in the region and the lower European carbon value assumed. In addition, there is still a lack of infrastructure for bringing sufficient and competitively priced gas to many countries in the region. This issue is assessed in detail below.

**CO₂ price effect in 2020**

In the REF scenario (Figure 19), the assumption is that the countries of the region do not impose a carbon price on their electricity producers, and as such they have a competitive advantage over the European power plants that have to pay the price of carbon according to their emissions. An increase in the European carbon price has the following impacts on the regional production mix and, as a result, on regional CO₂ emissions:

- an increase up to EUR 5/t means an increase in emissions due to the reduction in imports and hence the increasing carbon leakage;
- a stable mix in production if the European carbon price is between EUR 5 and EUR 25; and
- from EUR 30/t, natural gas–based production becomes competitive on the European market due to the high enough margin between the regional carbon prices (assumed to be zero in 2020) and an EU carbon price of EUR 30/t): all gas production is exported and coal is already at full capacity.

In the CPP scenario (Figure 20), we assume that the region’s electricity sector faces a carbon price equal to 40 percent of the European carbon price. The impact of the CO₂ price level is similar to the REF scenario, but gas production becomes competitive at a slightly higher carbon price (EUR 30/t).

In the AMB scenario, electricity producers in the region face a European carbon price and thus compete on a level playing field with other European producers. As Figure 21 shows, coal production starts to decrease at a price level of EUR 30/t, and gas-based production becomes profitable at a CO₂ price level of between EUR 40 and EUR 45/t. At this level, shrinking coal production is substituted not only by imports (as at lower carbon prices), but also by regional gas generation.
**Figure 14** Change in generation mix in the case of low hydro availability, 2015

**Figure 15** Change in generation mix in the case of low hydro availability, 2020
**Figure 16** Change in generation mix in the case of low hydro availability, 2025

**Figure 17** Change in generation mix in the case of low hydro availability, 2030
By 2030, regional producers pay the European carbon price in all scenarios (Figures 22–24). The differences between the scenarios are the increasingly lower demand (from the REF to the AMB scenario) and the relative share of fossil fuels versus hydro. The AMB scenario assumes higher hydro capacity expansion than the other two scenarios. Coal-based production decreases gradually and is substituted by imports. This decrease in production becomes more significant at a carbon price of EUR 40/t. Gas-based production is not competitive in the region: its utilisation becomes profitable at high carbon price levels.

The overall conclusion that can be drawn from these figures is the sensitive situation of gas-based generation capacities in the region. The most important drivers for the utilisation of gas-based generation are:

- capacity expansion in coal-based generation;
- capacity expansion in hydro generation;
- infrastructure development in gas networks; and
- carbon pricing in the region and in the EU.

The energy strategies of the countries show that an important decision has to be made in almost all countries in the region as to whether or not they should substitute the currently ageing coal- and lignite-fired generation by new lignite/coal plants, or also plan gas-based CCGTs. Gas-based power plants have lower investment costs but face high risks concerning their profitable utilisation due to uncertainties related to the availability of competitive gas prices in the region. If these gas units do not operate economically, they will constitute sunk investments in the region. This dilemma is further complicated by other factors, such as the long-term prevailing carbon price in the region and potential changes in demand in the future. At higher carbon price levels (e.g. from of EUR 35 to EUR 40), gas could gain a significant role in the region, thus reducing carbon emissions, and countries would avoid lock-in to expensive and carbon-intensive coal- and lignite-based generation.
**Figure 19** Regional generation mix with different CO₂ prices in the REF scenario, 2020

**Figure 20** Regional generation mix with different CO₂ prices in the CPP scenario, 2020
Figure 21 Regional generation mix with different CO$_2$ prices in the AMB scenario, 2020

Figure 22 Regional generation mix with different CO$_2$ prices in the REF scenario, 2030
**Figure 23** Regional generation mix with different CO\textsubscript{2} prices in the CPP scenario, 2030

**Figure 24** Regional generation mix with different CO\textsubscript{2} prices in the AMB scenario, 2030
VII. Network impacts
The electricity transmission system in SEE today is relatively well developed for the current level of power exchange in the region. However, exchange possibilities in the region are limited by bottlenecks in both internal networks and interconnections. Improving the balance between energy supply and demand is crucial in order to boost and sustain economic development in SEE. It also means that TSOs should be prepared to support energy trading between their control areas and with their neighbours through the appropriate development of their transmission networks.

This network analysis focuses on the four project countries — Albania, the former Yugoslav Republic of Macedonia, Montenegro and Serbia — although the representative trade flows with neighbouring countries are also included in the assessment (e.g. with Romania and Bulgaria). The main network elements in the region are presented in Figure 25.

Commercial congestion is permanently present in flow directions from Romania to Serbia and from Bulgaria to Serbia, due to the fact that Romania and Bulgaria have a surplus of electrical energy, and that Serbia is used as a transit area towards Montenegro, the former Yugoslav Republic of Macedonia and Greece (countries with an electrical energy deficit).

Prior to October 2004, the SEE power system was not connected for unified parallel operation. Following reconnection with the first synchronous zone of the Union for the Coordination of Transmission of Electricity (UCTE) in October 2004, power system conditions in SEE changed dramatically. Power utilities in the region began a process of deregulation and privatisation. Due to the post-socialist collapse in industrial consumption, the SEE region was initially characterised by a surplus of installed generation capacity. Relatively cheap electricity from SEE became

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**Figure 25** Geographical coverage of the network analysis
a great market opportunity. Countries in the region agreed to create a stable common regulatory and market framework capable of attracting investment in power generation and transmission networks.

All these factors have a substantial impact on the operation and development of the regional transmission network. Compared to other European regions, SEE is characterised by large interconnection capacities at a 220 kV voltage level and above.

**Planned new network elements**

There are comprehensive, realistic plans for the development of the transmission network in SEE, and current practice suggests that these development plans are more or less being implemented. Aside from the fact that the countries of the region can be regarded as well connected, new investments are expected, especially in cross-border elements or internal connections that will have a significant impact on cross-border capacities.

The planned new transmission lines, listed in accordance with the ENTSO-E Ten-Year Network Development Plan (TYNDP) and strategic development and investment projects in each country, are shown in Figure 26.

In the three SLED scenarios (REF, CPP and AMB), generation capacities — both distributed RES generation and conventional generation — and the assumed total electricity consumption change according to the agreed scenario definitions. The introduction of these changes in the network model has many impacts, which are assessed under the following categories:

- steady-state and contingency analyses;
- evaluation of NTC; and
- calculation of transmission grid losses.

The detailed network modelling methodology for these three areas is presented in the Annex following the network modelling description.

**Results of network modelling**

The winter and summer operating regimes for the 2015, 2020 and 2025 development stage in all scenarios were assessed in the network modelling. The year
2015 was considered as the reference year in the assessment, reflecting the present network topology and the currently available generation capacities.

**Steady-state and contingency analyses**

Calculations within system studies were conducted on regional network models for SEE prepared for 2020 and 2025. The power systems of the four assessed countries were modelled according to the data collected and the Southeast Europe Cooperation Initiative (SECI) regional model for 2020/2025, the available respective national development plans, and the transmission system development set in the ENTSO-E TYNDP for 2012–2022.

**System balances**

Power system balances (in MW) in the assessed countries, analysed for all regimes (winter and summer) and scenarios, are presented below.

In 2020:
- Montenegro is an importing country in the summer regime, while in the winter regime it is an exporting country due to the significant number of RES.
- Serbia is an exporter of 1,000 MW in both regimes.
- Albania is an exporting country.

Due to new capacities (conventional, especially TPPs), in 2025:
- Serbia becomes a large exporter.
- Montenegro is an exporter in the winter peak regime (due to a certain number of RES), but in the summer peak regime it still imports a small amount of power.
- Albania only exports in the winter peak regime (AMB and REF) at 150 MW, but in other regimes it is balanced.

The former Yugoslav Republic of Macedonia is an importer in all regimes and scenarios.

**(N-1) Security criteria**

In 2015, there are no high-loaded elements at the 220 kV and 400 kV voltage levels in the assessed countries.

The results of the security assessments for 2020 and 2025 are shown in Tables 10 and 11 for the whole of the assessed region, as contingencies appear at regional but not at country level.

In 2020, the following strengthening is necessary:

- In all scenarios, the tripping of the OHL 220 kV Fierza (AL)-Titan (AL) line leads to the overloading of the OHL 220 kV VauDejes (AL)-Komani (AL) line. The new OHL 220 kV Komani (AL)-Titan (AL) line solves the problem (70 km).
- Some windfarms that are to be constructed within the Serbian power utility EPS will be connected to the OHL 220 kV Zrenjanin (RS)-Pancevo (RS) line. As a consequence of overloading in that area, in the CPP scenario the conductor on the OHL 220 kV Pancevo (RS)-Zrenjanin (RS) line should be replaced with a higher capacity one (length of approximately 22+44 km).
- In the AMB scenario, only the replacement of a 1 km length of conductor on the OHL 220 kV HIP (RS)-Pancevo (RS) line is required (in addition to the OHL 220 kV VauDejes [AL]-Komani [AL] line).

Generally speaking, the CPP scenario requires more additional investments than the other two (as a consequence of more new elements). The REF and AMB scenarios require the same level of investment, but less than the CPP scenario.

In 2025, the following strengthening is necessary:

- In all scenarios, the tripping of the line OHL 220 kV Fierza (AL)-Titan (AL) leads to the overloading of the OHL 220 kV VauDejes (AL)-Komani (AL) line. The new OHL 220 kV Komani (AL)-Titan (AL) line solves that problem (70 km).
- Some windfarms to be constructed within the Serbian EPS will be connected to the OHL 220 kV Zrenjanin (RS)-Pancevo (RS) line. As a consequence of overloading in that area, in the CPP and AMB scenarios the conductor on the OHL 220 kV HIP (RS)-Beograd 8 (RS) line should be replaced with a higher-capacity one (length of approximately 14.5 km).

The REF scenario requires less additional investment than the other two (as a consequence of fewer new elements). The CPP and AMB scenarios require the same level of investment.

We can conclude from the results that the connection of the new RES causes some new overloading in Serbia and Albania, while in Montenegro and the former Yugoslav Republic of Macedonia RES capacity development has no impact on the 400 kV and
220 kV transmission network. Thus, for Montenegro and the former Yugoslav Republic of Macedonia, the newly installed RES generation capacities assumed in the scenarios do not pose problems to the electricity network. The present system with the planned line extensions could cope with the modelled electricity flows.

**Net transfer capacity**

According to the ENTSO-E methodology, the results of the gross transfer capacity (GTC) calculation should be used for market analysis. However, since in the current operation of the power systems NTC values are used to describe limitations in transfer capacities between countries, NTCs were calculated on the borders of the analysed countries. These capacities were used as inputs in the market analysis.

Capacity calculation is always related to a given power system scenario — that is, generation schedule and pattern, consumption pattern and available network state. These constitute the data that make it possible to build up a mathematical model of the power system (load-flow equations). The solution of this model provides knowledge of the voltages in the network nodes and the power flows in the network elements, which are the parameters monitored by a TSO in order to assess system security.

Before the results are presented, it is important to underline that NTC values, beside network topologies, depend on the generation pattern of the region, as

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**Table 10 Contingencies in 2020**

<table>
<thead>
<tr>
<th>Scenario 2020</th>
<th>Tripping</th>
<th>Overloading</th>
<th>Solution</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>REF</strong></td>
<td>Winter max</td>
<td>OHL 220 kV Fierza (AL) – Titan (AL)</td>
<td>OHL 220 kV VauDejes (AL) – Komani (AL)</td>
</tr>
<tr>
<td></td>
<td>Summer max</td>
<td>OHL 220 kV Zrenjanin (RS) – WPP (RS)</td>
<td>OHL 220 kV HIP (RS) – Beograd8 (RS)</td>
</tr>
<tr>
<td><strong>CPP</strong></td>
<td>Winter max</td>
<td>OHL 220 kV Komani (AL) – Kolace (AL)</td>
<td>OHL 220 kV VauDejes (AL) – Komani (AL)</td>
</tr>
<tr>
<td></td>
<td>Summer max</td>
<td>OHL 400 kV Dumno (RS) – Smederevo (RS)</td>
<td>OHL 220 kV WPPs (RS) – Zrenjanin (RS)</td>
</tr>
<tr>
<td><strong>AMB</strong></td>
<td>Winter max</td>
<td>OHL 220 kV Komani (AL) – Kolace (AL)</td>
<td>OHL 220 kV VauDejes (AL) – Komani (AL)</td>
</tr>
<tr>
<td></td>
<td>Summer max</td>
<td>OHL 220 kV WPPs (RS) – Pancevo (RS)</td>
<td>OHL 220 kV WPPs (RS) – Zrenjanin (RS)</td>
</tr>
</tbody>
</table>
The NTC values for the three assessed scenarios for 2020 and 2025 are presented in Figures 27 to 30.

The NTC values for the AMB and CPP scenarios are higher than for the REF scenario on most of the borders in both the winter and summer regimes. In the winter regime, in the AMB and CPP scenarios the NTC does not increase in the direction Serbia–Former Yugoslav Republic of Macedonia compared to the REF scenario. Also, in the summer regime the same is true in terms of the direction Former Yugoslav Republic of Macedonia–Serbia. These values are already sufficiently high for all scenarios, and this variation is the effect of internal overloading within the Serbian system. The AMB and CPP scenarios show the same results in terms of NTC as the REF scenario in the direction Albania–Former Yugoslav Republic of Macedonia in the winter regime.

The overall conclusion for 2020 is that replacing conventional sources with RES increases NTC values on most borders, with the exception of the two mentioned cases for the winter regime in the direction Serbia–Former Yugoslav Republic of Macedonia, and for the summer regime in the direction Former Yugoslav Republic of Macedonia–Serbia.

In the winter regime, the greatest increase is in the direction Former Yugoslav Republic of Macedonia–Serbia, and in the summer regime in the direction Serbia–Montenegro.

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**Table 11 Contingencies in 2025**

<table>
<thead>
<tr>
<th>Scenario 2025</th>
<th>Tripping</th>
<th>Overloading</th>
<th>Solution</th>
</tr>
</thead>
<tbody>
<tr>
<td>REF Winter max</td>
<td>OHL 220 kV Fiera (AL)–Titan (AL)</td>
<td>OHL 220 kV VauDejes (AL)–Komani (AL)</td>
<td>New OHL 220 kV Komani (AL)–Titan (AL)</td>
</tr>
<tr>
<td>Summer max</td>
<td>OHL 220 kV WPPs (RS)–Zrenjanin (RS)</td>
<td>OHL 220 kV HIP (RS)–Beograd8 (RS)</td>
<td>Changing of the conductors (on OHL 220 kV HIP–BG8) and earth wires and OPGW across the Danube River with higher capacity (1 km)</td>
</tr>
<tr>
<td></td>
<td>OHL 400 kV Drmno (RS)–Smederevo (RS)</td>
<td>OHL 400 kV Pancrevo (RS)–Beograd (RS)</td>
<td>Changing of the conductors and earth wires and OPGW across the Danube River with higher capacity (1 km)</td>
</tr>
<tr>
<td>CPP Winter max</td>
<td>OHL 220 kV Komani (AL)–Kolace (AL)</td>
<td>OHL 220 kV VauDejes (AL)–Komani (AL)</td>
<td>New OHL 220 kV Komani (AL)–Titan (AL)</td>
</tr>
<tr>
<td>Summer max</td>
<td>OHL 220 kV Pancrevo (RS)–Beograd20 (RS)</td>
<td>OHL 220 kV HIP (RS)–Beograd8 (RS)</td>
<td>Changing of the conductors (on OHL 220 kV HIP–BG8) and earth wires and OPGW with higher capacity (whole line 14.5 km)</td>
</tr>
<tr>
<td></td>
<td>OHL 220 kV WPPs (RS)–Zrenjanin (RS)</td>
<td>OHL 400 kV Pancevo (RS)–Beograd20 (RS)</td>
<td>Changing of the conductors (on OHL 220 kV HIP–BG8) and earth wires and OPGW with higher capacity (whole line 14.5 km)</td>
</tr>
<tr>
<td>AMB Winter max</td>
<td>OHL 220 kV Komani (AL)–Kolace (AL)</td>
<td>OHL 220 kV VauDejes (AL)–Komani (AL)</td>
<td>New OHL 220 kV Komani (AL)–Titan (AL)</td>
</tr>
<tr>
<td>Summer max</td>
<td>OHL 220 kV Pancrevo (RS)–Beograd20 (RS)</td>
<td>OHL 220 kV HIP (RS)–Beograd8 (RS)</td>
<td>Changing of the conductors (on OHL 220 kV HIP–BG8) and earth wires and OPGW with higher capacity (whole line 14.5 km)</td>
</tr>
<tr>
<td></td>
<td>OHL 220 kV WPPs (RS)–Zrenjanin (RS)</td>
<td>OHL 220 kV HIP (RS)–Beograd8 (RS)</td>
<td>Changing of the conductors (on OHL 220 kV HIP–BG8) and earth wires and OPGW with higher capacity (whole line 14.5 km)</td>
</tr>
</tbody>
</table>

In 2025, the implementation of RES increases NTC values on most borders in both the winter and summer regimes. In the case of the Montenegro–Albania and Albania–Former Yugoslav Republic of Macedonia directions there is a decrease in NTC values in the AMB and CPP scenarios compared to the REF scenario in both the winter and summer regimes. In both regimes, the greatest increase is in the directions Serbia–Montenegro and Serbia–Albania.

Transmission grid losses

Transmission losses were calculated for all four analysed countries. The analyses were carried out for three scenarios with different levels of RES, two regimes (winter maximum and summer maximum) and three target years (2015, 2020 and 2025) (Tables 12–14). The losses are highly dependent on electricity exchanges, transmission reinforcements, levels of production and consumption, as well as the connection points of power plants and consumers. In all countries, power losses are higher in the winter regime and lower in the summer regime due to the large exchanges between the countries during the winter regime. Total yearly transmission losses range between 96.3 and 1,031 GWh, depending on the country, scenario and year. The greatest losses in total consumption are expected in Montenegro in the AMB scenario for 2020 (summer regime), at 5.3 percent. The lowest share (1.3 percent) is expected in the former Yugoslav Republic of Macedonia in the REF scenario for 2025 (summer regime). In the former Yugoslav Republic of Macedonia, despite the higher level of RES penetration, yearly transmission losses
are pretty much the same throughout the analysed period (2015–2025) in all the scenarios.

Greater differences in transmission losses between the scenarios are expected in 2025 in all the countries except the former Yugoslav Republic of Macedonia. In this context, from the REF to the AMB scenario in Serbia losses tend to become smaller, compared to the highest losses of 1,030.5 GWh in the REF scenario. Likewise, in Montenegro, losses reach the highest level (197.2 GWh) in the REF scenario and the lowest (169.8 GWh) in the AMB scenario. In Albania, in all three scenarios, losses are approximately at the same level during 2020. Going further to 2025, in the REF and AMB scenarios losses are similar, while in the CPP scenario they reach a maximum value of 332.3 GWh.

In summary, the increase in RES in overall installed capacities, presented through the three scenarios, will produce a higher level of transmission losses in gross consumption only in the case of Montenegro in 2020. Other countries will not be significantly affected.

Figure 29 Net transfer capacity values for 2025 (winter regime)

![Figure 29 Net transfer capacity values for 2025 (winter regime)](image)

Figure 30 Net transfer capacity values for 2025 (summer regime)

![Figure 30 Net transfer capacity values for 2025 (summer regime)](image)
### Table 12 Transmission losses in 2015 for all countries, scenarios and regimes

<table>
<thead>
<tr>
<th>Yearly transmission losses (GWh)</th>
<th>2015</th>
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<tbody>
<tr>
<td>Serbia</td>
<td>Winter</td>
<td>912.7</td>
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<tr>
<td>Former Yugoslav Republic of Macedonia</td>
<td>Winter</td>
<td>126.9</td>
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<tr>
<td>Montenegro</td>
<td>Winter</td>
<td>96.3</td>
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</tr>
<tr>
<td>Albania</td>
<td>Winter</td>
<td>164.7</td>
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<tr>
<td><strong>REF scenario</strong></td>
<td>Summer</td>
<td>146.8</td>
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<tr>
<td><strong>CPP scenario</strong></td>
<td>Winter</td>
<td>903.8</td>
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<tr>
<td><strong>AMB scenario</strong></td>
<td>Winter</td>
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</tbody>
</table>

### Table 13 Transmission losses in 2020 for all countries, scenarios and regimes

<table>
<thead>
<tr>
<th>Yearly transmission losses (GWh)</th>
<th>2020</th>
<th></th>
<th></th>
<th></th>
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</thead>
<tbody>
<tr>
<td>Serbia</td>
<td>Winter</td>
<td>954.4</td>
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<td></td>
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<td></td>
</tr>
<tr>
<td>Former Yugoslav Republic of Macedonia</td>
<td>Winter</td>
<td>146.8</td>
<td></td>
<td></td>
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<tr>
<td>Montenegro</td>
<td>Winter</td>
<td>204.3</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Albania</td>
<td>Winter</td>
<td>252.3</td>
<td></td>
<td></td>
<td></td>
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<td></td>
</tr>
<tr>
<td><strong>REF scenario</strong></td>
<td>Summer</td>
<td>145.9</td>
<td></td>
<td></td>
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<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>CPP scenario</strong></td>
<td>Winter</td>
<td>982.2</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>AMB scenario</strong></td>
<td>Winter</td>
<td>963.4</td>
<td></td>
<td></td>
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</table>

### Table 14 Transmission losses in 2025 for all countries, scenarios and regimes

<table>
<thead>
<tr>
<th>Yearly transmission losses (GWh)</th>
<th>2025</th>
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<tr>
<td>Serbia</td>
<td>Winter</td>
<td>1,030.5</td>
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<tr>
<td>Former Yugoslav Republic of Macedonia</td>
<td>Winter</td>
<td>134.9</td>
<td></td>
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<td></td>
</tr>
<tr>
<td>Montenegro</td>
<td>Winter</td>
<td>197.2</td>
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<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Albania</td>
<td>Winter</td>
<td>264.9</td>
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<td><strong>REF scenario</strong></td>
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<tr>
<td><strong>CPP scenario</strong></td>
<td>Winter</td>
<td>982.2</td>
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<tr>
<td><strong>AMB scenario</strong></td>
<td>Winter</td>
<td>963.4</td>
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<td></td>
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</tbody>
</table>
VIII. Annex
The two applied models — the EEMM and the EKC network model — are described in greater detail in this annex.

The European Electricity Market Model
The EEMM simulates the operation of a European electricity wholesale market. It is a partial equilibrium model.

Geographical scope
Figure 31 shows the geographical coverage of the model. In the countries coloured orange, electricity prices are derived from the demand–supply balance. In the other group of countries, shown in blue, prices are exogenous.

Market participants
There are three types of market participant in the model: producers, consumers and traders. Markets are assumed to be perfectly competitive — that is, actors are price takers.

Producers are the owners and operators of power plants. Each plant has a specific marginal cost of production, which is constant at the unit level, and generation is capacity constrained at the level of installed capacity.

The EEMM works with power plants at the unit level, and there are close to 5,000 power plant units in the model. For individual power plants, the following essential information is contained by the model: installed capacity, year of construction, technology and main fuel type.

Within the electricity sector we can distinguish 12 different technologies: biomass-fired power plants; coal-fired plants; lignite-fired plants; geothermal plants; heavy fuel oil–fired plants; light fuel oil–fired plants; hydropower plants; wind power plants; solar power plants; nuclear plants; natural gas–fired plants; and tidal power plants.

The model takes into account short-term variable costs with the following four main components: fuel costs; variable OPEX; excise tax; and CO₂ costs (where applicable). The fuel cost in each generation unit depends on the type and price of fuel and the overall efficiency of electricity generation. The latter is taken

Figure 31 Analysed countries
from the literature and empirical observation for various power plant types and commissioning dates. When the market price is above the marginal generation cost of a unit, the unit is operated at full available capacity, and if the price is below the marginal cost there is no production.

Consumers are represented in the model in an aggregated way by price-sensitive demand curves. The slope of the demand curve is the same for all countries. When determining future consumption we consider the relationship between past GDP and electricity consumption figures separately for each country. Based on this relation and the GDP forecast we establish the expected annual electricity consumption.

Finally, traders connect the production and consumption sides of a market, export electricity to more expensive countries and import it from cheaper ones. Within the model, a country appears as a node — that is, there are no network constraints within the country, only between countries. Cross-border trade takes place on capacity-constrained interconnectors between neighbouring countries. Electricity exchanges occur until either prices, net of direct transmission costs or export tariffs, equalise across the markets; or the transmission capacity of the interconnector is reached.

Equilibrium

The model is a partial equilibrium model and calculates the equilibrium allocation in all domestic electricity markets under the following constraints:

- Producers maximise their short-term profits, given market prices.
- Total domestic consumption is given by the aggregate electricity demand function in each country.
- Electricity transactions (export and import) occur between neighbouring countries until market prices are equalised or transmission capacity is exhausted.
- Energy produced and imported is in balance with energy consumed and exported.

Market equilibrium always exists and is unique in the model.

The calculated market equilibrium is static: it only describes situations with the same demand, supply and transmission characteristics. To simulate the price development of more complex electricity products, such as those for base-load or peak-load delivery, we performed several model runs with typical market parameters and took the weighted average of the resulting prices.

When modelling, hourly markets are simulated, and these simulations are independent from one another — that is, ramp-up costs are excluded. Within the model, the equilibrium for a given hour (with respect to quantities and prices) is reached simultaneously by the producer and transmission segments. Figure 32 illustrates the operation of the model.

---

**Figure 32 Operation of the model**

<table>
<thead>
<tr>
<th>Input</th>
<th>Output</th>
</tr>
</thead>
<tbody>
<tr>
<td>Marginal generation cost</td>
<td>Equilibrium prices by country</td>
</tr>
<tr>
<td>Available generation capacity</td>
<td>Electricity trade between countries</td>
</tr>
<tr>
<td>Cross-border transmission capacity</td>
<td>Production by plant</td>
</tr>
<tr>
<td>Demand curves by country</td>
<td>Supply curves by country</td>
</tr>
<tr>
<td>Model</td>
<td></td>
</tr>
</tbody>
</table>
By determining the short-run marginal cost and available capacity for each power plant we can construct the supply curve for each country — in other words, the merit order curve. Taking into consideration the constraints of cross-border capacities and the demand curves characterising each country, we arrive at the input parameters of the model. The model applies these data to maximise European welfare, which is the sum of producer and consumer surpluses. As a result of model computations we get the hourly equilibrium price for each country, the hourly commercial transfers between the countries, and the production of each power plant unit.

We simulate the short-term market represented by a selected hour. We typically aim to model an annual period, rather than a single hour, therefore on the demand side it is necessary to settle on a given number of reference hours through which annual average prices are approximated. In the model, 90 reference hours are established.

**Network representation**

The EEMM assumes that each country is a node — in other words, network constraints do not exist within any of the countries. Cross-border capacities, on the other hand, may impose a serious limitation on the trading of electricity. Scarcity is expressed through the NTC.

The EKC model provides modelled NTC values for the four target countries of the SLED project and the neighbouring region (directly connected to the target countries), while for the rest of the countries modelled by the EEMM, data from ENTSO-E are used.

**The EKC network model**

A regional load-flow model on which analyses are performed was developed based on SECI regional transmission models for 2015 (also used as the current model), 2020 and 2025, updated according to the assumptions of the ToR.

All analyses were performed for the years 2015, 2020 and 2025, for two typical regimes: winter peak (third Wednesday in January at 19:30), and summer peak (third Wednesday in July at 10:30).

The topology of the transmission networks in SEE countries (Albania, Bosnia and Herzegovina, Bulgaria, Croatia, Greece, the former Yugoslav Republic of Macedonia, Romania and Serbia) is taken according to the SECI regional model, updated according to generation surplus projections in the SEE region. Other neighbouring countries (France, Switzerland, Germany, Ukraine and Slovakia) are modelled as injections (over interconnection lines); while Austria and Hungary are presented with the full model adopted according to the UCTE system adequacy forecast 2014–2024.

The system study was performed on already existing studies using the current regional system models developed under SECI, checked and updated by the TSOs. System studies and planning are done on a regional basis, as is the definition of the border crossing points.

Electric power systems in SEE were modelled with their complete transmission networks (at 400 kV, 220 kV and 150 kV). The power systems of the four assessed countries were modelled in addition at the 110 kV voltage level. The network equivalent of Turkey (i.e. European part) and the rest of ENTSO-E Continental Europe (modelled over the X-node injections) were also used in the model.

The following assessment was carried out in the network study:

- Load-flow data collection, which includes:
  - an assessment of the existing electricity network situation in Albania, the former Yugoslav Republic of Macedonia, Montenegro and Serbia, together with the regional context; and
  - a definition of the network topologies and regimes for 2015, 2020 and 2025, using realistic scenarios for demand growth, generation expansion, transit flows, RES integration and HVDC links.

- TTC/NTC evaluation among Albania, the former Yugoslav Republic of Macedonia, Montenegro and Serbia in all directions, for all topology scenarios, with reference to each target year and regime.

- An assessment of transmission grid losses with and without a level of energy production from RES.

**Load-flow data collection**

In the process of collecting the data needed for load-flow studies, representatives of the four countries reviewed and updated the proposed datasets, which include:
Demand level in the agreed regimes and power exchanges in 2015, 2020 and 2025 for two characteristic regimes:

- third Wednesday in January at 19:30 (winter peak); and
- third Wednesday in July at 10:30 (summer peak).

A list of new generation facilities and generation units to be decommissioned up to 2015, 2020 and 2025.

A list of new elements in the transmission network.

The level of transmission reliability margin used in the evaluation of the NTC.

These data were used for the preparation of the network models for 2015, 2025 and 2025, which were used for the load-flow analyses.

**Demand**

The development of demand in two characteristic regimes (third Wednesday in January at 19:30 [winter peak] and third Wednesday in July at 10:30 [summer peak] in 2015, 2020 and 2025 was analysed on the basis of:

- ENTSO-E online datasets;
- ENTSO-E scenario outlook and adequacy forecasts;
- national demand projections; and
- consultants’ datasets from relevant projects in the SEE region.

Since network forecast models are used in our analysis, demand excludes transmission and distribution losses, as well as the power plants’ own consumption and pumping.

**Network modelling methodology**

The network modelling methodology comprises three parts:

- steady-state and contingency analyses;
- evaluation of the NTC; and
- calculation of transmission grid losses.

These parts are introduced in detail below.

**Steady-state and contingency analyses**

For the defined scenarios, steady-state load flows were calculated and contingency (n-1) analyses performed. Security criteria were based on the loadings of lines and voltage profile, and checked for each scenario analysed.

Load-flow analyses provide an insight into transmission network adequacy for the observed scenarios of exchanges and a comparison of observed configurations, under steady-state and (n-1) operating conditions.

Load-flow assessment is a basic step in NTC evaluation and comprises the following analyses:

- steady-state AC load flow;
- security (n-1) assessment; and
- voltage profile analysis.

In the analysis of voltage profiles, voltage limits are taken according to the respective national grid codes.

It should be stressed that only 400 kV and 220 kV networks were assessed from a security point of view. There are many new RES to be connected to lower-voltage networks, which might cause problems in networks of 110 kV or lower, although this should be solved via the national transmission network plans.

**Evaluation of net transfer capacity**

Total and net transfer capacity (TTC/NTC) were evaluated between Albania, the former Yugoslav Republic of Macedonia, Montenegro and Serbia, as well as between these countries and their neighbours, in all directions, for all topology scenarios, with reference to each target year and regime. A final assessment was also made of the TTC/NTC additional values as a result of new interconnections and the strengthening of the major energy transit routes.

It is important to note that the TTC, NTC, base case exchange (BCE), already allocated capacity (AAC) and available transfer capacity (ATC) are the exchange programme values; these are not the physical flows and generally differ from the physical flows at the interconnection lines (except in particular cases of radial operation).

The solution of this model is the so-called base case and is the starting point for the computation. This base case can already contain exchange programmes between TSOs and control areas. These are the various transactions likely to exist in the forecasted situation according to what has been observed in the past.
The TTC value may therefore vary (increase or decrease) when approaching the time of programme execution as a result of a more accurate knowledge of generating unit schedules, load pattern, network topology and tie line availability.

General definitions of transfer capacities (TTC, NTC) and the procedures for their assessment are according to ENTSO-E and the practice and experience of regional SEE TSO working groups.

**BASE CASE EXCHANGE**
In the base case, for a given pair of neighbouring control areas A and B, for which capacities are to be computed, a global exchange programme known as BCE exists. The BCEs are the programme (contractual) values related to the base case model.

**MAXIMUM ADDITIONAL EXCHANGE**
The maximum additional programme exchange (over the BCE) that meets security standards is indicated by $\Delta E_{\text{max}}$. An additional programme exchange is performed by decreasing generation in area A, and simultaneously increasing generation in area B.

**TOTAL TRANSFER CAPACITY**
The TTC is the maximum exchange programme between two areas, compatible with the operational security standards applicable to each system, if future network conditions, generation and load patterns are perfectly known in advance.

$$\text{TTC} = \text{BCE} + \Delta E_{\text{max}}$$

**TRANSMISSION RELIABILITY MARGIN**
The TRM is a security margin that deals with uncertainties in the computed TTC values arising from:
- unintended deviations in physical flows during operation due to the physical functioning of load frequency control (LFC);
- emergency exchanges between TSOs to deal with unexpected unbalanced situations in real time; and
- inaccuracies, for example in data collection and measurements.

In the present study, the TRM value used is according to the collected load-flow data sent by the TSOs.

**NET TRANSFER CAPACITY**
The NTC is the maximum exchange programme between two areas compatible with the security standards applicable in both areas, taking into account the technical uncertainties in future network conditions.

$$\text{NTC} = \text{TTC} - \text{TRM}$$

**Transmission grid losses**
The assessment of electricity losses is based on the equivalent duration time of losses in winter peak and summer peak periods. This approach takes into account that the impact on losses can be different in these two regimes, meaning that annual losses can be determined more accurately.

The assessment of electricity losses is based on the equivalent duration time of maximum losses. The method used to determine this equivalent duration time requires two parameters as input: maximum demand and load factor. These two parameters are obtained from an analysis of the load duration diagram of the analysed year for the respective power system.

Yearly losses are calculated based on grid losses in MW calculated for the two analysed regimes — winter peak and summer peak — and the equivalent load duration time of the respective loads in these regimes. With the calculated equivalent duration time of maximum losses for the respective period, yearly transmission grid losses (GWh) are calculated by multiplying this value by power losses (MW):

$$P_{\text{loss}} = \frac{W_{\text{loss}}}{1000} \times T_{\text{eq}}$$

$T_{\text{eq}}$ - Equivalent duration time in hours for the respective load in regime $i$

$P_{\text{loss}}$ - Active power losses in MW in specific regime $i$

$W_{\text{loss}}$ - Total losses in GWh

$T_{\text{eq}}$ - Equivalent duration time in hours for the respective load in regime $i$

$W_{\text{peak}}$ - Total losses in winter peak

$W_{\text{peak}}$ - Total losses in summer peak

$\text{NTC} = \text{TTC} - \text{TRM}$

(N-1) Security criteria refer to the assessment of the electricity system when the largest-capacity (either network or generation) is removed from the system to simulate the state of the system with the outage of the largest capacity element. In this case, an outage of a network element is modelled.

**Transmission grid losses**
The assessment of electricity losses is based on the equivalent duration time of losses in winter peak and summer peak periods. This approach takes into account that the impact on losses can be different in these two regimes, meaning that annual losses can be determined more accurately.

The assessment of electricity losses is based on the equivalent duration time of maximum losses. The method used to determine this equivalent duration time requires two parameters as input: maximum demand and load factor. These two parameters are obtained from an analysis of the load duration diagram of the analysed year for the respective power system.

Yearly losses are calculated based on grid losses in MW calculated for the two analysed regimes — winter peak and summer peak — and the equivalent load duration time of the respective loads in these regimes. With the calculated equivalent duration time of maximum losses for the respective period, yearly transmission grid losses (GWh) are calculated by multiplying this value by power losses (MW):

$$W_{\text{loss}} = W_{\text{peak}}^{\text{peak}} + W_{\text{peak}}^{\text{peak}} \ [\text{GWh}]$$

$$W_{\text{loss}} = P_{\text{loss}}^{\text{peak}} \times T_{\text{eq}}^{\text{peak}} \ [\text{GWh}]$$

$P_{\text{loss}}^{\text{peak}}$ - Active power losses in MW in specific regime $i$

$T_{\text{eq}}^{\text{peak}}$ - Equivalent duration time in hours for the respective load in regime $i$
Decarbonisation modelling in the electricity sector

Regional Report

Support for Low-Emission Development in South Eastern Europe (SLED)