SEERMAP

South East Europe Electricity Roadmap

SOUTH EAST EUROPE ELECTRICITY ROADMAP

# Country report
# Serbia

**SEERMAP: South East Europe Electricity Roadmap**
**Country report: Serbia 2017**

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The South East Europe Electricity Roadmap (SEERMAP) project develops electricity sector scenarios until 2050. The project focuses on 9 countries in South East Europe: Albania, Bosnia and Herzegovina, Bulgaria, Greece, Kosovo*, former Yugoslav Republic of Macedonia, Montenegro, Romania and Serbia. The implications of different investment strategies in the electricity sector are assessed for affordability, energy security, sustainability and security of supply. In addition to analytical work, the project focuses on trainings, capacity building and enhancing dialogue and cooperation within the SEE region.

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

Further information about the project is available at: **www.seermap.rekk.hu**

Funding for the project was provided by the Austrian Federal Ministry of Agriculture, Forestry, Environment and Water Management and the European Climate Foundation.

**The project was carried out by a consortium of 5 partners, and involved 9 local partners as subcontractors. The consortium was led by the Regional Centre for Energy Policy Research (REKK).**

The **Regional Centre for Energy Policy Research (REKK)** is a Budapest based think tank, and consortium leader of the SEERMAP project. The aim of REKK is to provide professional analysis and advice on networked energy markets that are both commercially and environmentally sustainable. REKK has performed comprehensive research, consulting and teaching activities in the fields of electricity, gas and carbon-dioxide markets since 2004, with analyses ranging from the impact assessments of regulatory measures to the preparation of individual companies' investment decisions.

The **Energy Economics Group (EEG),** part of the Institute of Energy Systems and Electrical Drives at the Technische Universität Wien (TU Wien), conducts research in the core areas of renewable energy, energy modelling, sustainable energy systems, and energy markets. EEG has managed and carried out many international as well as national research projects funded by the European Commission, national governments, public and private clients in several fields of research, especially focusing on renewable and new energy systems. EEG is based in Vienna and was originally founded as research institute at TU Wien.

The **Electricity Coordination Centre (EKC)** provides a full range of strategic business and technical consultancy and engineering leading models and methodologies in the area of electric power systems, transmission and distribution systems, power generation and electricity markets. EKC was founded in 1993 and provides consultant services from 1997 in the region of South-East Europe, Europe as well as in the regions of Middle East, Eastern Africa and Central Asia. EKC also organises educational and professional trainings.

The work of **OG Research** focuses on macroeconomic research and state of the art macroeconomic modelling, identification of key risks and prediction of macroeconomic variables in emerging and frontier markets, assessment of economic developments, and advice on modern macroeconomic modelling and monetary policy. The company was founded in 2006 and is based in Prague and Budapest.

The **Energy Regulators Regional Association (ERRA)** is a voluntary organisation comprised of independent energy regulatory bodies primarily from Europe, Asia, Africa, the Middle East and the United States of America. There are now 30 full and 6 associate members working together in ERRA. The Association's main objective is to increase exchange of information and experience among its members and to expand access to energy regulatory experience around the world.

**Local partners in SEERMAP target countries**

**RES Foundation (Serbia)** engages, facilitates and empowers efficient networks of relationships among key stakeholders in order to provide public goods and services for resilience. RES stands for public goods, sustainability and participatory policy making with focus on climate change and energy.

**POLIS University (U_Polis, Albania)** is young, yet ambitious institution, quality research-led university, supporting a focused range of core disciplines in the field of architecture, engineering, urban planning, design, environmental management and VET in Energy Efficiency.

**ENOVA (Bosnia and Herzegovina)** is a multi-disciplinary consultancy with more than 15 years of experience in energy, environment and economic development sectors. The organization develops and implements projects and solutions of national and regional importance applying sound knowledge, stakeholder engagement and policy dialogue with the mission to contributing to sustainable development in South East Europe.

The **Center for the Study of Democracy (CSD, Bulgaria)** is a European-based interdisciplinary non-partisan public policy research institute. CSD provides independent research and policy advocacy expertise in analysing regional and European energy policies, energy sector governance and the social and economic implications of major national and international energy projects.

**FACETS (Greece)** specialises in issues of energy, environment and climate, and their complex interdependence and interaction. Founded in 2006, it has carried out a wide range of projects including: environmental impact assessment, emissions trading, sustainability planning at regional/municipal level, assessment of weather and climate-change induced impacts and associated risks, forecasting energy production and demand, and RES and energy conservation development.

**Institute for Development Policy (INDEP, Kosovo*)** is a Prishtina based think tank established in 2011 with the mission of strengthening democratic governance and playing the role of public policy watchdog. INDEP is focused on researching about and providing policy recommendations on sustainable energy options, climate change and environment protection.

**MACEF (Macedonia)** is a multi-disciplinary NGO consultancy, providing intellectual, technical and project management support services in the energy and environmental fields nationally and worldwide. MACEF holds stake in the design of the energy policy and energy sector and energy resources development planning process, in the promotion of scientific achievements on efficient use of resources and develops strategies and implements action plans for EE in the local self-government unit and wider.

**Institute for Entrepreneurship and Economic Development (IPER, Montenegro)** is an economic thing tank with the mission to promote and implement the ideas of free market, entrepreneurship, private property in an open, responsible and democratic society in accordance with the rule of law in Montenegro. Core policy areas of IPER's research work include: Regional Policy and Regional Development, Social Policy, Economic Reforms, Business Environment and Job Creation and Energy Sector.

The **Energy Policy Group (EPG, Romania)** is a Bucharest-based independent, non-profit think-tank grounded in 2014, specializing in energy policy, markets, and strategy. EPG seeks to facilitate an informed dialogue between decision-makers, energy companies, and the broader public on the economic, social, and environmental impact of energy policies and regulations, as well as energy significant projects. To this purpose, EPG partners with reputed think-tanks, academic institutions, energy companies, and media platforms.

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# 1 | Executive summary

South East Europe is a diverse region with respect to energy policy and legislation, with a mix of EU member states, candidate and potential candidate countries. Despite this diversity, shared challenges and opportunities exist among the countries of the region. The electricity network of the South East Europe region is highly interconnected, energy policies are increasingly harmonised and the electricity market is increasingly integrated as a result of the EU accession process, the Energy Community Treaty and more recently the Energy Union initiative warranting a regional perspective on policy development.

A model-based assessment of different long term electricity investment strategies was carried out for the region within the scope of the SEERMAP project. The project builds on previous work in the region, in particular IRENA (2017), the DiaCore and BETTER EU research projects and the SLED project, as well as on EU level analysis, in particular the EU Reference Scenario 2013 and 2016. The current assessment shows that alternative solutions exist to replace current generation capacity by 2050, with different implications for affordability, sustainability and security of supply.

Serbia will need to replace approximately 55% of its current fossil fuel generation capacity by the end of 2035 and the rest by 2050. This provides both a challenge to ensure a policy framework which will incentivise needed new investment, and an opportunity to shape the electricity sector over the long term in line with a broader energy transition unconstrained by the current generation portfolio.

A set of five models covering the electricity and gas markets, the transmission network and macro-economic system were used to assess the impact of 3 core scenarios:

- The 'no target' scenario reflects the implementation of current energy policy (including implementation of renewable energy targets for 2020 and completion of all power plants listed in official planning documents) combined with a $CO_2$ price (applied from 2030 onwards for non-EU states), but no 2050 $CO_2$ target in the EU or Western Balkans;
- The 'decarbonisation' scenario reflects a long-term strategy to significantly reduce $CO_2$ emissions according to indicative EU emission reduction goals for the electricity sector as a whole by 2050, driven by the $CO_2$ price and strong, continuous RES support;
- The 'delayed' scenario envisages an initial implementation of current national investment plans followed by a change in policy from 2035 onwards that leads to the same emission reduction target by 2050 as the 'decarbonisation' scenario. The attainment of the target is driven by the $CO_2$ price and increased RES support from 2035 onwards.

**The modelling work carried out under the SEERMAP project identifies some key findings** with respect to the different electricity pathways that Serbia can take:

- The Serbian electricity sector will face significant challenges. Under projected market conditions, domestic electricity production will not be competitive under any of the modelled scenarios. Coal and lignite based production, the only domestic resource where Serbia has a comparative advantage, will be priced out of the market due to the carbon price. Similarly, gas based electricity generation is uncompetitive since the gas price in Serbia is expected to be in the medium range in comparison with other countries in the SEERMAP region. Serbia's wind and solar potential is not especially high, and although production can be increased significantly compared with current levels, cost-effective RES potential will not cover total electricity demand. Hydro capacity is also limited. According to modelling results, Serbia will be a major net importer of electricity, with net imports reaching around 20-45% by 2050.

- High net imports have several positive implications despite the broadly negative perception among policymakers. Imports allow Serbia to maintain lower prices than producing all of its electricity domestically. The cost of increasing the value of the generation adequacy margin to zero (i.e. ensuring that domestic capacities are able to satisfy domestic demand in all hours of the year) would be significant – more than 200 mEUR/year after 2040. This cost can be avoided by relying heavily on imports.
- Due to the high net import levels, Serbia is able to decarbonise its electricity sector completely with relatively low levels of RES support, between 0.7-2.1 EUR/MWh throughout the entire period until 2050. If Serbia were to meet EU decarbonisation targets while relying more heavily on domestic renewable capacity, the required level of support would be significantly higher, given Serbia's relatively low RES potential in general.
- Delayed action on renewables is feasible, but has two disadvantages compared with a long term planned effort to decarbonise the electricity sector. First, it results in stranded fossil fuel power generation assets, including those currently planned. Translated into an electricity price increase equivalent over a 10 year period, the cost of stranded assets is more than the RES support required for decarbonising the electricity sector, at 2.2-2.3 EUR/MWh. Furthermore, the ramp up in RES deployment over the last five years before 2050 to meet the $CO_2$ emissions target requires a significant increase in RES support, with support levels in the last five years before 2050 reaching more than ten times the average level of support under a long term planned decarbonisation strategy.
- Whether or not Serbia pursues an active policy to support renewable electricity generation, a significant replacement of fossil fuel generation capacity will take place. Even in the 'no target' scenario coal and lignite capacities combined provide only around 5% of total electricity generation in 2050, and an even lower level of total consumption. The decrease in the share of coal and lignite begins early in the period, driven by the rising price of carbon which results in unprofitable utilisation rates.
- Natural gas will not be relevant in Serbia's domestic generation. It will account for less than 10% of electricity consumption even in the 'no target' scenario, and will become almost irrelevant in the two scenarios with a decarbonisation target after 2030.
- Decarbonisation of the electricity sector does not drive up wholesale electricity prices compared to a scenario where no emission reduction target is set. The price of electricity follows a similar trajectory under all scenarios and only diverges after 2045. After this year, prices are lower in scenarios with high levels of RES in the electricity mix due to the low marginal cost of RES electricity production.
- Under all scenarios there is a significant increase in the wholesale electricity price compared with current (albeit historically low) price levels. This characterises the SEE region and the EU as a whole in all scenarios for the modelled time period. The wholesale electricity price increase is driven by the price of carbon and natural gas (which remains relevant for the region, although not Serbia), both of which increase significantly by 2050. While this will result in higher absolute end user prices, the macroeconomic analysis shows that household electricity expenditure relative to household income is expected to increase only slightly in all scenarios. A benefit of higher wholesale prices is the positive investment signal it sends to investors in a sector currently beset by under-investment.
- Unlike other countries, decarbonisation in Serbia will not require more investment into generation capacity if compared to the 'no target' scenario. The investment portfolio

will shift from coal to solar and wind, resulting in a different financial profile for private actors, with higher CAPEX and lower OPEX. From a social point of view, without significant investment in the 'decarbonisation' scenario, the positive impact on GDP and employment occurring in most other countries is also absent in Serbia.

- Decarbonisation will require continuous RES support across the entire period. However, the need for support decreases as electricity wholesale prices increase and incentivise significant RES investment even without support.
- Across the modelled scenarios an incentive to invest in natural gas infrastructure is absent since gas generation remains insignificant, although it could be warranted from demand in other sectors such as the buildings sector or industry.
- Required network investments in transmission and cross border capacities by 2050 are moderate. Several possible transmission network contingencies within Serbia and its neighbouring connections are identified for 2030 and 2050, but costs of solving these problems do not exceed 52 mEUR in 2050, in addition to the implementation of investments included in ENTSO-E TYNDP 2016.

**A number of no regret policy recommendations can be provided based on results which are robust across all scenarios:**

- The high penetration of RES in all scenarios suggests a policy focus on enabling RES integration; this involves investing in transmission and distribution networks, enabling demand side management and RES production through a combination of technical solutions and appropriate regulatory practices, and promoting investment in storage solutions including hydro and small scale storage.
- RES potential can be maximised with de-risking policies lowering high cost of capital prevalent throughout the region. In Serbia this would pave the way for cost-efficient renewable energy investments.
- Within the SEERMAP region the share of net imports is highest in Serbia. The advantages of high imports, e.g. capping domestic prices and RES support, should be weighed against potential disadvantages. Furthermore, this should consider that Serbia will become an EU member state during the modelled timeframe, with EU energy policy increasingly moving towards integration, harmonisation and solidarity between member states.
- Regional level planning, including the establishment of regional markets, cross-border capacities and storage capacities, can improve system adequacy relative to plans emphasising reliance on national production capacities.
- Energy efficiency potential was not analysed, as all scenarios were based on the same demand projection. However, the results of the modelling suggest energy efficiency can reduce electricity imports and help meet decarbonisation targets more cost-effectively.
- In order to enable Serbia to decarbonise its electricity sector to the level suggested by the EU Roadmap, an active, long-term and stable renewable energy support framework is needed. A significant share of the RES support can be covered by EU ETS revenues, thereby relieving the corresponding (albeit low) surcharge to consumers.
- Policymakers need to address the trade-offs associated with fossil fuel investments. Coal generation capacities are expected to be priced out of the market before the end of their lifetime in all scenarios, resulting in stranded assets. These long term costs need to be weighed against any short term benefits, particularly associated with gas, which temporarily bridges the transition from coal and lignite to renewables.

# 2 | Introduction

## 2.1 Policy context

Over the past decades EU energy policy has focused on a number of shifting priorities. Beginning in the 1990s, the EU started a process of market liberalisation in order to ensure that the energy market is competitive, providing cleaner and cheaper energy to consumers. Three so-called energy packages were adopted between 1996 and 2009 addressing market access, transparency, regulation, consumer protection, interconnection, and adequate levels of supply. The integration of the EU electricity market was linked to the goal of increasing competitiveness by opening up national electricity markets to competition from other EU countries. Market integration also contributes to energy security, which had always been a priority but gained renewed importance again during the first decade of the 2000s due to gas supply interruptions from the dominant supplier, Russia. Energy security policy addresses short and long term security of supply challenges and promotes the strengthening of solidarity between member states, completing the internal market, diversification of energy sources, and energy efficiency.

The Energy Community Treaty and related legal framework translates EU commitments on internal energy market rules and principles into commitments for the candidate and potential candidate countries. Other regional processes and initiatives, such as CESEC and the Western Balkan 6 initiative, also known as the Berlin Process, also have implications for regional energy policy and legislation, infrastructure and markets.

Climate mitigation policy is inextricably linked to EU energy policy. Climate and energy were first addressed jointly via the so-called '2020 Climate and energy package' initially proposed by the European Commission in 2008. This was followed by the '2030 Climate and energy framework', and more recently by the new package of proposed rules for a consumer centred clean energy transition, referred to as the 'winter package' or 'Clean energy for all Europeans'. The EU has repeatedly stated that it is in line with the EU objective, in the context of necessary reductions according to the IPCC by developed countries as a group, to reduce its emissions by 80-95% by 2050 compared to 1990, in order to contribute to keeping global average temperature rise below 2°C compared with pre-industrial levels. The EU formally committed to this target in the 'INDC of the European Union and its 28 Member States'. The 2050 Low Carbon and Energy Roadmaps reflect this economy-wide target. The impact assessment of the Low Carbon Roadmap shows that the cost-effective sectoral distribution of the economy-wide emission reduction target translates into a 93-99% emission reduction target for the electricity sector (EC 2011a). The European Commission is in the process of updating the 2050 roadmap to match the objectives of the Paris Agreement, possibly reflecting a higher level of ambition than the roadmap published in 2011.

## 2.2 The SEERMAP project at a glance

The South East Europe Electricity Roadmap (SEERMAP) project develops electricity sector scenarios until 2050 for the South East Europe region. Geographically the SEERMAP project focuses on 9 countries in South East Europe: Albania, Bosnia and Herzegovina, Kosovo* (in line with UNSCR 1244 and the ICJ Opinion on the Kosovo declaration of independence), former Yugoslav Republic of Macedonia (Macedonia), Montenegro and Serbia (WB6) and

Bulgaria, Greece and Romania (EU3). The SEERMAP region consists of EU member states, as well as candidate and potential candidate countries. For non-member states some elements of EU energy policy are translated into obligations via the Energy Community Treaty, while member states must transpose and implement the full spectrum of commitments under the EU climate and energy acquis.

Despite the different legislative contexts, the countries in the region have a number of shared challenges. These include an aged electricity generation fleet in need of investment to ensure replacement capacity, consumers sensitive to high end user prices, and challenging fiscal conditions. At the same time, the region shares opportunity in the form of large potential for renewables, large potential of hydro generation which can be a valuable asset for system balancing, a high level of interconnectivity, and high fossil fuel reserves, in particular lignite, which is an important asset in securing electricity supply.

Taking into account the above policy and socio-economic context, and assuming that the candidate and potential candidate countries will eventually become member states, the SEERMAP project provides an assessment of what the joint processes of market liberalisation, market integration and decarbonisation mean for the electricity sector of the South East Europe region. The project looks at the implications of different investment strategies in the electricity sector for affordability, sustainability and security of supply.

The aim of the analysis is to show the challenges and opportunities ahead and the trade-offs between different policy goals. The project can also contribute to a better understanding of the benefits that regional cooperation can provide for all involved countries. Although ultimately energy policy decisions will need to be taken by national policy makers, these decisions must recognise the interdependence of investment and regulatory decisions of neighbouring countries. Rather than outline specific policy advise in such a complex and important topic, our aim is to support an informed dialogue at the national and regional level so that policymakers can work together to find optimal solutions.

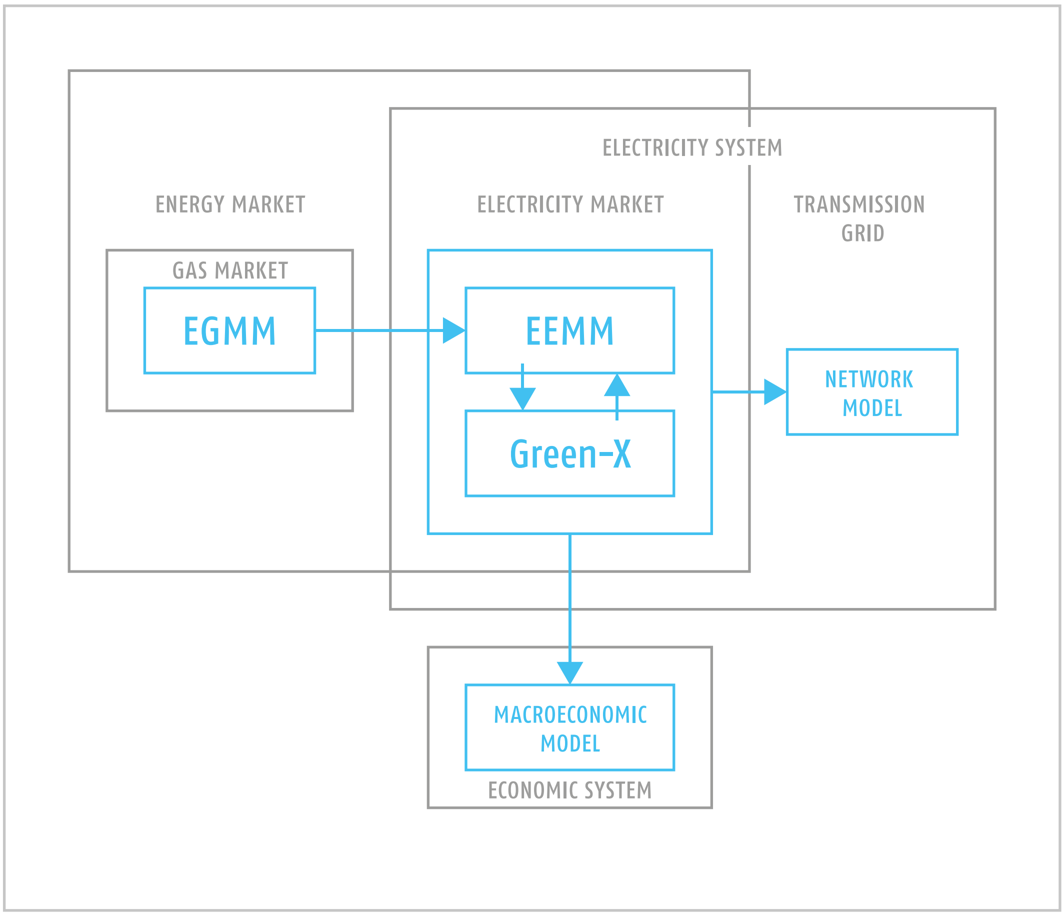
### 2.3 Scope of this report

This report summarises the contribution of the SEERMAP project to the ongoing policy debate on how to enhance the decarbonisation of the electricity sector in Serbia. We inform on the work undertaken, present key results gained and offer a summary of key findings and recommendations on the way forward. Please note that further information on the analysis conducted on other SEERMAP countries can be found in the individual SEERMAP country reports, and a Regional Report is also produced.

# 3 | Methodology

Electricity sector futures are explored using a set of five high resolution models incorporating the crucial factors which influence electricity policy and investment decisions. The European Electricity Market Model (EEMM) and the Green-X model together assess the impact of different scenario assumptions on power generation investment and dispatch decisions. The EEMM is a partial equilibrium microeconomic model. It assumes that the electricity market is fully liberalised and perfectly competitive. In the model, electricity generation as well as cross border capacities are allocated on a market basis without

**FIGURE 1**
THE FIVE MODELS USED FOR THE ANALYSIS
*A detailed description of the models is provided in a separate document ("Models used in SEERMAP")*




gaming or withholding capacity: the cheapest available generation will be used, and if imports are cheaper than producing electricity domestically demand will be satisfied with imports. Both production and trade are constrained by the available installed capacity and net transfer capacity (NTC) of cross border transmission networks respectively. Due to these capacity constraints, prices across borders are not always equalised. Investment in new generation capacity is either exogenous in the model (based on official policy documents), or endogenous. Endogenous investment is market-driven; power plant operators anticipate costs over the upcoming 10 years and make investment decisions based exclusively on profitability. If framework conditions (e.g. fuel prices, carbon price, available generation capacities) change beyond this timeframe then the utilisation of these capacities may change and profitability is not guaranteed.

The EEMM models 3400 power plant units in a total of 40 countries, including the EU, Western Balkans, and countries bordering the EU. Power flow is ensured by 104 interconnectors between the countries, where each country is treated as a single node. The fact that the model includes countries beyond the SEERMAP region incorporates the impact of EU market developments on the SEERMAP region.

The EEMM model has an hourly time step, modelling 90 representative hours with respect to load, covering all four seasons and all daily variations in electricity demand. The selection of these hours ensures that both peak and base load hours are represented, and that the impact of volatility in the generation of intermittent RES technologies on wholesale price levels is captured by the model. The model is conservative with respect to technological developments and thus no significant technological breakthrough is assumed (e.g. battery storage, fusion, etc.).

The Green-X model complements the EEMM with a more detailed view of renewable electricity potential, policies and capacities. The model includes a detailed and harmonised methodology for calculating long-term renewable energy potential for each technology using GIS-based information, technology characteristics, as well as land use and power grid constraints. It considers the limits to scaling up renewables through a technology diffusion curve which accounts for non-market barriers to renewables but also assumes that the cost of these technologies decrease over time, in line with global deployment (learning curves). The model also considers the different cost of capital in each country and for each technology by using country and technology specific weighted average cost of capital (WACC) values.

An iteration of EEMM and Green-X model results ensures that wholesale electricity prices, profile based RES market values and capacities converge between the two models.

In addition to the two market models, three other models are used:

- the European Gas Market Model (EGMM) to provide gas prices for each country up to 2050 used as inputs for EEMM;
- the network model is used to assess whether and how the transmission grid needs to be developed due to generation capacity investments, including higher RES penetration;
- macroeconomic models for each country are used to assess the impact of the different scenarios on macroeconomic indicators such as GDP, employment, and the fiscal and external balances.

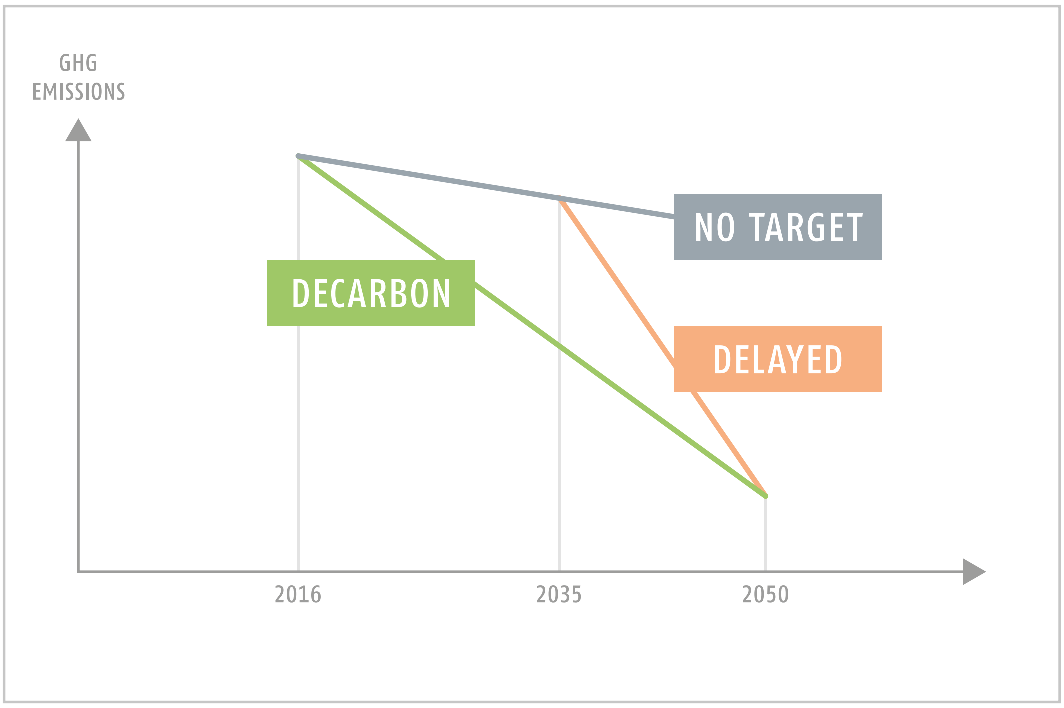
# 4 | Scenario descriptions and main assumptions

## 4.1 Scenarios

From a policy perspective, the main challenge in the SEE region in the coming years is to ensure sufficient replacement of aging power plants within increasingly liberalised markets, while at the same time ensuring affordability, security of supply and a significant reduction of greenhouse gas emissions. There are several potential long-term capacity development strategies which can ensure a functioning electricity system. The roadmap assesses three core scenarios:

- The 'no target' scenario reflects the implementation of current energy policy and no $CO_2$ target in the EU and Western Balkans for 2050;
- The 'decarbonisation' scenario reflects a continuous effort to reach significant reductions of $CO_2$ emissions, in line with long term indicative EU emission reduction goal of 93-99% emission reduction for the electricity sector as a whole by 2050;
- The 'delayed' scenario involves an initial implementation of current investment plans followed by a change in policy direction from 2035 onwards, resulting in the realisation of the same emission reduction target in 2050 as the 'decarbonisation' scenario.

**FIGURE 2**
THE CORE SCENARIOS




The modelling work does not take into account the impacts of the new Large Combustion Plant BREF (Commission Implementing Decision of 2017/1442), as it entered into force in July 2017.

The same emission reduction target of 94% was set for the EU28+WB6 region in the 'delayed' and 'decarbonisation' scenarios. This implies that the emission reductions will be higher in some countries and lower in others, depending on where emissions can be reduced most cost-efficiently.

The scenarios differ with respect to the mix of new technologies, included in the model in one of two ways: (i) the new power plants entered exogenously into the model based on policy documents, and (ii) the different levels and timing of RES support resulting in different endogenous RES investment decisions. The assumptions of the three core scenarios are the following:

- In the 'no target' scenario all currently planned fossil fuel power plants are entered into the model exogenously. Information on planned power plants is taken from official national strategies/plans and information received from the local partners involved in the project. We have assumed the continuation of current renewable support policies up to 2020 and the gradual phasing out of support between 2021 and 2025. The scenario assumes countries meet their 2020 renewable target but do not set a $CO_2$ emission reduction target for 2050. Although a $CO_2$ target is not imposed, producers face $CO_2$ prices in this scenario, as well as in the others.
- In the 'decarbonisation' scenario, only those planned investments which had a final investment decision in 2016 were considered, resulting in lower exogenous fossil fuel capacity. With a 94% $CO_2$ reduction target, RES support in the model was calculated endogenously to enable countries to reach their decarbonisation target by 2050 with the necessary renewable investment. RES targets are not fulfilled nationally in the model, but are set at a regional level, with separate targets for the SEERMAP region and for the rest of the EU.

- The 'delayed' scenario considers that currently planned power plants are built according to national plans, similarly to the 'no target' scenario. It assumes the continuation of current RES support policies up to 2020 with a slight increase until 2035. This RES support is higher than in the 'no target' scenario, but lower than the 'decarbonisation' scenario. Support is increased from 2035 to reach the same $CO_2$ emission reduction target as the 'decarbonisation' scenario by 2050.

Due to the divergent generation capacities, the scenarios result in different generation mixes and corresponding levels of $CO_2$ emissions, but also in different investment needs, wholesale price levels, patterns of trade, and macroeconomic impacts.

## 4.2 Main assumptions

All scenarios share common framework assumptions to ensure the comparability of scenarios with respect to the impact of the different investment strategies over the next few decades. The common assumptions across all scenarios are described below.

**Demand:**

- Projected electricity demand is based – to the extent possible – on data from official national strategies. Where official projections do not exist for the entire period until 2050, electricity demand growth rates were extrapolated based on the EU Reference scenario for 2013 or 2016 (for non-MS and MS respectively). The PRIMES EU Reference scenarios assume low levels of energy efficiency and low levels of electrification of transport and space heating compared with a decarbonisation scenario. The average annual electricity growth rate for the SEERMAP region as a whole is 0.74% over the period 2015 and 2050. The annual demand growth rate for countries within the region is varies significantly, with the value for Greece as low as 0.2%, and for Bosnia and Herzegovina as high as 1.7%. Whereas the growth rate in all EU3 countries is below 0.7%, Macedonia is the only country in the WB6 where the growth rate is below 1% a year. For Serbia, the PRIMES EU Reference scenario growth rates were used from 2015 onwards due to limited data availability for the country. Serbia has an Energy Sector Development Strategy (2016), but projects only final electricity consumption and not gross electricity consumption used in the modelling, until 2030. This implies an average annual electricity growth rate of 1.0% over the period between 2016 and 2050. The latest ENTSO-E data on gross electricity consumption was used as a starting point for the projections to be as close to real electricity consumption as possible.
- Demand side management (DSM) measures were assumed to shift 3.5% of total daily demand from peak load to base load hours by 2050. The 3.5% assumption is a conservative estimate compared to other projections from McKinsey (2010) or TECHNOFI (2013). No demand side measures were assumed to be implemented before 2035.

**Factors affecting the cost of investment and generation:**

- Fossil fuel prices: Gas prices are derived from the EGMM model. The price of oil and coal were taken from IEA (2016) and EIA (2017) respectively. The price of coal is expected to increase by approximately 15% by 2050 compared with 2016. In the same period gas prices increase by around 75% and oil prices by around 250%. Compared to 2012-2013 levels, only a 15-20% increase in oil prices is assumed by 2050, because of historically low current price levels.

- Cost of different technologies: Information on the investment cost of new generation technologies is taken from EIA (2017).
- Weighted average cost of capital (WACC): The WACC has a significant impact on the cost of investment, with a higher WACC implying a lower net present value and therefore a more limited scope for profitable investment. The WACCs used in the modelling are country-specific, these values are modified by technology-specific and policy instrument-specific risk factors. The country-specific WACC values in the region are assumed to be between 10 and 15% in 2016, decreasing to between 9.6 and 11.2% by 2050. The value is highest for Greece in 2016, and remains one of the highest by 2050. In contrast, the WACC values for the other two EU member states, Romania and Bulgaria, are on the lower end of the spectrum, as are the values for Kosovo* and Macedonia. The country-specific WACC for Serbia was assumed to be 11% in 2015, decreasing to 10.2% by 2050. This is broadly in line with IRENA (2017) where the middle value for WACC for PV and wind was assumed to be 10% for Serbia.
- Carbon price: a price for carbon is applied for the entire modelling period for EU member states and from 2030 onwards in non-member states, under the assumption that all candidate and potential candidate countries will implement the EU Emissions Trading Scheme or a corresponding scheme by 2030. The carbon price is assumed to increase from 33.5 EUR/t$CO_2$ in 2030 to 88 EUR/t$CO_2$ by 2050, in line with the EU Reference Scenario 2016. This Reference Scenario reflects the impacts of the full implementation of existing legally binding 2020 targets and EU legislation, but does not result in the ambitious emission reduction targeted by the EU as a whole by 2050. The corresponding carbon price, although significantly higher than the current price, is therefore a medium level estimate compared with other estimates of EU ETS carbon prices by 2050. For example, the Impact Assessment of the Energy Roadmap 2050 projected carbon prices as high as 310 EUR under various scenarios by 2050 (EC 2011b). The EU ETS carbon price is determined by the marginal abatement cost of the most expensive abatement option, which means that the last reduction units required by the EU climate targets will be costly, resulting in steeply increasing carbon price in the post 2030 period.

**Infrastructure:**

- Cross-border capacities: Data for 2015 was available from ENTSO-E with future NTC values based on the ENTSO-E TYNDP 2016 (ENTSO-E 2016) and the 100% RES scenario of the E-Highway projection (ENTSO-E 2015b).
- New gas infrastructure: In accordance with the ENTSO-G TYNDP 2017 both the Transadriatic (TAP) and Transanatolian (TANAP) gas pipelines (see Annex 2) are built between 2016 and 2021, and the expansion of the Revithoussa and the establishment of the Krk LNG terminals are taken into account. No further gas transmission infrastructure development was assumed in the period to 2050.

**Renewable energy sources and technologies:**

- Long-term technical RES potential is estimated based on several factors including the efficiency of conversion technologies and GIS-based data on wind speed and solar irradiation, and is reduced by land use and power system constraints. It is also assumed that the long term potential can only be achieved gradually, with renewable capacity increase restricted over the short term. A sensitivity analysis measured the reduced potential of the most contentious RES capacities, wind and hydro. The results of the sensitivity analysis are discussed in section 5.5.

- Capacity factors of RES technologies were based on historical data over the last 5 to 8 years depending on the technology.

Annex 2 contains detailed information on the assumptions.

# 5 | Results

## 5.1 Main electricity system trends

The main investment challenge in Serbia is related to existing lignite capacities. Approximately 55% of current lignite generation capacity, more than 2400 MW, is expected to be decommissioned by the end of 2035, and 100% by 2050.

The model results show that in all scenarios the least cost capacity options are renewables, especially hydro, and to some extent wind, by 2050. The generation mix changes significantly in all three scenarios, shifting from fossil fuel to renewable capacity, driven primarily by increasing carbon prices and decreasing renewable technology costs. Lignite based electricity generation drops below 6% in the 'no target' and 'delayed' scenarios and disappears completely in the 'decarbonisation' scenario by 2050.

Even in scenarios where lignite investment is taken in to account according to national plans, Serbia will only generate a very small percentage of its electricity from lignite by 2050. In a competitive electricity market, Serbian power plants compete with other power plants in the region and the EU due to strong interconnections. The wholesale electricity price and carbon price have a major influence on the type of power plants that come online at any given moment to satisfy demand. In scenarios where lignite based new power plants are built according to national plans, these new power plants are idle for most of the year by 2050 due to high carbon costs. The analysis shows that national policy makers therefore have little scope to influence the electricity mix over the long term through investment decisions.

Renewables play an increasingly important role in all three scenarios. The RES capacities with the highest increase from current levels are wind and solar. Absent a $CO_2$ emission reduction target and with renewable subsidies phased out under the 'no target' scenario, the share of RES in electricity consumption will reach slightly above 50% in 2050; this is equivalent to almost 90% as a share of electricity generation. Significant new hydro capacities appear in all scenarios reflecting the relatively low cost of hydro generation; the increase in capacity is around 60% compared with current levels. There is also a large wind capacity increase in the two scenarios with a decarbonisation target. New wind investment is highest in the 'delayed' scenario towards the end of the modelled period, but it also makes a significant contribution in the 'decarbonisation' scenario, with a 27% share of electricity generation by 2050. Solar makes a relatively minor contribution by comparison, with less than a 10% share in electricity generation in both the 'delayed' and 'decarbonisation' scenarios. Small scale photovoltaic installations compete against end-user electricity prices, whereas other renewables such as wind technology compete at the wholesale electricity price. Despite this, solar proves to be relatively uncompetitive in Serbia over the modelled time period. The share of biomass in the capacity mix increases but remains insignificant in all three scenarios.

**FIGURE 3**
INSTALLED CAPACITY IN THE 3 CORE SCENARIOS UNTIL 2050 (GW) IN SERBIA, 2020-2050

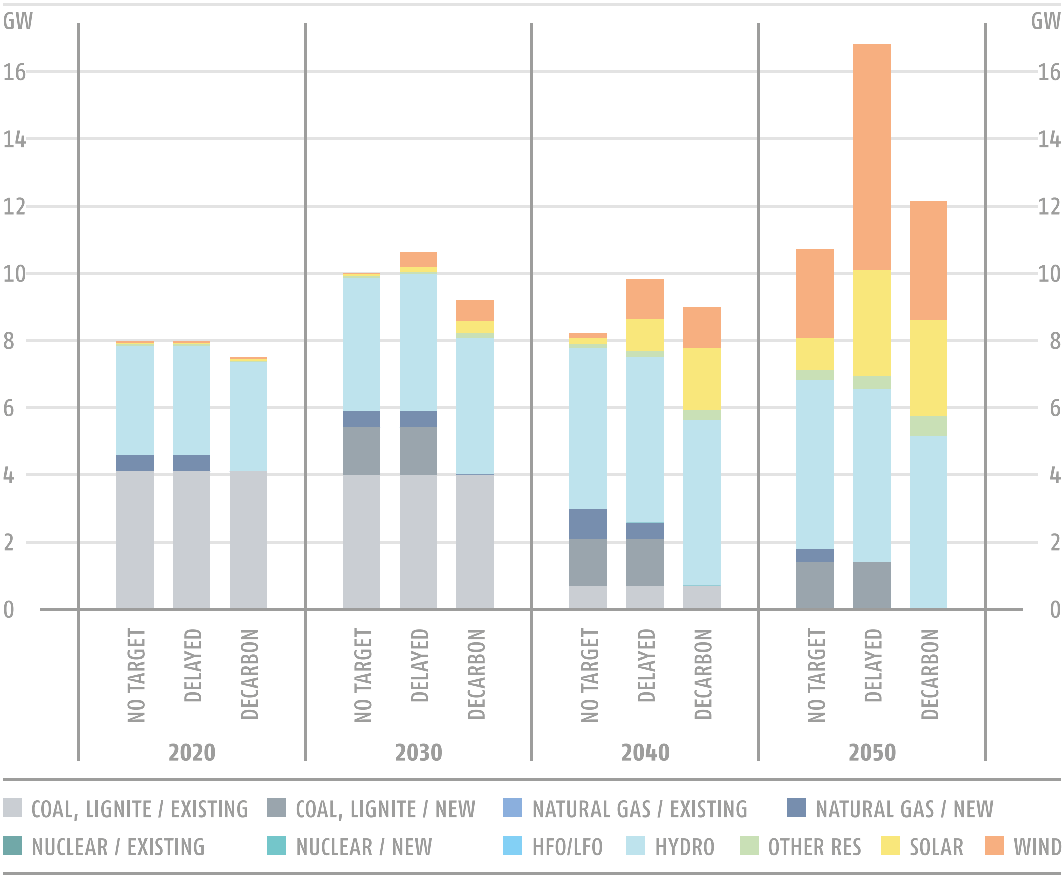



**FIGURE 4**
ELECTRICITY GENERATION AND DEMAND (TWh) AND RES SHARE (% OF DEMAND) IN SERBIA, 2020-2050

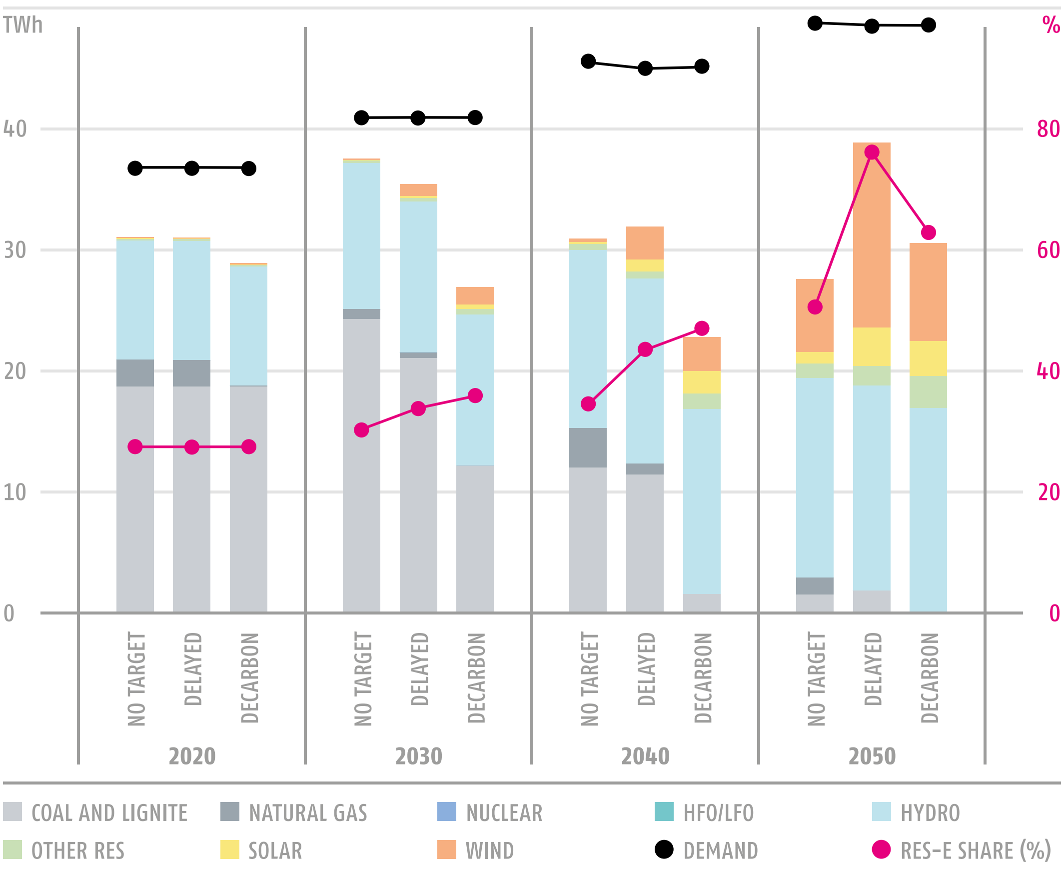
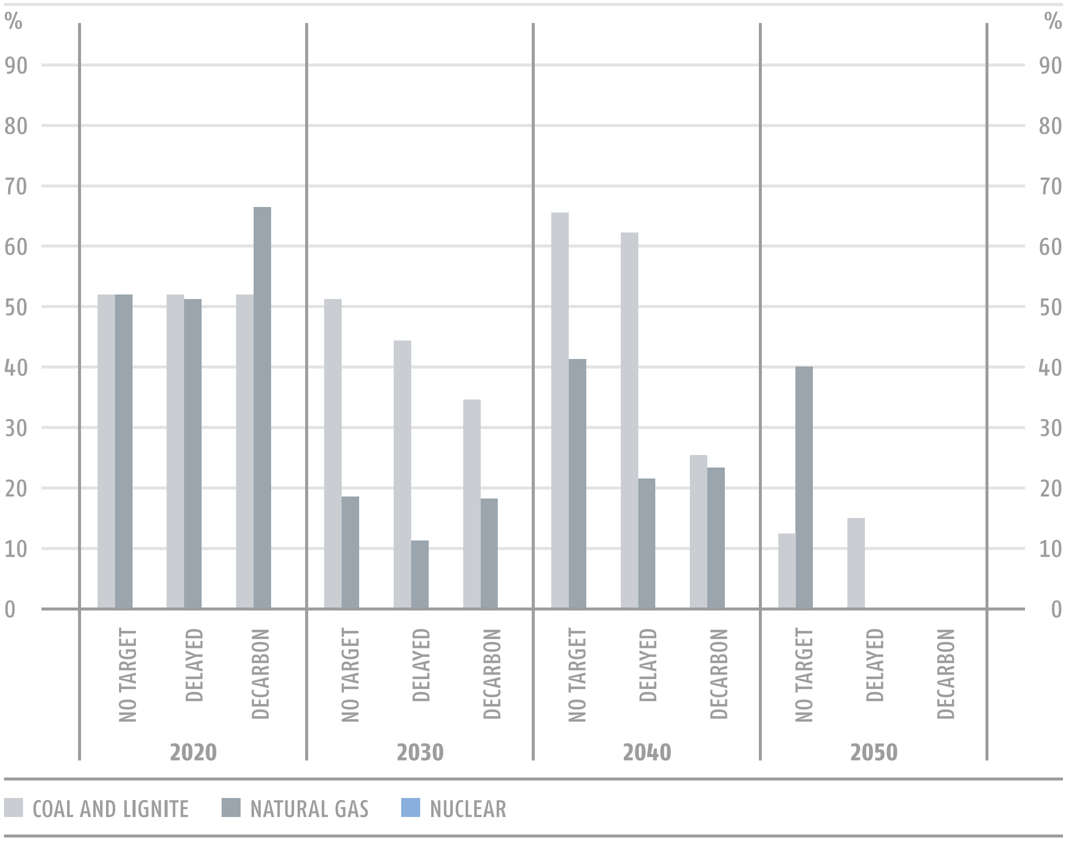


**FIGURE 5**
UTILISATION RATES OF CONVENTIONAL GENERATION IN SERBIA, 2020-2050 (%)



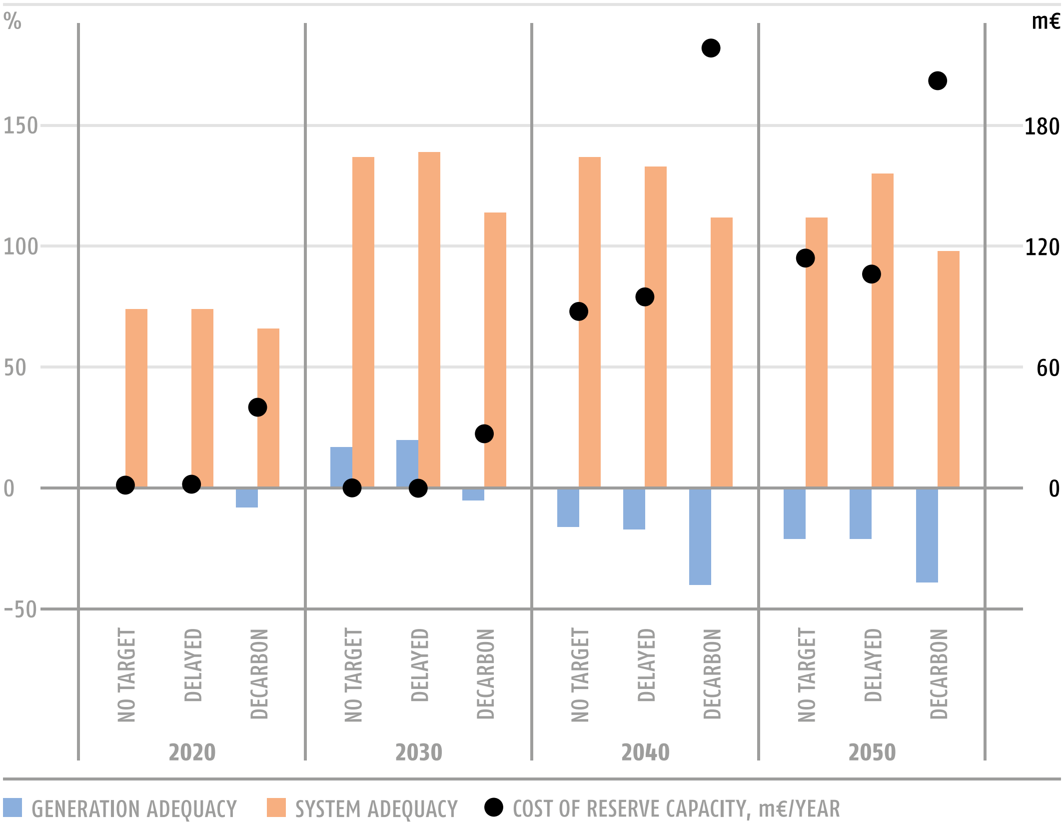

Natural gas plays a limited role in electricity generation in all three scenarios, peaking in 2025 in the 'no target' and 'delayed' scenarios at around 10%, and peaking in 2045 in the 'no target' scenario. Natural gas based electricity generation is virtually absent from the 'decarbonisation' scenario. The initial increase in gas based electricity generation is driven by the carbon price, which prices out coal and lignite generation before sufficient renewable capacity is installed. Eventually, towards the end of the modelled time horizon, as the carbon price continues to rise and renewable technologies become cheaper, gas based generation declines.

The 'no target' and 'delayed' scenarios assume that the 478 MW Pancevo CCGT comes online in 2019, in accordance with national plans available at the time of modelling in 2016. In addition, a new 400 MW capacity gas plant is added by the model by 2040 in the 'no target' scenario. Meanwhile, the total natural gas generation capacity in the 'decarbonisation' scenario is 10 MW.

With electricity markets opening, Serbia has begun importing electricity and this will continue according to the model in all scenarios. Large net imports are a result of the relative disadvantage that Serbia has in electricity production; around three quarters of its hydro capacity is utilised by 2050 and wind and solar capacities are less competitive at the regional electricity price level. Lignite and coal capacities are priced out by the increasing carbon price, and gas prices are in the medium range relative to other countries in the region. By 2050, imports reach around 43% of gross consumption in the 'no target', 20% in the 'delayed' and 37% in the 'decarbonisation' scenario.

The utilisation rate of coal plants remains relatively stable until 2045 in the 'no target' and 'delayed' scenarios, in the range of 43-66%, but then drop below commercially viable levels after 2045. In the 'decarbonisation' scenario, coal utilisation rates drop below 20%

**FIGURE 6**
GENERATION AND SYSTEM ADEQUACY MARGIN FOR SERBIA, 2020-2050 (% OF LOAD)




by 2035 and coal capacity disappears completely by 2050. Gas utilisation rates are initially high and fall towards the middle of the period in all three core scenarios. The utilisation rate recovers in the 'no target' scenario by 2050 with high electricity prices allowing for profitable gas power plant operation. In the two scenarios with a decarbonisation target, gas disappears from the electricity mix by 2050. This shows, that if there is an ambitious decarbonisation target the cost of gas and coal or lignite generation investments made at the beginning of the modelled period can be recovered, but investments made closer to 2040 may be stranded. This issue is discussed further in section 5.4.

## 5.2 Security of supply

Even though the physical and commercial integration of national electricity markets improves security of supply, concerns of decision makers often remain regarding the extent and robustness of this improvement, particularly in the context of a high share of renewables. In order to assess the validity of such concerns three security of supply indices were calculated for all countries and scenarios: the generation capacity margin, the system adequacy margin, and the cost of increasing the generation adequacy margin to zero.

The generation adequacy margin is defined as the difference between available capacity and hourly load as a percentage of hourly load. If the resulting value is negative, then the load cannot be satisfied with domestic generation capacities alone in a given hour, and imports are needed. The value of the generation adequacy margin was calculated for all of the modelled 90 representative hours, the lowest generation adequacy margin value was taken into account in the generation adequacy margin indicator. For this calculation, assumptions were made with respect to the maximum availability of different technologies: fossil fuel based power plants are assumed to be available 95% of the time, hydro storage 100% and for other RES technologies historical availability data was used. System adequacy was defined in a similar way, but net transfer capacity available for imports was considered in addition to available domestic capacity. This is a simplified version of the methodology formerly used by ENTSO-E. (See e.g. ENTSO-E, 2015, and previous SOAF reports)

For Serbia, the generation adequacy margin is negative during the second half of the modelled time period for all scenarios and for the entire modelling period in the 'decarbonisation' scenario. This means domestic generation capacity is not sufficient to satisfy domestic demand in some hours of the year during this time period. However, the system adequacy margin is positive, indicating that demand can be satisfied during all hours if import potential is considered in addition to domestic capacities.

The cost of increasing the generation adequacy margin to zero was calculated for countries with initially negative values. This is defined as the yearly fixed cost of an open cycle gas turbine (OCGT) with the capacity to ensure that the generation adequacy margin reaches zero. This can be interpreted as a capacity fee, provided that capacity payments are only made to new generation, and that the goal of the payment is to improve the generation adequacy margin to zero. The cost of reserve capacity is highest for the 'decarbonisation' scenario, at 219 mEUR/year in 2040 and 203 mEUR/year in 2050, while it is about half in the other two scenarios. This demonstrates the importance of regional markets and interconnectivity for reducing costs in scenarios with high shares of renewable generation.

## 5.3 Sustainability

The $CO_2$ emissions of the three core scenarios were calculated based on representative emission factors for the region. Due to data limitations this calculation did not account for greenhouse gases other than $CO_2$ and does not include emissions related to heat production from cogeneration.

The 94% overall decarbonisation target for the EU28+WB6 region translates into a higher than average level of decarbonisation for the Serbian electricity sector. By 2050 $CO_2$ emissions from the electricity sector in Serbia are reduced by 100% in the 'decarbonisation' scenario compared to 1990 levels. Paradoxically, this is not due to the high renewable potential in Serbia. Instead, this high level of emission reduction is made possible by two factors: coal and lignite based generation are completely priced out of the market and a high share of electricity import that does not count towards emissions for Serbia, but the country where electricity generation takes place. Emission reduction is also high in the 'no target' scenario, reaching 94% by 2050, attributable to the same factors.

The share of renewable generation as a percentage of gross domestic consumption in 2050 is 50.6% in the 'no target' scenario, 76.2% in the 'delayed' scenario and 63.0% in the 'decarbonisation' scenario. In the scenario with the highest RES share in 2050 (the 'delayed' scenario) long term RES potential utilisation reaches 75% for hydro, 92% for wind and 48% for solar. This means that a very significant share of RES potential is used in Serbia by the end of the modelled period if this scenario is implemented.

## 5.4 Affordability and competitiveness

In the market model (EEMM) the wholesale electricity price is determined by the highest marginal cost of the power plants needed to satisfy demand. The price trajectories are independent of the level of decarbonisation and similar in all scenarios, only diverging

**FIGURE 7**
$CO_2$ EMISSIONS UNDER THE 3 CORE SCENARIOS IN SERBIA, 2020-2050 (mt)

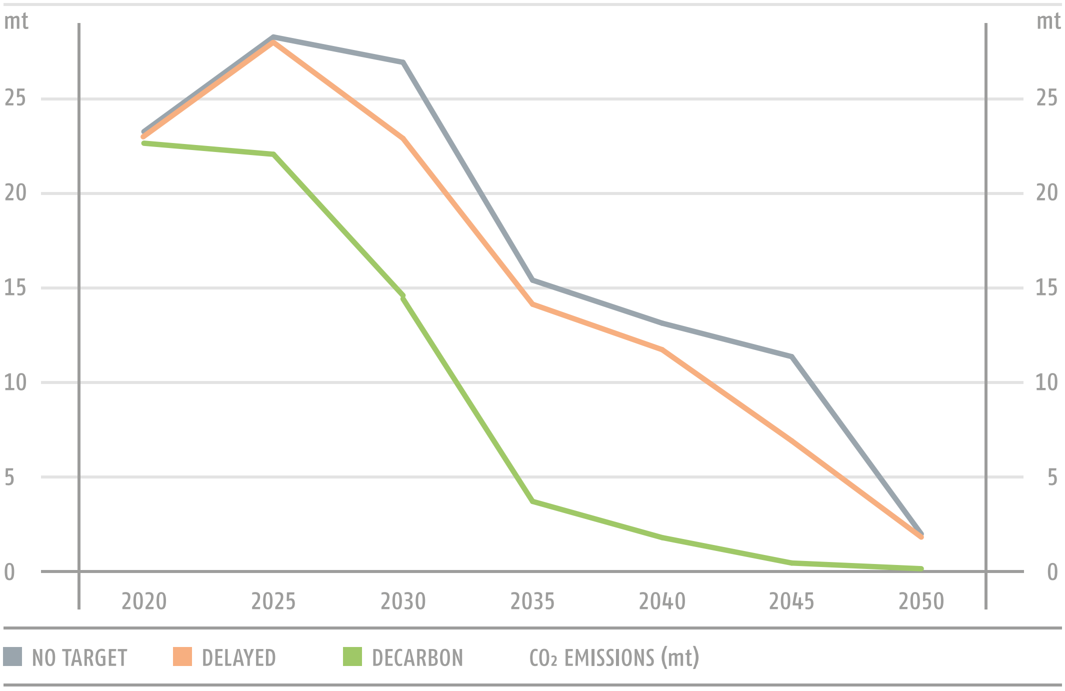



**FIGURE 8**
WHOLESALE ELECTRICITY PRICE IN SERBIA, 2020-2050 (€/MWh)

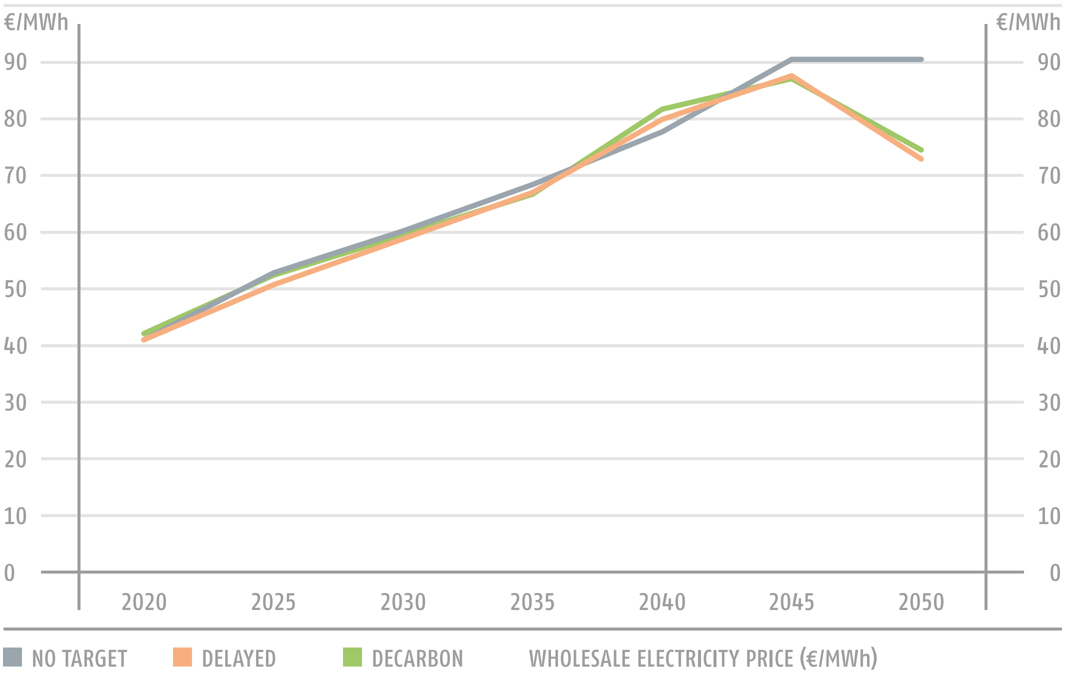
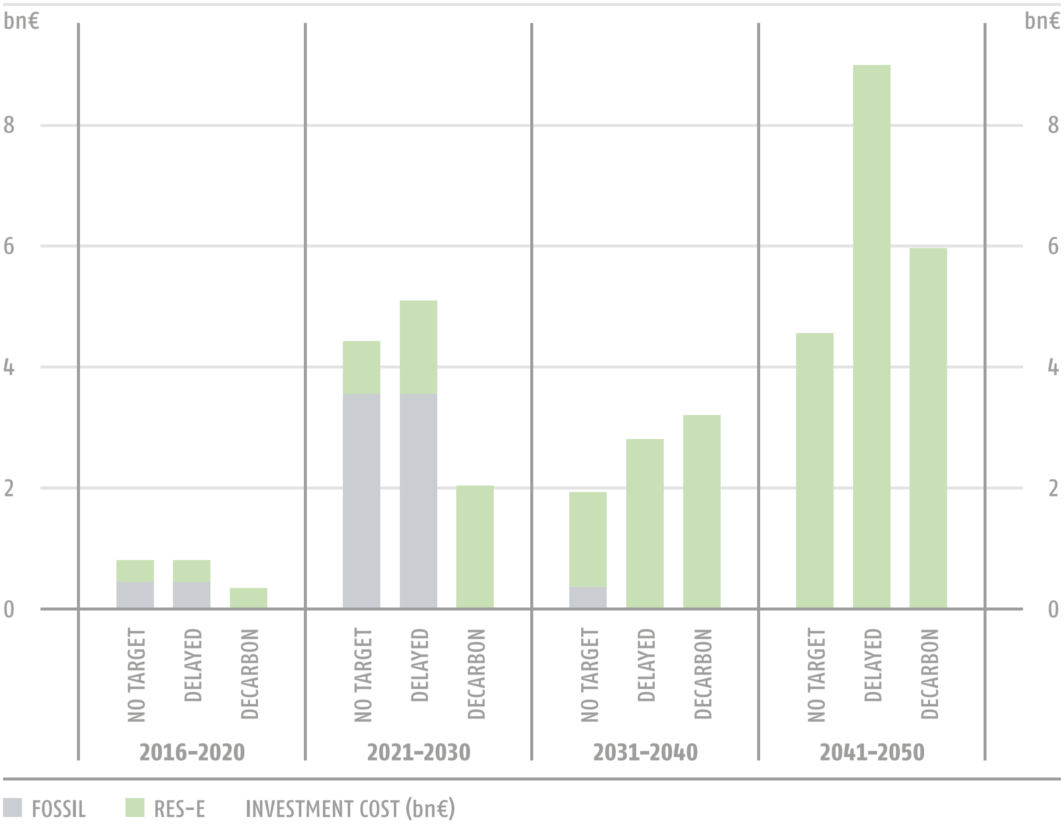


**FIGURE 9**
CUMULATIVE INVESTMENT COST FOR 4 AND 10 YEAR PERIODS, 2016-2050 (bn€)

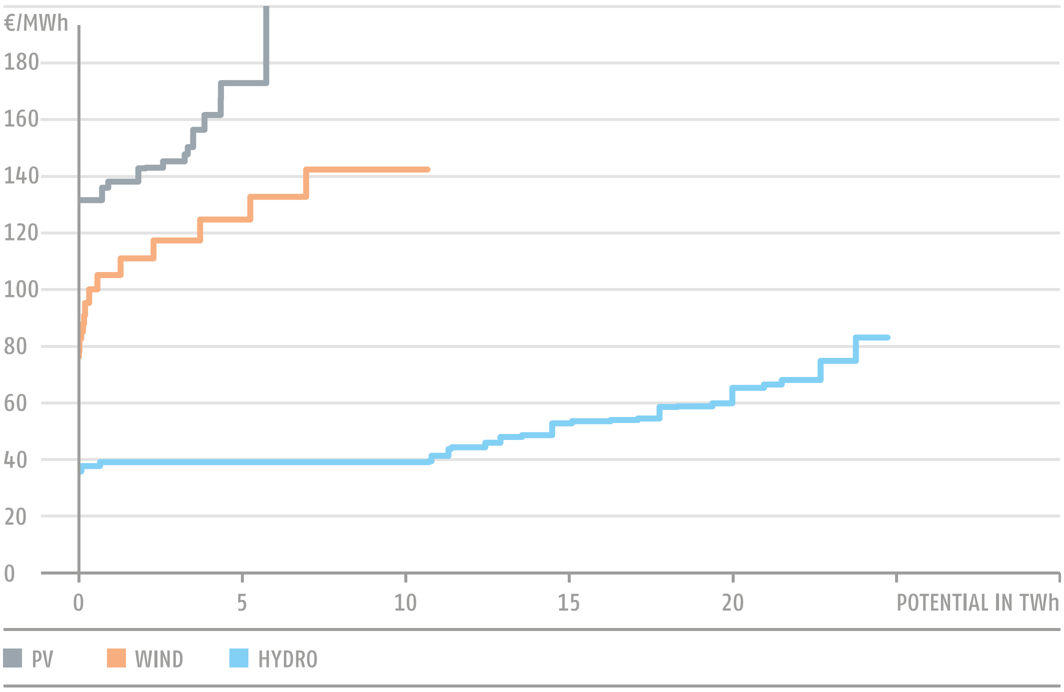



after 2045 when the two scenarios with decarbonisation targets result in lower wholesale prices. This is due to the fact that towards 2050 the share of renewables is high enough to satisfy demand in most hours at a low cost, driving the average annual price down.

The price development has several implications for policy makers. Retail prices depend on the wholesale price as well as taxes, fees and network costs. It is therefore difficult to project retail price evolution based on wholesale price information alone, but it is an important determinant of end user prices and could affect affordability for consumers. The average annual increase in price over the entire period is 2.8% in the 'no target' scenario and around 2.2% in the 'delayed' and 'decarbonisation' scenarios. The lower growth rate in the latter two scenarios is attributable to a decrease in the wholesale price during the last five years of the modelled time period. Although the price increase is significant, it is important to note that at the beginning of the analysis in 2016 wholesale electricity prices in Europe are at historical lows, and furthermore the analysis projects wholesale prices to increase to approximately 60 EUR/MWh by 2030 which is the price level from 10 years ago. Assessing macroeconomic outcomes in section 5.7, if affordability is measured as household electricity expenditure as a share disposable income, affordability deteriorates slightly in all scenarios. The price increase also has two positive implications, incentivising investment for new capacities and reducing the need for RES support.

The investment needed in new capacities is generally not higher in the 'decarbonisation' scenario than in the 'no target' scenario, but the timing and type of investments differ significantly. The 'no target' scenario assumes high levels of fossil fuel generation investments at the beginning of the modelled time horizon in line with national policy documents, whereas the 'decarbonisation' scenario involves higher investment in renewable capacities during the second half of the modelled time horizon. Overall

**FIGURE 10**
LONG TERM COST OF RENEWABLE TECHNOLOGIES IN SERBIA (€/MWh)




investment is highest in the 'delayed' scenario, with high initial levels of investment in fossil generation capacities similar to the 'no target' scenario, but also a peak investment period in RES capacities at the end of the modelled time period.

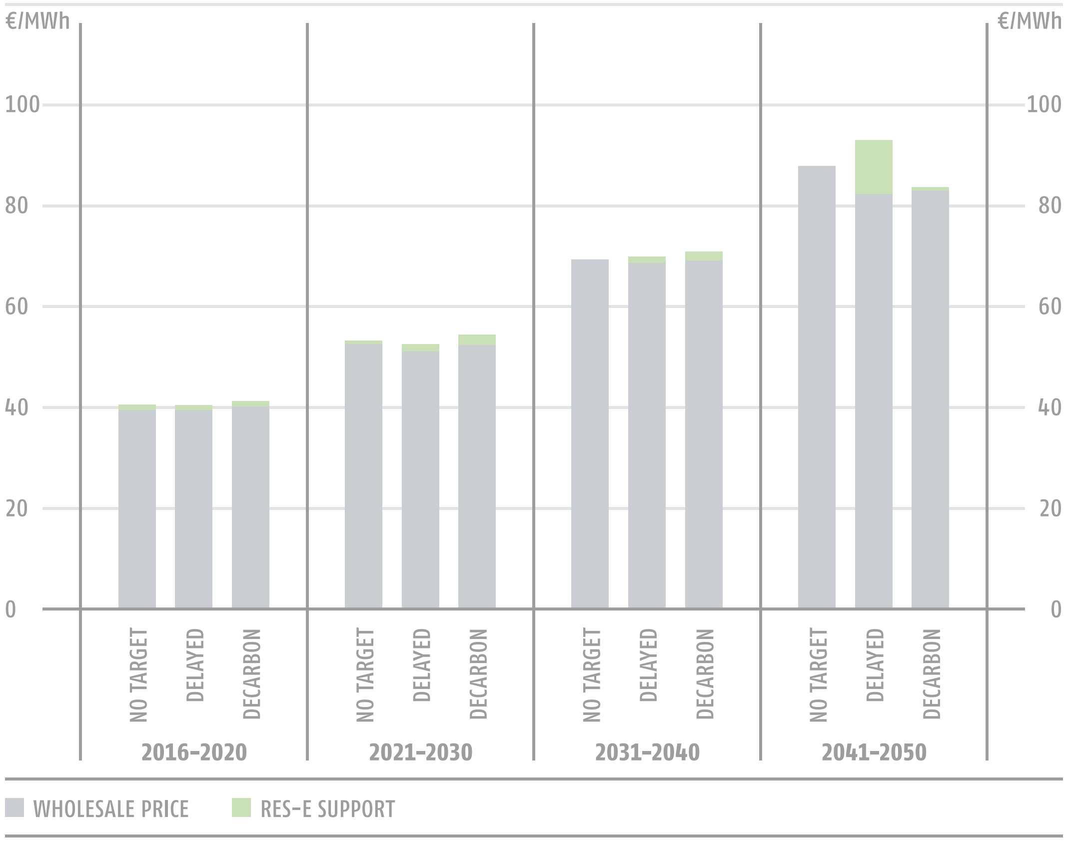
It is important to note that investment is financed by the private sector, based on a profitability requirement (apart from the capacities planned in the national strategies). Here the different cost structure of renewables is important for the final investment decision, i.e. the higher capital expenditure is compensated by low operating expenditure. From a social welfare point of view, the impact of the overall investment levels are limited to GDP, employment, the external balance and public debt. These findings are discussed in more detail in section 5.7.

With the exception of the last five years in the 'delayed' scenario, the renewables support required to incentivise low carbon investments over the entire modelling period is low. In the 'decarbonisation' scenario, RES support relative to the wholesale price plus RES support is below 4% throughout the modelled period until 2050 when it falls below 1%. These support levels are significantly lower than the average in the SEERMAP region because of the high level of imports and availability of low cost hydro capacity.

Although RES technologies are already at grid parity in some locations with costs falling further, some support will still be needed in 2050 to incentivise new investment. This is partly due to the locational impact: as the best locations with highest potential are used first, the levelised cost of new RES capacities might increase over time. The relationship between the cost of RES technologies and installed capacity is shown in Figure 10; the figure does not account for the learning curve impacts which were also considered in the Green-X model.

High levels of RES support are only needed in the last decade of the 'delayed' scenario to trigger significant investment in renewables. Otherwise, RES support falls over the period while investment in RES capacity increases. The broad decline in RES support is made possible mainly by the increasing wholesale price for electricity which reduces the need for residual support.

**FIGURE 11**
AVERAGE RES SUPPORT PER MWh OF TOTAL ELECTRICITY CONSUMPTION AND AVERAGE WHOLESALE PRICE, 2016-2050 (€/MWh)



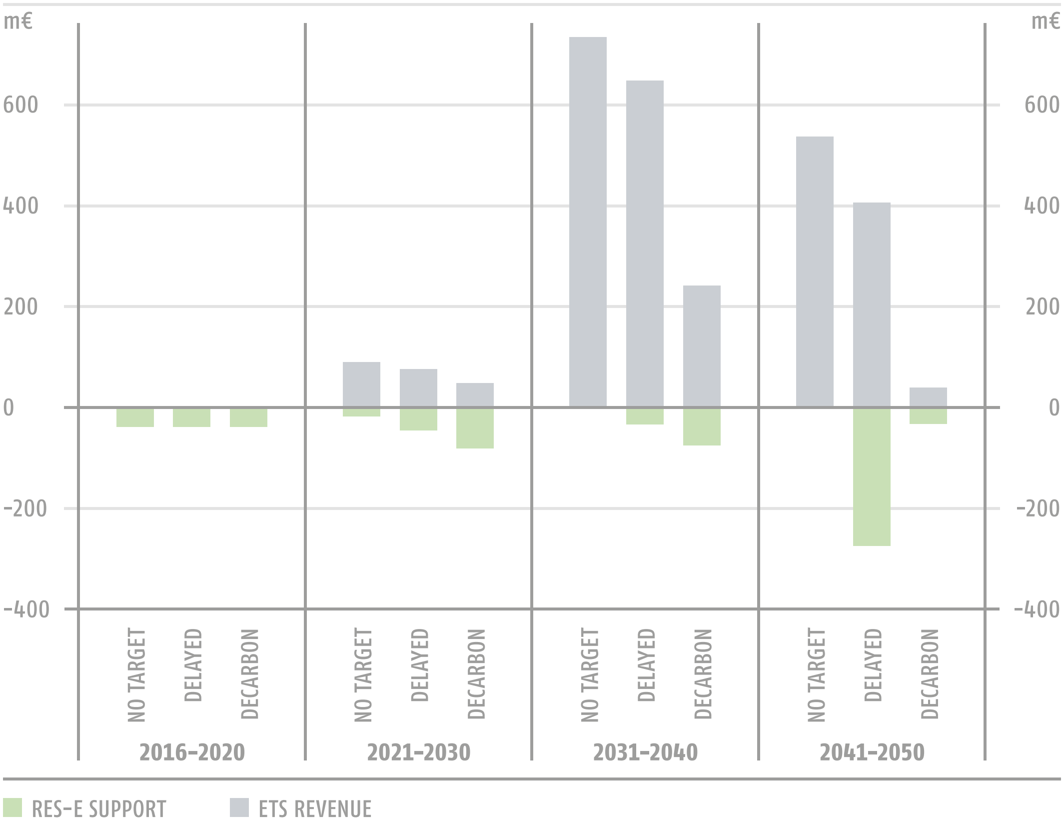

Renewable energy investments may be incentivised with a number of support schemes using funding from different sources; in the model sliding feed-in premium equivalent values are calculated. Revenue from the auction of carbon allowances under the EU ETS is a potential source of financing for renewable investment. Figure 12 contrasts cumulative RES support needs with ETS auction revenues, assuming 100% auctioning, and taking into account only allowances to be allocated to the electricity sector.

In the 'decarbonisation' scenario, auction revenues drop to almost zero by the end of the modelled time period because fossil fuel plants that receive an allocation disappear almost entirely from the Serbian capacity mix with the exception of small gas capacity. Overall the modelling results show that ETS revenues can cover all the needed support in the 'decarbonisation' scenario from 2031 onwards.

A financial calculation was carried out on the stranded costs of fossil based generation plants that are expected to be built in the period 2017-2050. New fossil generation capacities included in the scenarios are defined either by national energy strategy documents and entered into the model exogenously, or are built by the investment algorithm of the EEMM. The model's investment module assumes 10 year foresight, meaning that investors have limited knowledge of the policies applied in the distant future. The utilisation rate of fossil fuel generation assets drops below 15% in most SEERMAP countries after 2040; this means that capacities which generally need to have a 30-55 year lifetime (30 for CCGT, 40 for OCGT and 55 for coal and lignite plants) with a sufficiently high utilisation rate in order to ensure a positive return on investment will face stranded costs.

Large stranded capacities might call for public intervention with all the associated cost borne by society/electricity consumers. For this reason we have estimated the stranded

**FIGURE 12**
CUMULATIVE RES SUPPORT AND AUCTION REVENUES FOR 4 AND 10 YEAR PERIODS, 2016-2050 (m€)




costs of fossil based generation assets that were built in the period 2017-2050. The calculation is based on the assumption that stranded costs will be collected as a surcharge on the consumed electricity (as is the case for RES surcharges) for over a period of 10 years after these gas and lignite based capacities become unprofitable. Based on these calculations early retired fossil plants would have to receive 2.2 EUR/MWh, 2.3 EUR/MWh and 0 EUR/MWh surcharge over a 10 year period to cover their economic losses in the 'no target', 'delayed' and 'decarbonisation' scenarios respectively. These costs are not included in the wholesale price values shown in this report. The total stranded cost is 1033 mEUR in the 'no target' scenario, 1056 mEUR in the 'delayed' scenario, but only 7 mEUR in the 'decarbonisation' scenario.

## 5.5 Sensitivity analysis

In order to assess the robustness of the results, a sensitivity analysis was carried out with respect to assumptions that were deemed most controversial by stakeholders during consultations and tested for the following assumptions:

- Carbon price: to test the impact of a lower $CO_2$ price, a scenario was run which assumed that $CO_2$ prices would be half of the value used for the three core scenarios for the entire period until 2050;
- Demand: the impact of higher and lower demand growth was tested, with a +/-0.25% change in the growth rate for each year in all the modelled countries (EU28+WB6), resulting in a 8-9% deviation from the core trajectory by 2050;

**FIGURE 13**
GENERATION MIX (TWh) AND RES SHARE (% OF DEMAND) IN THE SENSITIVITY RUNS IN 2030 AND 2050


- RES potential: the potential for large-scale hydropower and onshore wind power were assumed to be 25% lower than in the core scenarios; this is where the NIMBY effect is strongest and where capacity increase is least socially acceptable.

The changes in assumptions were only applied to the 'decarbonisation' scenario since it represents a significant departure from the current policy for many countries, and it was important to test the robustness of results in order to convincingly demonstrate that the scenario could realistically be implemented under different framework conditions.

The most important conclusions of the sensitivity analysis are the following:

- The $CO_2$ price is a key determinant of wholesale prices and a 50% reduction in the value of the carbon price results in an approximately 33% reduction in the wholesale price over the long term. However, this wholesale price reduction is more than offset by the need for significantly higher RES support to ensure that the same decarbonisation target is met.
- A lower carbon price would increase the utilisation rate of coal power plants by 15% in 2030 and 20% in 2045. However, the lower carbon price does not prevent coal from being priced out of the market by 2050.
- Gas utilisation rates fall with lower carbon prices.
- Change in demand has a limited impact on coal based generation, but RES capacity and generation, notably wind, are more sensitive.
- Lower hydro and wind potential results in slightly increased PV capacity and generation and a small role for natural gas in 2050, in contrast to the 'decarbonisation' scenario.

## 5.6 Network

Serbia's transmission system is already well-connected with neighbouring countries. In the future, additional network investments are expected to accommodate higher RES integration and cross-border electricity trade and to account for significant growth in peak load. Serbia is planning a new 400 kV line with Bosnia and Herzegovina and Montenegro, which would help the country to further increase trade not only with these countries, but within the whole region. The recorded peak load for Serbia in 2016 was 5775 MW (ENTSO-E DataBase) and it is projected to be 6392 MW in 2030 (SECI DataBase) and 7579 MW in 2050. Consequently, high and medium voltage domestic transmission and distribution lines will need investment.

For the comparative assessment, a 'base case' network scenario was constructed according to the SECI baseline topology and trade flow assumptions, and the network effect of the higher RES deployment futures ('delayed' and 'decarbonisation' scenarios) were compared to this 'base case' scenario.

The network analysis covered the following ENTSO-E impact categories:

- **Contingency analysis:** Analysis of the network constraints anticipates several contingencies in Serbia's cross-border network. They can be overcome with moderate investments in the transmission network, some 29 mEUR in 2030 and 52 mEUR in 2050. The following table illustrates the transmission network elements where problems are identified for the future, and also the possible solutions to the arising problems.

**TABLE 1 | OVERLOADINGS IN THE SERBIAN SYSTEM, 2030 AND 2050**

| Scenario | Trippings | Overloading | Solution | Units (km or pcs) | Cost m€ |
|---|---|---|---|---|---|
| Delayed 2030 | Several contingencies | OHL 110 kV Alibunar – Pancevo (RS) | New OHL 110 kV Bela Crkva – Veliko Gradiste | 35 | 2.8 |
| | OHLs 110 kV WPP Bela Anta – WPP Alibunar, or WPP Bela Anta – WPP Košava (RS) | WPP Bela Anta – WPP Košava, or OHLs 110 kV WPP Bela Anta – WPP Alibunar (RS) | Reconstruction of the OHL from 150 mm$^2$ to 240/40 mm$^2$ | 65 | 6.5 |
| Decarbon 2030 | OHLs 110 kV WPP Bela Anta – WPP Alibunar, or WPP Bela Anta – WPP Košava (RS) | WPP Bela Anta – WPP Košava, or OHLs 110 kV WPP Bela Anta – WPP Alibunar | Reconstruction of the OHLs in the area of RESs from 150 mm$^2$ to 390/65 mm$^2$ | 65 | 8.5 |
| | Several contingencies | OHL 110 kV Alibunar – Pancevo | New OHL 110 kV Bela Crkva – Veliko Gradiste | 35 | 2.8 |
| | OHLs 110 kV WPP Bela Anta – WPP Alibunar, or WPP Bela Anta – WPP Košava (RS) | WPP Bela Anta – WPP Košava, or OHLs 110 kV WPP Bela Anta – WPP Alibunar | Reconstruction of the OHLs in the area of RESs from 150 mm$^2$ to 390/65 mm$^2$ | 65 | 8.5 |
| Delayed 2050 | OHL 400 kV RP Drmno (RS) – Smederevo (RS) | OHL 400 kV Pancevo (RS) – Beograd (RS) | Change of the Conductors and earthwires & OPGW across the Danube river with higher capacity (1km) | 1 | 0.08 |
| Decarbon 2050 | Several contingencies | several overloadings in 110 kV network close to RESs | SS 400/110 kV Belgrade West (part of it is related to RES integration) | 1 | 20 |
| | OHL 400 kV RP Drmno (RS) – Smederevo(RS) | OHL 400 kV Pancevo (RS) – Beograd (RS) | Change of the Conductors and earthwires & OPGW across the Danube river with higher capacity (1km) | 1 | 0.08 |
| | OHL 400 kV Nis (RS) – Sofia (BG) | OHL 400 kV Stip (MK) – Ch Mogila (BG) | OHL Double Circuit 400 kV Nis (RS) – Sofia (BG) 2$^{nd}$ line Due to large RESs scaling in Greece and large import of Serbia | 90 | 31 |
| | OHL 400 kV Djerdap (RS) – Portile de Fier (RO) | OHL 400 kV Nis (RS) – Sofia (BG) | OHL Double circuit 400 kV Djerdap (RS) – Portile de Fier (RO) 2$^{nd}$ line Due to large RESs scaling in Romania and Greece and large import of Serbia | 2 | 0.7 |

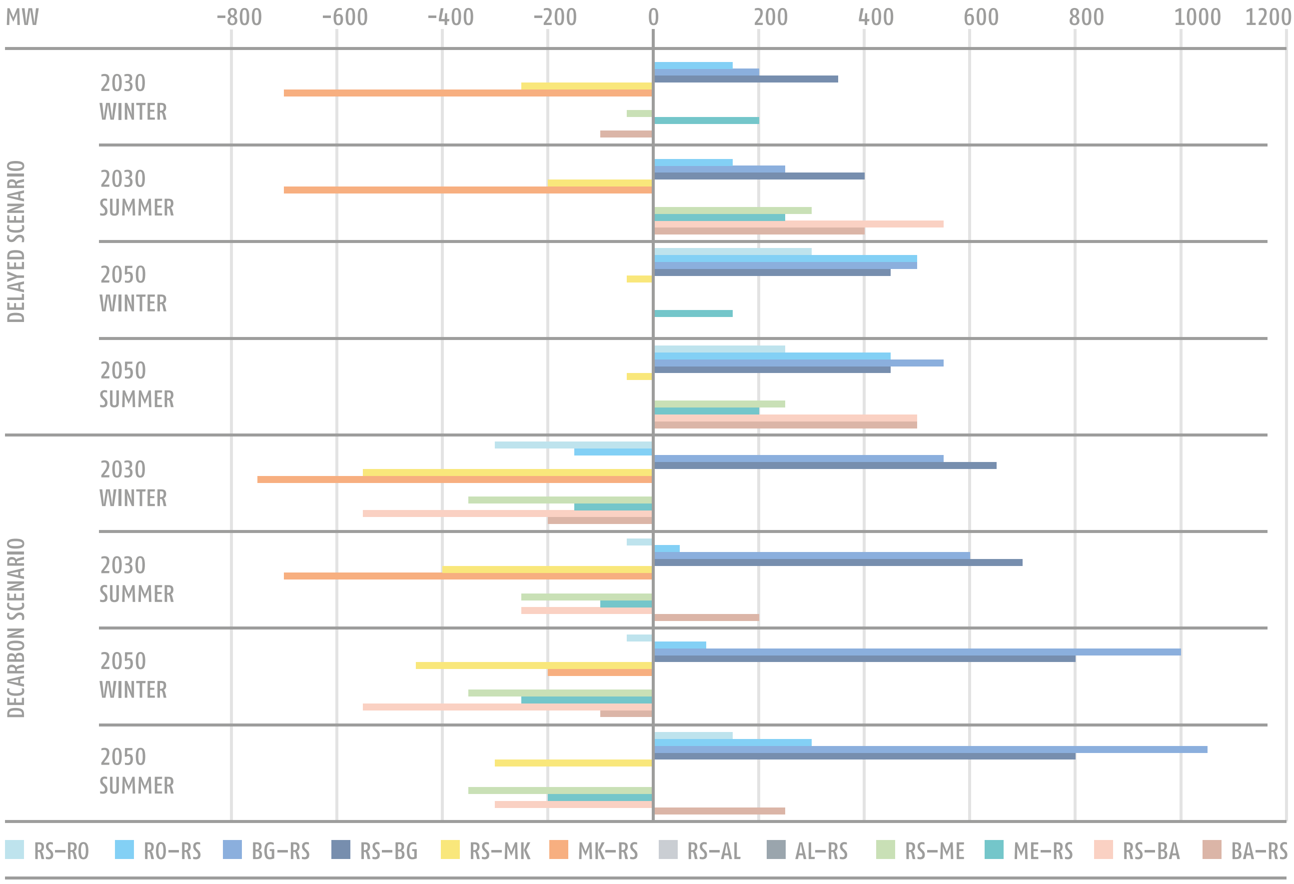



**FIGURE 14**
NTC VALUE CHANGES IN 2030 AND 2050 IN THE 'DELAYED' AND 'DECARBONISATION' SCENARIOS COMPARED TO THE 'BASE CASE' SCENARIO

- **TTC and NTC assessment:** Total and Net Transfer Capacity (TTC/NTC) changes were evaluated between Serbia and bordering countries relative to the 'base case' scenario. The production pattern (including the production level and its geographic distribution) and load pattern (load level and its geographical distribution, the latter of which is not known) have significant influence on NTC values between Serbian and neighbouring electricity systems. Figure 14 depicts the changes in NTC values for 2030 and 2050, revealing two opposing forces from higher RES deployment. First, the high concentration of RES in a geographic area may cause congestion in the transmission network, reducing NTCs and requiring further investment. Second, if RES generation replaces imported electricity it may increase NTC for a given direction.

  As the results show, no clear trend in NTC values could be determined in the 'delayed' and 'decarbonisation' scenarios. While NTC values mostly rise in the 2030 period in both scenarios, the RS-MK direction is negative. By 2050 the general NTC pattern is negative in most directions, however the BG-RS direction shows a positive change in the NTC between the two countries.

- **Network losses:** Transmission network losses are affected in different ways. For one, losses are reduced as renewables, especially PV, are mostly connected to the distribution network. At the same time, high levels of electricity trade projected in 2050 will increase transmission network losses. Figure 15 shows that in the 'decarbonisation' and 'delayed' scenarios transmission losses decrease significantly compared to the 'base case' scenario

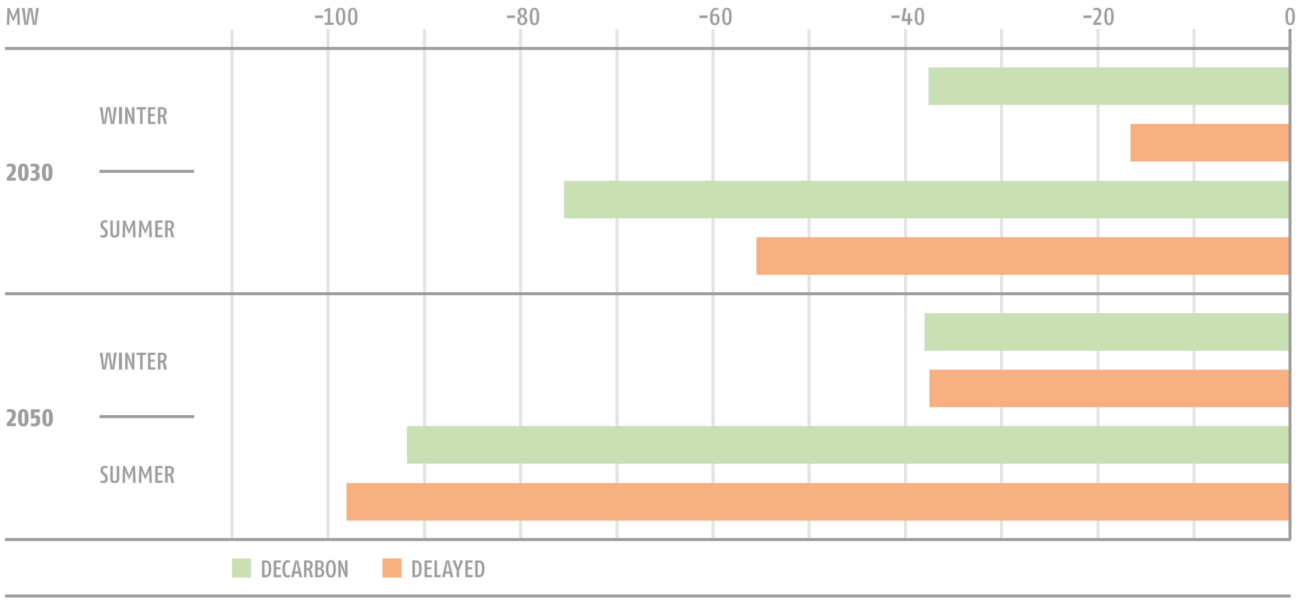



**FIGURE 15**
LOSS VARIATION COMPARED TO THE BASE CASE IN THE 'DELAYED' AND 'DECARBONISATION' SCENARIOS (MW, NEGATIVE VALUES INDICATE LOSS REDUCTION)

As figure 15 illustrates, higher RES deployment reduces transmission losses by close to 20 MW in 2030 but has a limited impact in 2050 for the modelled hours in both scenarios. This represents a 93 GWh loss variation in 2030 and a more limited impact in 2050.

Overall, moderate investment in the transmission and distribution network is needed to accommodate new RES capacities in Serbia's electricity system compared to the RES generation investment needs. It has to be emphasised, that these estimates only include investments in the transmission network (both domestic and cross-border), but not the in distribution where significant developments are needed to accommodate the penetration of distributed RES generation.

## 5.7 Macroeconomic impacts

A 'baseline' scenario differing from the three core scenarios was constructed for the macroeconomic analysis to serve as a basis for comparison, whereby only power plants with a final investment decision by 2016 are built, investment rates in the sector remain unchanged for the remaining period, no 'decarbonisation' targets are set and no additional renewable support is included beyond existing policies. The 'baseline' scenario assumes lower levels of investment than the three core scenarios.

The 'baseline' scenario for Serbia envisages initial robust GDP growth based on a strong credit recovery after the financial crisis, followed by a slowdown as Serbia approaches EU average levels. Starting above 3% per annum, economic growth is expected to slow down to 1.5% by 2046-2050. Gross government debt could decline to 60% of GDP, while gross external debt could reach 50% of GDP.

The ratio of household electricity expenditure to income is 5.4%, the highest in the region, and projected to increase further to around 7% by 2050. This reflects an increase in electricity prices, but the effect of this increase on household expenditure is dampened by a significant increase in household income growth.

All three core scenarios imply a moderate increase in investment compared to the 'baseline' scenario as even in the most intensive periods the additional investment is at most 1% of GDP. Contrary to most other countries in the SEERMAP region, the 'no target' scenario requires the same absolute level of investment effort as the 'decarbonisation'


**FIGURE 16**
GDP AND EMPLOYMENT IMPACTS COMPARED WITH THE 'BASELINE' SCENARIO

scenario. However, due to the different timing of the investments, corresponding to different GDP levels, the relative level of investment reaches 0.8% of GDP in the 2021-2025 period for the 'no target' scenario, which is higher than the 0.4% level in the 'decarbonisation' scenario. Nonetheless, the 'decarbonisation' scenario has a more persistent investment profile than the 'no target' scenario. The 'delayed' scenario shows the biggest investment effort at 1% of GDP in the 2021-2025 period, with another milder investment peak in the 2036-2050 period.

The macroeconomic results were evaluated along three dimensions: macroeconomic gain, macroeconomic vulnerability and affordability. Macroeconomic gain explains the extent to which the scenarios contribute to greater overall economic activity, measured by GDP and employment across two time dimensions. First, the average difference over the whole time horizon (2016-2050) is compared with the baseline. Then the long term effect is determined by the deviation from the baseline in the period 2046-2050. It is important to note that because the population remains the same across scenarios GDP gains also reflect GDP per capita effects.

The overall results for Serbia suggest limited macroeconomic gains from the three core scenarios. In the 'decarbonisation' scenario the GDP level could be 0.6% higher on average until 2050 compared to the 'baseline' scenario, with a higher long term GDP effect of 1.5%. Gains are much more significant in the 'delayed' scenario, at around 2.6% on average and 4.5% over the long term. The 'no target' scenario also contains somewhat higher macroeconomic gains than the 'decarbonisation' scenario at 1.6% and 2% of GDP respectively. Employment effects are muted, well below 1% compared to the 'baseline' scenario in the 'decarbonisation' and 'delayed' scenarios on average over the whole period, while these effects disappear in the long term. There is virtually no employment impact from the 'no target' scenario over the entire period on average.

Long term GDP gains in the 'decarbonisation' and 'delayed' scenarios emerge from two sources. The additional investment raises the level of productive capital in the economy and the newly installed, mostly foreign technologies increase overall productivity. The lower employment gains compared to the GDP effect are explained by two factors: (i) the energy investments are relatively capital intensive and (ii) the initial

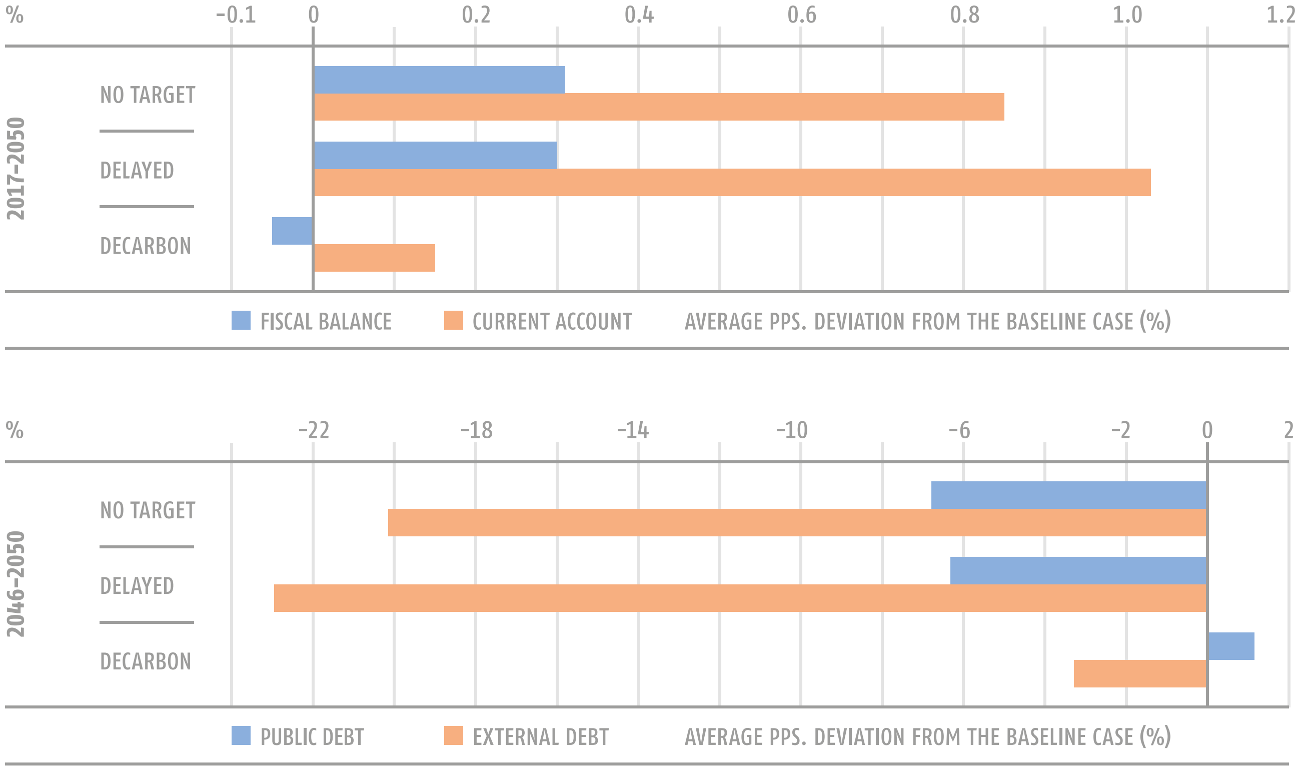



**FIGURE 17**
PUBLIC AND EXTERNAL BALANCES AND DEBT IMPACTS COMPARED WITH THE 'BASELINE' SCENARIO

employment gains are translated into higher wages in the longer term, as labour supply remains the same across scenarios.

The macroeconomic vulnerability calculation captures how the additional investments contribute to the sustainability of the fiscal and external positions of the country measured by the fiscal and external balances and the public and external debt indicators. While the fiscal and external balances are compared to the 'baseline' scenario over the whole projection horizon (2017-2050), the debt indicators focus on the long term effects, with the difference from the baseline only calculated at the end of the modelled period. This approach is consistent with the fact that debt is accumulated from past imbalances.

The three core scenarios mostly decrease the macroeconomic vulnerability of Serbia. External debt declines by around 20% of GDP in the long term in the 'no target' and 'delayed' scenarios, and remains roughly unchanged in the 'decarbonisation' scenario. These results primary reflect the fact that net energy imports (in particular electricity) improve in the 'delayed' and 'no target' scenarios compared with the 'baseline' scenario, while net imports deteriorate in the 'decarbonisation' scenario. In the 'delayed' and 'no target' scenarios the fiscal balance improves and public debt declines from higher $CO_2$ auction revenues and higher GDP. At the same time lower $CO_2$ revenues result in a deterioration of the budgetary position in the 'decarbonisation' scenario.

Affordability measures the burden of the electricity bill for households as the ratio of household electricity expenditure to household disposable income. The indicator is tracked closely throughout the whole period in order to identify notable increases.

There is no significant change in affordability in the core scenarios compared to the 'baseline' scenario, with moderate deterioration characterizing all scenarios. There are two notable exceptions. Household affordability deteriorates by close to 20% at the

**FIGURE 18**
HOUSEHOLD ELECTRICITY EXPENDITURE 2017-2050


end of the 'delayed' scenario due to higher RES support overcoming the decrease in real wholesale electricity prices. A decrease in electricity prices characterises the 'decarbonisation' scenario, leading to a 10% decline in household electricity expenditure at the end of the projection horizon.

# 6 | Policy conclusions

The SEERMAP project modelling identifies some key findings with respect to the different strategic choices in the electricity sector that Serbia can pursue. We review these findings and suggest some policy insights. **The analysis has uncovered robust findings relevant for all scenarios, based on which no regret policy options can be identified.**

MAIN POLICY CONCLUSIONS

**Regardless of whether Serbia pursues an active policy to decarbonise its electricity sector a significant shift from fossil fuels to renewables will take place:**

- Due to aging power plants Serbia will need to replace all of its existing fossil fuel generation fleet by 2050;

- Lignite electricity generation will comprise around 5% or less electricity generation by 2050, with most of the remaining electricity generation coming from renewables;
- The high penetration of RES across all scenarios suggests that Serbia's energy policy should focus on enabling RES integration;

**Decarbonisation has benefits:**

- Current policies and trends are not in line with the deep electricity sector decarbonisation share of 93-99%envisioned in the EU Roadmap 2050;
- The 'decarbonisation' scenario demonstrates that it is technically feasible and financially viable for Serbia to reduce its emissions to zero in the electricity sector by 2050;
- Decarbonisation does not drive up wholesale prices relative to other scenarios with less ambitious RES policies, and actually reduces them after 2045;
- Decarbonisation will not require additional investment in generation capacity compared to a scenario with no emission reduction target;
- The required RES support needed to achieve total decarbonisation will be low, in the range of 0.7-2.1 EUR/MWh throughout the period until 2050;
- Implementation of a long term decarbonisation strategy reduces the cost of stranded investments in fossil fuel capacities by close to 100%, from 1033 mEUR to 7 mEUR.

**However, there are trade-offs:**

- Although Serbia is a significant net importer of electricity under all scenarios, net imports are higher under a 'decarbonisation' scenario before 2050;
- The macroeconomic analysis shows that due to a lower investment shock in the 'decarbonisation' scenario compared with other scenarios, GDP growth and employment will not be positively impacted.

## 6.1 Main electricity system trends

The main investment challenge in Serbia concerns currently installed lignite capacities. Approximately 55% of current fossil fuel generation capacity, more than 2400 MW, is expected to be decommissioned by the end of 2035 and the rest by 2050. This provides both a challenge in terms of the need to ensure a policy framework which will result in the necessary new investment, but also an opportunity to shape the electricity sector over the long term without being constrained by the current capacity mix.

**Whether or not Serbia pursues an active policy to support renewable electricity generation, fossil fuel generation capacity will decline precipitously. Driven by the price of carbon, coal and lignite generation is 5% or lower under all scenarios by 2050.** The decline in the share of these fuels begins much earlier, as the carbon price begins to affect Serbia in 2030.

With ambitious decarbonisation targets and corresponding RES support schemes, Serbia will have an electricity mix with 63% renewable generation as a share of consumption, and 100% as a share of electricity generation. The RES capacities with the highest growth from current levels are wind and solar. Hydro continues to play a role, increasing its capacity by 60% by 2050 from current levels. Absent a $CO_2$ emission reduction target and with renewable subsidies phased out under the 'no target' scenario, the share of RES in 2050 in electricity consumption will reach slightly more than 50%, equivalent to almost 90% as a share of electricity generation.

**The high penetration of RES in all scenarios suggests that a robust no-regret action for Serbian energy policy is to focus on enabling RES integration.** This involves:

- investing in transmission and distribution networks,
- enabling demand side management and RES production through a combination of technical solutions and appropriate regulatory practices, and
- promoting investment in storage solutions including hydro and small scale storage.

Natural gas will not play a significant role in electricity generation in any scenario, but is particularly low in the scenarios with a decarbonisation target.

**Delayed action in the rollout of renewables is feasible but carries two significant disadvantages compared with a long term planned effort. It results in stranded fossil fuel generation assets,** including currently planned power plants. Translated into a price equivalent over a 10 year period, the cost of stranded assets is higher than the RES support needed for decarbonising the electricity sector. Assuming delayed action, **the disproportionate push towards the end of the modelled period to meet the $CO_2$ emission reduction target requires significantly more RES support.**

## 6.2 Security of supply

The **high level of net imports is a robust finding across all scenarios.** Under the modelled market conditions, Serbia is not expected to have a comparative advantage in electricity generation with respect to any of the generation technologies. Coal will not be competitive under projected carbon prices, and RES potential in Serbia is relatively low in comparison to other countries in the region. With highly interconnected infrastructure in the region, small price differences across borders imply that in a competitive interconnected market electricity will be produced where it is cheapest. Policy tools which could provide a competitive advantage to domestic generation are largely absent in a competitive market and incompatible with EU state aid rules. Therefore, **Serbia needs to prepare for an electricity market where it will be a net importer over the long term.** Short term measures (such as investment in lignite capacities) can be pursued, but only offer temporary relief and likely result in stranded costs.

In order to address intermittency of a significant share of the installed generation capacity, Serbia could work on the no regret measures discussed above to enable a high share of RES penetration without compromising security of supply, involving demand side measures, increased network connections and storage solutions.

Serbia has a negative generation adequacy margin across all scenarios from 2035 onwards and for the entire modelling period under the 'decarbonisation' scenario. However, this is the cost optimal solution. Increasing the adequacy margin to zero would require reserve capacity costs of more than 200 mEUR/year in 2050 under the 'decarbonisation' scenario, but is also high in periods of other scenarios, especially during the second half of the modelled time period.

The network modelling results suggest that required network investments in transmission and cross border capacities are moderate. Several possible contingencies in the transmission network within the country and with the neighbouring connections are identified for 2030 and 2050, but costs of resolving these issues do not exceed 52 mEUR beyond those listed in ENTSO-E TYNDP 2016.

## 6.3 Sustainability

**Serbia has relatively low renewable potential, especially solar and wind, compared with the SEE regional average** and its contribution to the 2050 emission reduction target is therefore below average. Despite this, $CO_2$ emissions in the electricity sector fall by 100% in the 'decarbonisation' and around 94% in the 'no target' and 'delayed' scenarios. The reason for this is that coal is priced out of the market due to the increasing carbon price, and Serbia relies on electricity imports in all scenarios in almost all years, with a very significant net import share during the end of the modelled time horizon.

In order to realise its RES potential, policies eliminating barriers to RES investment are important. **A no-regret step involves de-risking policies addressing the high cost of capital.** This would allow for cost-efficient renewable energy investment.

## 6.4 Affordability and competitiveness

**Decarbonising the electricity sector does not drive up wholesale electricity prices compared to scenarios without a reduction target.** The wholesale price of electricity is not driven by the level of decarbonisation but by the $CO_2$ price, which is applied across all scenarios, and the price of natural gas, because the latter is the marginal production (within the region) needed to meet demand in a significant number of hours of the year for much of the modelled time period in all scenarios.

The wholesale price of electricity follows a similar trajectory under all scenarios and only diverges after 2045, when wholesale electricity prices fall due to a high share of low marginal cost RES in the electricity mix in the two scenarios with a decarbonisation target.

**All scenarios demonstrate a significant increase in the wholesale electricity price compared with current (albeit historically low) price levels.** This trend is observable across the SEE region and the EU as a whole in all scenarios for the modelled time period, driven by the price of carbon and natural gas, both of which increase significantly by 2050. While higher wholesale prices will reach end consumers, it is an important signal attracting investment to replace retiring capacity. **The macroeconomic analysis shows that despite the high absolute increase in wholesale prices, household electricity expenditure relative to household income is expected to increase only slightly in all scenarios due to gains in household disposable income.**

**Contrary to findings in other countries within the region, decarbonisation will not require more investment in generation capacity.** However, the generation capacity mix will change, as will the financial profile of investments. **These investments are assumed to be financed by private actors** who accept higher investment costs in exchange for low operation (including fuel) and maintenance costs. With no increase in overall investment in generation capacity in the 'decarbonisation' scenario, the usual benefits associated with RES investment in terms of increased GDP and employment are absent.

Although not modelled, **wholesale price volatility is also expected to increase** as a result of a higher share of intermittent renewables. **Demand and supply side measures can reduce price volatility.** Governments will need to determine the acceptable level of price volatility in relation to the costs of supply and demand side measures and decide on appropriate policy measures.

High initial investment needs of RES technologies are extremely sensitive to the cost of capital, which is especially high in Serbia compared with far lower values in Western European member states. Although much of the value of the cost of capital depends on the country risk profile linked to the general macroeconomic performance of a given country, **policymakers can reduce the cost of capital through interventions by ensuring a stable energy policy framework and establishing de-risking measures. These should be considered to be no-regret steps because they minimise system cost and consumer expenditures.**

**Electricity decarbonisation consistent with EU targets requires continued RES support during the entire period until 2050 under all scenarios.** However, the need for support is capped by increasing electricity wholesale prices that incentivise significant RES investment even without support. A potentially significant share of the RES support can be covered from EU ETS revenues after 2031, thereby lowering the burden to consumers. **The need for long term RES support highlights the need for long term evidence based policy planning,** to provide investors with the necessary stability to ensure that sufficient renewable investments will take place. However, the absolute level of RES support required in Serbia is low.

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# Annexes

# Annex 1 | Model output tables

## TABLE A1 | 'NO TARGET' SCENARIO

| | | | 2016 | 2020 | 2025 | 2030 | 2035 | 2040 | 2045 | 2050 |
|---|---|---|---|---|---|---|---|---|---|---|
| Installed capacity, MW | Coal, lignite | Existing | 4 351 | 4 112 | 4 012 | 4 012 | 1 937 | 697 | 349 | 0 |
| | | New | 0 | 0 | 700 | 1 400 | 1 400 | 1 400 | 1 400 | 1 400 |
| | Natural gas | Existing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | | New | 0 | 488 | 488 | 488 | 488 | 888 | 888 | 400 |
| | Nuclear | Existing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | | New | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | HFO/LFO | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Hydro | | 3 070 | 3 247 | 3 559 | 3 968 | 4 401 | 4 797 | 4 924 | 5 031 |
| | Wind | | 11 | 48 | 48 | 47 | 75 | 127 | 841 | 2 656 |
| | Solar | | 3 | 51 | 51 | 51 | 86 | 183 | 431 | 946 |
| | Other RES | | 11 | 34 | 42 | 50 | 83 | 118 | 191 | 298 |
| Gross consumption, GWh | | | 34 422 | 36 844 | 38 920 | 40 961 | 42 994 | 45 523 | 47 221 | 48 796 |
| Net electricity generation, GWh | Total | | 29 188 | 31 086 | 38 325 | 37 561 | 29 356 | 30 955 | 33 268 | 27 627 |
| | Coal and lignite | | 19 819 | 18 731 | 23 365 | 24 319 | 14 804 | 12 049 | 10 013 | 1 528 |
| | Natural gas | | 17 | 2 222 | 3 847 | 794 | 482 | 3 224 | 4 490 | 1 406 |
| | Nuclear | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | HFO/LFO | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Hydro | | 9 236 | 9 842 | 10 790 | 12 097 | 13 493 | 14 753 | 15 666 | 16 506 |
| | Wind | | 31 | 109 | 109 | 106 | 172 | 289 | 1 919 | 6 057 |
| | Solar | | 22 | 51 | 51 | 51 | 87 | 184 | 434 | 952 |
| | Other RES | | 62 | 131 | 163 | 193 | 319 | 457 | 746 | 1 178 |
| Net import, GWh | Total | | 5 234 | 5 758 | 595 | 3 400 | 13 638 | 14 567 | 13 952 | 21 169 |
| | BA_SRP | | 798 | 3 874 | 2 763 | 3 766 | 4 186 | 6 748 | 2 408 | 1 848 |
| | BG | | 2 341 | 1 859 | 1 078 | 731 | 4 652 | -1 635 | -1 969 | -2 097 |
| | HR | | 830 | 965 | -71 | 3 364 | 4 799 | 9 051 | 5 759 | 3 770 |
| | HU | | 1 539 | 547 | -797 | 3 340 | 2 641 | 4 980 | 4 067 | 4 567 |
| | MK | | -1 500 | -1 003 | 214 | -1 286 | -673 | -858 | -756 | -417 |
| | ME | | 440 | -1 270 | -4 017 | -6 697 | -2 523 | -3 834 | -5 560 | 549 |
| | RO | | 968 | 581 | -171 | 1 305 | 1 020 | 2 775 | 9 226 | 11 561 |
| | KO | | -182 | 205 | 1 596 | -1 122 | -465 | -2 660 | 777 | 1 388 |
| Net import ratio, % | | | 15.2% | 15.6% | 1.5% | 8.3% | 31.7% | 32.0% | 29.5% | 43.4% |
| RES-E share (RES-E production/gross consumption, %) | | | 27.2% | 27.5% | 28.6% | 30.4% | 32.7% | 34.5% | 39.7% | 50.6% |
| Utilisation rates of RES-E technical potential, % | Hydro | | na | na | na | na | na | na | na | 73% |
| | Wind | | na | na | na | na | na | na | na | 36% |
| | Solar | | na | na | na | na | na | na | na | 14% |
| Utilisation rates of conventional power production, % | Coal and lignite | | 52.0% | 52.0% | 56.6% | 51.3% | 50.6% | 65.6% | 65.4% | 12.5% |
| | Natural gas | | na | 52.0% | 90.0% | 18.6% | 11.3% | 41.4% | 57.7% | 40.1% |
| | Nuclear | | na | na | na | na | na | na | na | na |
| Natural gas consumption of power generation, TWh | | | 0.03 | 4.04 | 6.99 | 1.44 | 0.88 | 5.54 | 7.79 | 2.38 |
| Security of supply | Generation adequacy margin | | -2% | 0% | 7% | 17% | -10% | -16% | -20% | -21% |
| | System adequacy margin | | 76% | 74% | 119% | 137% | 143% | 137% | 121% | 112% |
| $CO_2$ emission | Emission, Mt $CO_2$ | | 23.9 | 23.3 | 28.3 | 26.9 | 15.4 | 13.1 | 11.4 | 2.0 |
| | $CO_2$ emission reduction compared to 1990, % | | 26.9% | 28.7% | 13.4% | 17.5% | 52.8% | 59.8% | 65.2% | 94.0% |
| Spreads | Clean dark spread, €(2015)/MWh | | 25.4 | 30.8 | 42.8 | 14.7 | 13.5 | 13.9 | 6.5 | -13.6 |
| | Clean spark spread, €(2015)/MWh | | -2.9 | -0.5 | 5.3 | -5.2 | -4.6 | -5.7 | -2.7 | -10.9 |
| Price impacts | Electricity wholesale price, €(2015)/MWh | | 34.7 | 41.0 | 52.8 | 60.2 | 68.4 | 77.7 | 90.5 | 90.5 |
| | Total RES-E support/gross consumption, €(2015)/MWh, five year average | | na | 1.1 | 0.9 | 0.3 | 0 | 0 | 0 | 0 |
| | Revenue from $CO_2$ auction/gross consumption, €(2015)/MWh | | 0 | 0 | 0 | 22.0 | 15.0 | 14.4 | 16.6 | 3.5 |
| Investment cost, m€/5 year period | Coal and lignite | | na | 0 | 1 801 | 1 757 | 0 | 0 | 0 | 0 |
| | Natural gas | | na | 450 | 0 | 0 | 0 | 365 | 0 | 0 |
| | Total Fossil | | na | 450 | 1 801 | 1 757 | 0 | 365 | 0 | 0 |
| | Total RES-E | | na | 363 | 342 | 529 | 733 | 835 | 1 596 | 2 967 |
| | Total | | na | 813 | 2 144 | 2 286 | 733 | 1 201 | 1 596 | 2 967 |
| Main assumptions | Coal price, €(2015)/GJ | | 1.78 | 1.95 | 1.93 | 1.89 | 1.98 | 2.04 | 2.04 | 2.04 |
| | Lignite price, €(2015)/GJ | | 0.98 | 1.07 | 1.06 | 1.04 | 1.09 | 1.12 | 1.12 | 1.12 |
| | Natural gas price, €(2015)/MWh | | 18.79 | 20.74 | 23.78 | 25.98 | 28.07 | 31.64 | 32.72 | 33.00 |
| | $CO_2$ price, €(2015)/t | | 8.60 | 15.00 | 22.50 | 33.50 | 42.00 | 50.00 | 69.00 | 88.00 |

## TABLE A2 | 'DELAYED' SCENARIO

| | | | 2016 | 2020 | 2025 | 2030 | 2035 | 2040 | 2045 | 2050 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Installed capacity, MW** | Coal, lignite | Existing | 4 351 | 4 112 | 4 012 | 4 012 | 1 937 | 697 | 349 | 0 |
| | | New | 0 | 0 | 700 | 1 400 | 1 400 | 1 400 | 1 400 | 1 400 |
| | Natural gas | Existing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | | New | 0 | 488 | 488 | 488 | 488 | 488 | 488 | 0 |
| | Nuclear | Existing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | | New | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | HFO/LFO | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Hydro | | 3 070 | 3 247 | 3 619 | 4 066 | 4 534 | 4 935 | 5 064 | 5 157 |
| | Wind | | 11 | 48 | 426 | 439 | 454 | 1 201 | 3 360 | 6 721 |
| | Solar | | 3 | 51 | 121 | 143 | 387 | 954 | 1 989 | 3 143 |
| | Other RES | | 11 | 34 | 61 | 74 | 93 | 154 | 252 | 396 |
| **Gross consumption, GWh** | | | 34 422 | 36 845 | 38 944 | 40 977 | 43 013 | 45 019 | 46 764 | 48 604 |
| **Net electricity generation, GWh** | Total | | 29 188 | 31 056 | 39 454 | 35 454 | 29 844 | 31 944 | 34 588 | 38 899 |
| | Coal and lignite | | 19 819 | 18 731 | 23 365 | 21 063 | 13 758 | 11 443 | 6 644 | 1 851 |
| | Natural gas | | 17 | 2 191 | 3 742 | 489 | 304 | 922 | 1 071 | 0 |
| | Nuclear | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | HFO/LFO | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Hydro | | 9 236 | 9 842 | 11 013 | 12 463 | 13 990 | 15 271 | 16 190 | 16 954 |
| | Wind | | 31 | 109 | 971 | 1 002 | 1 034 | 2 738 | 7 663 | 15 311 |
| | Solar | | 22 | 51 | 122 | 144 | 390 | 960 | 2 001 | 3 149 |
| | Other RES | | 62 | 131 | 242 | 293 | 367 | 611 | 1 018 | 1 634 |
| **Net import, GWh** | Total | | 5 234 | 5 789 | -510 | 5 524 | 13 168 | 13 075 | 12 176 | 9 705 |
| | BA_SRP | | 1 262 | 3 708 | 3 796 | 5 540 | 6 232 | 6 957 | 3 384 | 1 167 |
| | BG | | 2 122 | 1 828 | 918 | 120 | -1 795 | -3 838 | -1 911 | -2 549 |
| | HR | | 1 318 | 1 462 | -341 | 5 925 | 7 455 | 8 120 | 3 344 | 1 710 |
| | HU | | 989 | 174 | -1 612 | 1 829 | 3 853 | 2 383 | 214 | -439 |
| | MK | | -1 395 | -898 | -21 | -1 137 | -1 001 | -137 | 503 | 425 |
| | ME | | 186 | -987 | -3 042 | -1 274 | 4 827 | 2 234 | 252 | 3 250 |
| | RO | | 1 116 | 614 | -1 827 | -2 928 | -5 366 | -3 616 | -609 | -3 947 |
| | KO | | -363 | -113 | 1 619 | -2 552 | -1 038 | 973 | 6 999 | 10 089 |
| **Net import ratio, %** | | | 15.2% | 15.7% | -1.3% | 13.5% | 30.6% | 29.0% | 26.0% | 20.0% |
| **RES-E share (RES-E production/gross consumption, %)** | | | 27.2% | 27.5% | 31.7% | 33.9% | 36.7% | 43.5% | 57.5% | 76.2% |
| **Utilisation rates of RES-E technical potential, %** | Hydro | | na | na | na | na | na | na | na | 75% |
| | Wind | | na | na | na | na | na | na | na | 92% |
| | Solar | | na | na | na | na | na | na | na | 48% |
| **Utilisation rates of conventional power production, %** | Coal and lignite | | 52.0% | 52.0% | 56.6% | 44.4% | 47.1% | 62.3% | 43.4% | 15.1% |
| | Natural gas | | na | 51.3% | 87.6% | 11.4% | 7.1% | 21.6% | 25.1% | na |
| | Nuclear | | na | na | na | na | na | na | na | na |
| **Natural gas consumption of power generation, TWh** | | | 0.03 | 3.98 | 6.80 | 0.89 | 0.55 | 1.68 | 1.95 | – |
| **Security of supply** | Generation adequacy margin | | -2% | 0% | 10% | 20% | -7% | -17% | -15% | -21% |
| | System adequacy margin | | 76% | 74% | 120% | 139% | 145% | 133% | 129% | 130% |
| **$CO_2$ emission** | Emission, Mt $CO_2$ | | 23.9 | 23.2 | 28.2 | 22.9 | 14.1 | 11.7 | 6.9 | 1.8 |
| | $CO_2$ emission reduction compared to 1990, % | | 26.9% | 28.8% | 13.5% | 29.8% | 56.7% | 64.1% | 78.9% | 94.5% |
| **Spreads** | Clean dark spread, €(2015)/MWh | | 25.4 | 30.8 | 40.6 | 13.4 | 12.0 | 16.2 | 3.7 | -31.2 |
| | Clean spark spread, €(2015)/MWh | | -2.9 | -0.5 | 3.1 | -6.6 | -6.1 | -3.4 | -5.6 | -28.4 |
| **Price impacts** | Electricity wholesale price, €(2015)/MWh | | 34.7 | 41.0 | 50.7 | 58.8 | 67.0 | 79.9 | 87.6 | 72.9 |
| | Total RES-E support/gross consumption, €(2015)/MWh, five year average | | na | 1.1 | 2.3 | 0.6 | 0.8 | 1.8 | 2.8 | 18.6 |
| | Revenue from $CO_2$ auction/gross consumption, €(2015)/MWh | | 0 | 0 | 0 | 18.7 | 13.8 | 13.0 | 10.2 | 3.3 |
| **Investment cost, m€/5 year period** | Coal and lignite | | na | 0 | 1 801 | 1 757 | 0 | 0 | 0 | 0 |
| | Natural gas | | na | 450 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Total Fossil | | na | 450 | 1 801 | 1 757 | 0 | 0 | 0 | 0 |
| | Total RES-E | | na | 363 | 956 | 590 | 880 | 1 934 | 4 047 | 4 951 |
| | Total | | na | 813 | 2 758 | 2 347 | 880 | 1 934 | 4 047 | 4 951 |
| **Main assumptions** | Coal price, €(2015)/GJ | | 1.78 | 1.95 | 1.93 | 1.89 | 1.98 | 2.04 | 2.04 | 2.04 |
| | Lignite price, €(2015)/GJ | | 0.98 | 1.07 | 1.06 | 1.04 | 1.09 | 1.12 | 1.12 | 1.12 |
| | Natural gas price, €(2015)/MWh | | 18.79 | 20.74 | 23.78 | 25.98 | 28.07 | 31.64 | 32.72 | 33.00 |
| | $CO_2$ price, €(2015)/t | | 8.60 | 15.00 | 22.50 | 33.50 | 42.00 | 50.00 | 69.00 | 88.00 |

## TABLE A3 | 'DECARBONISATION' SCENARIO

| | | | 2016 | 2020 | 2025 | 2030 | 2035 | 2040 | 2045 | 2050 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Installed capacity, MW** | Coal, lignite | Existing | 4 351 | 4 112 | 4 012 | 4 012 | 1 937 | 697 | 349 | 0 |
| | | New | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Natural gas | Existing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | | New | 0 | 10 | 10 | 10 | 10 | 10 | 10 | 0 |
| | Nuclear | Existing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | | New | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | HFO/LFO | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Hydro | | 3 070 | 3 247 | 3 619 | 4 066 | 4 534 | 4 935 | 5 064 | 5 157 |
| | Wind | | 11 | 48 | 456 | 620 | 699 | 1 226 | 2 399 | 3 556 |
| | Solar | | 3 | 51 | 168 | 364 | 889 | 1 834 | 2 706 | 2 863 |
| | Other RES | | 11 | 34 | 74 | 120 | 193 | 305 | 448 | 594 |
| **Gross consumption, GWh** | | | 34 422 | 36 832 | 38 925 | 40 969 | 43 016 | 45 132 | 46 772 | 48 584 |
| **Net electricity generation, GWh** | Total | | 29 188 | 28 922 | 30 870 | 26 935 | 20 494 | 22 799 | 26 750 | 30 589 |
| | Coal and lignite | | 19 819 | 18 731 | 18 275 | 12 191 | 3 206 | 1 559 | 374 | 0 |
| | Natural gas | | 17 | 58 | 77 | 16 | 7 | 20 | 23 | 0 |
| | Nuclear | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | HFO/LFO | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Hydro | | 9 236 | 9 842 | 11 013 | 12 463 | 13 990 | 15 271 | 16 190 | 16 969 |
| | Wind | | 31 | 109 | 1 040 | 1 414 | 1 594 | 2 797 | 5 471 | 8 108 |
| | Solar | | 22 | 51 | 169 | 366 | 895 | 1 845 | 2 723 | 2 878 |
| | Other RES | | 62 | 131 | 296 | 484 | 803 | 1 307 | 1 969 | 2 634 |
| **Net import, GWh** | Total | | 5 234 | 7 910 | 8 055 | 14 034 | 22 522 | 22 333 | 20 022 | 17 995 |
| | BA_SRP | | 1 262 | 927 | 2 001 | 2 262 | 4 195 | 4 247 | 2 639 | 2 403 |
| | BG | | 2 122 | 2 385 | 1 731 | 1 088 | 2 973 | -125 | 1 189 | -236 |
| | HR | | 1 318 | 2 255 | 543 | 5 641 | 6 318 | 8 566 | 4 940 | 2 621 |
| | HU | | 989 | 3 218 | 1 710 | 2 919 | 3 753 | 3 674 | 1 936 | -551 |
| | MK | | -1 395 | -1 012 | -223 | -748 | -392 | -210 | -56 | 219 |
| | ME | | 186 | -2 113 | -2 166 | -27 | 3 519 | 2 683 | 4 228 | 5 983 |
| | RO | | 1 116 | 2 465 | 5 535 | 6 884 | 3 629 | 4 280 | 1 195 | 593 |
| | KO | | -363 | -216 | -1 076 | -3 985 | -1 473 | -784 | 3 950 | 6 964 |
| **Net import ratio, %** | | | 15.2% | 21.5% | 20.7% | 34.3% | 52.4% | 49.5% | 42.8% | 37.0% |
| **RES-E share (RES-E production/gross consumption, %)** | | | 27.2% | 27.5% | 32.2% | 35.9% | 40.2% | 47.0% | 56.3% | 63.0% |
| **Utilisation rates of RES-E technical potential, %** | Hydro | | na | na | na | na | na | na | na | 75% |
| | Wind | | na | na | na | na | na | na | na | 49% |
| | Solar | | na | na | na | na | na | na | na | 43% |
| **Utilisation rates of conventional power production, %** | Coal and lignite | | 52.0% | 52.0% | 52.0% | 34.7% | 18.9% | 25.5% | 12.3% | na |
| | Natural gas | | na | 66.5% | 88.5% | 18.3% | 7.6% | 23.4% | 26.5% | na |
| | Nuclear | | na | na | na | na | na | na | na | na |
| **Natural gas consumption of power generation, TWh** | | | 0.03 | 0.10 | 0.14 | 0 | 0.01 | 0.04 | 0.04 | – |
| **Security of supply** | Generation adequacy margin | | -2% | -8% | -7% | -5% | -30% | -40% | -39% | -39% |
| | System adequacy margin | | 76% | 66% | 103% | 114% | 122% | 112% | 104% | 98% |
| **$CO_2$ emission** | Emission, Mt $CO_2$ | | 23.9 | 22.5 | 21.9 | 14.4 | 3.7 | 1.8 | 0.4 | 0 |
| | $CO_2$ emission reduction compared to 1990, % | | 26.9% | 31.2% | 33.0% | 55.8% | 88.7% | 94.6% | 98.7% | 100.0% |
| **Spreads** | Clean dark spread, €(2015)/MWh | | 25.4 | 31.9 | 42.4 | 14.1 | 11.7 | 17.9 | 3.2 | -29.6 |
| | Clean spark spread, €(2015)/MWh | | -2.9 | 0.6 | 4.9 | -5.9 | -6.3 | -1.7 | -6.1 | -26.8 |
| **Price impacts** | Electricity wholesale price, €(2015)/MWh | | 34.7 | 42.1 | 52.4 | 59.5 | 66.7 | 81.7 | 87.1 | 74.5 |
| | Total RES-E support/gross consumption, €(2015)/MWh, five year average | | na | 1.1 | 2.0 | 2.1 | 2.0 | 1.5 | 0.7 | 0.7 |
| | Revenue from $CO_2$ auction/gross consumption, €(2015)/MWh | | 0 | 0 | 0 | 11.8 | 3.6 | 2.0 | 0.6 | 0 |
| **Investment cost, m€/5 year period** | Coal and lignite | | na | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Natural gas | | na | 9.1 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Total Fossil | | na | 9.1 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Total RES-E | | na | 337 | 1 095 | 951 | 1 317 | 1 894 | 3 275 | 2 694 |
| | Total | | na | 346 | 1 095 | 951 | 1 317 | 1 894 | 3 275 | 2 694 |
| **Main assumptions** | Coal price, €(2015)/GJ | | 1.8 | 2.0 | 1.9 | 1.9 | 2.0 | 2.0 | 2.0 | 2.0 |
| | Lignite price, €(2015)/GJ | | 0.98 | 1.07 | 1.06 | 1.04 | 1.09 | 1.12 | 1.12 | 1.12 |
| | Natural gas price, €(2015)/MWh | | 18.79 | 20.74 | 23.78 | 25.98 | 28.07 | 31.64 | 32.72 | 33.00 |
| | $CO_2$ price, €(2015)/t | | 8.60 | 15.00 | 22.50 | 33.50 | 42.00 | 50.00 | 69.00 | 88.00 |

## TABLE A4 | SENSITIVITY ANALYSIS – LOW CARBON PRICE

| | | | 2016 | 2020 | 2025 | 2030 | 2035 | 2040 | 2045 | 2050 |
|---|---|---|---|---|---|---|---|---|---|---|
| Installed capacity, MW | Coal, lignite | Existing | 4 351 | 4 112 | 4 012 | 4 012 | 1 937 | 697 | 349 | 0 |
| | | New | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Natural gas | Existing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | | New | 0 | 10 | 10 | 10 | 10 | 10 | 10 | 0 |
| | Nuclear | Existing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | | New | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | HFO/LFO | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Hydro | | 3 070 | 3 222 | 3 592 | 4 040 | 4 511 | 4 913 | 5 038 | 5 132 |
| | Wind | | 11 | 39 | 514 | 1 052 | 1 584 | 2 125 | 3 943 | 6 531 |
| | Solar | | 3 | 51 | 168 | 465 | 991 | 1 928 | 2 768 | 3 098 |
| | Other RES | | 11 | 34 | 74 | 120 | 194 | 303 | 449 | 591 |
| Gross consumption, GWh | | | 34 450 | 36 868 | 38 991 | 41 094 | 43 177 | 45 124 | 47 026 | 48 933 |
| Net electricity generation, GWh | Total | | 29 172 | 28 777 | 30 877 | 32 941 | 27 256 | 25 911 | 30 864 | 37 190 |
| | Coal and lignite | | 19 819 | 18 731 | 18 275 | 17 205 | 7 914 | 2 600 | 1 040 | 0 |
| | Natural gas | | 7 | 23 | 50 | 13 | 12 | 20 | 17 | 0 |
| | Nuclear | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | HFO/LFO | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Hydro | | 9 236 | 9 751 | 10 913 | 12 366 | 13 905 | 15 188 | 16 066 | 16 751 |
| | Wind | | 26 | 90 | 1 172 | 2 398 | 3 613 | 4 846 | 8 977 | 14 785 |
| | Solar | | 22 | 51 | 169 | 468 | 997 | 1 939 | 2 769 | 3 034 |
| | Other RES | | 62 | 131 | 296 | 490 | 816 | 1 318 | 1 995 | 2 620 |
| Net import, GWh | Total | | 5 278 | 8 091 | 8 114 | 8 153 | 15 921 | 19 213 | 16 162 | 11 744 |
| | BA_SRP | | 1 271 | 136 | 1 221 | 1 088 | 2 104 | 4 236 | 2 964 | 3 238 |
| | BG | | 2 538 | 2 585 | 1 400 | 1 297 | 3 113 | -946 | -252 | -1 007 |
| | HR | | 740 | 2 572 | 993 | 3 321 | 4 464 | 7 028 | 4 394 | 2 026 |
| | HU | | 765 | 4 037 | 1 344 | 1 336 | 1 843 | 2 278 | 140 | -1 163 |
| | MK | | -1 319 | -1 309 | -818 | -821 | -645 | -603 | 94 | 233 |
| | ME | | 119 | -2 111 | 246 | 22 | 637 | 3 124 | 2 552 | 3 349 |
| | RO | | 1 056 | 3 334 | 5 353 | 5 267 | 5 157 | 3 125 | 703 | -1 214 |
| | KO | | 109 | -1 154 | -1 626 | -3 358 | -752 | 972 | 5 568 | 6 282 |
| Net import ratio, % | | | 15.3% | 21.9% | 20.8% | 19.8% | 36.9% | 42.6% | 34.4% | 24.0% |
| RES-E share (RES-E production/gross consumption, %) | | | 27.1% | 27.2% | 32.2% | 38.3% | 44.8% | 51.6% | 63.4% | 76.0% |
| Utilisation rates of RES-E technical potential, % | Hydro | | na | na | na | na | na | na | na | 75.1% |
| | Wind | | na | na | na | na | na | na | na | 89.5% |
| | Solar | | na | na | na | na | na | na | na | 47.0% |
| Utilisation rates of conventional power production, % | Coal and lignite | | 52.0% | 52.0% | 52.0% | 49.0% | 46.6% | 42.6% | 34.1% | na |
| | Natural gas | | na | 27.0% | 57.5% | 15.5% | 14.3% | 22.8% | 19.1% | na |
| | Nuclear | | na | na | na | na | na | na | na | na |
| Natural gas consumption of power generation, TWh | | | 0 | 0 | 0.1 | 0 | 0 | 0 | 0 | 0 |
| Security of supply | Generation adequacy margin | | -2% | -8% | -7% | -4% | -29% | -39% | -39% | -39% |
| | System adequacy margin | | 82% | 71% | 84% | 85% | 98% | 86% | 97% | 90% |
| $CO_2$ emission | Emission, Mt $CO_2$ | | 23.9 | 22.5 | 21.9 | 20.6 | 9.2 | 3.0 | 1.2 | 0 |
| | $CO_2$ emission reduction compared to 1990, % | | 26.9% | 31.2% | 33.0% | 37.0% | 71.9% | 90.9% | 96.4% | 100.0% |
| Spreads | Clean dark spread, €(2015)/MWh | | 22.5 | 28.4 | 36.4 | 3.3 | -1.4 | 7.8 | -15.3 | -54.2 |
| | Clean spark spread, €(2015)/MWh | | -5.8 | -3.0 | -1.1 | -16.7 | -19.5 | -11.8 | -24.5 | -51.5 |
| Price impacts | Electricity wholesale price, €(2015)/MWh | | 31.8 | 38.5 | 46.5 | 48.7 | 53.5 | 71.6 | 68.6 | 49.9 |
| | Total RES-E support/gross consumption, €(2015)/MWh, five year average | | na | 1.1 | 5.0 | 5.7 | 7.9 | 9.2 | 11.2 | 23.7 |
| | Revenue from $CO_2$ auction/gross consumption, €(2015)/MWh | | 0 | 0 | 0 | 16.8 | 8.9 | 3.3 | 1.7 | 0 |
| Investment cost, m€/5 year period | Coal and lignite | | na | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Natural gas | | na | 9 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Total Fossil | | na | 9 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Total RES-E | | na | 295 | 1 142 | 1 488 | 1 764 | 2 033 | 3 731 | 4 115 |
| | Total | | na | 304 | 1 142 | 1 488 | 1 764 | 2 033 | 3 731 | 4 115 |
| Main assumptions | Coal price, €(2015)/GJ | | 1.78 | 1.95 | 1.93 | 1.89 | 1.98 | 2.04 | 2.04 | 2.04 |
| | Lignite price, €(2015)/GJ | | 0.98 | 1.07 | 1.06 | 1.04 | 1.09 | 1.12 | 1.12 | 1.12 |
| | Natural gas price, €(2015)/MWh | | 18.79 | 20.74 | 23.78 | 25.98 | 28.07 | 31.64 | 32.72 | 33.00 |
| | $CO_2$ price, €(2015)/t | | 4.30 | 7.50 | 11.25 | 16.75 | 21.00 | 25.00 | 34.50 | 44.00 |

## TABLE A5 | SENSITIVITY ANALYSIS – LOW DEMAND

| | | | 2016 | 2020 | 2025 | 2030 | 2035 | 2040 | 2045 | 2050 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Installed capacity, MW** | Coal, lignite | Existing | 4 351 | 4 112 | 4 012 | 4 012 | 1 937 | 697 | 349 | 0 |
| | | New | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Natural gas | Existing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | | New | 0 | 10 | 10 | 10 | 10 | 10 | 10 | 0 |
| | Nuclear | Existing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | | New | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | HFO/LFO | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Hydro | | 3 070 | 3 247 | 3 619 | 4 066 | 4 534 | 4 935 | 5 064 | 5 157 |
| | Wind | | 11 | 48 | 456 | 470 | 486 | 581 | 1 869 | 2 115 |
| | Solar | | 3 | 51 | 146 | 227 | 564 | 1 278 | 2 372 | 2 960 |
| | Other RES | | 11 | 34 | 70 | 78 | 91 | 145 | 228 | 345 |
| **Gross consumption, GWh** | | | 34 422 | 36 471 | 38 066 | 39 564 | 40 992 | 42 475 | 43 706 | 44 757 |
| **Net electricity generation, GWh** | Total | | 29 188 | 28 919 | 30 828 | 27 717 | 20 870 | 20 542 | 24 149 | 26 174 |
| | Coal and lignite | | 19 819 | 18 731 | 18 275 | 13 627 | 4 831 | 2 056 | 383 | 0 |
| | Natural gas | | 17 | 54 | 77 | 19 | 15 | 35 | 21 | 0 |
| | Nuclear | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | HFO/LFO | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Hydro | | 9 236 | 9 842 | 11 013 | 12 463 | 13 990 | 15 271 | 16 190 | 16 973 |
| | Wind | | 31 | 109 | 1 039 | 1 072 | 1 108 | 1 325 | 4 263 | 4 824 |
| | Solar | | 22 | 51 | 147 | 228 | 568 | 1 286 | 2 386 | 2 977 |
| | Other RES | | 62 | 131 | 277 | 308 | 357 | 570 | 906 | 1 400 |
| **Net import, GWh** | Total | | 5 234 | 7 553 | 7 238 | 11 847 | 20 122 | 21 932 | 19 557 | 18 583 |
| | BA_SRP | | 1 212 | 551 | 39 | 946 | 2 842 | 5 320 | 2 304 | 2 945 |
| | BG | | 2 209 | 2 622 | 1 750 | 895 | 2 643 | -217 | 566 | -1 407 |
| | HR | | 1 137 | 2 243 | 1 200 | 5 700 | 5 908 | 7 467 | 5 346 | 4 360 |
| | HU | | 920 | 3 194 | 1 772 | 3 411 | 3 446 | 3 966 | 1 377 | 554 |
| | MK | | -1 498 | -1 192 | -563 | -851 | -747 | -670 | 192 | 244 |
| | ME | | 364 | -2 015 | -2 208 | -1 565 | 3 161 | 4 463 | 5 269 | 7 431 |
| | RO | | 1 069 | 2 524 | 6 142 | 7 622 | 6 264 | 4 392 | 2 628 | -1 107 |
| | KO | | -180 | -373 | -893 | -4 310 | -3 395 | -2 789 | 1 876 | 5 565 |
| **Net import ratio, %** | | | 15.2% | 20.7% | 19.0% | 29.9% | 49.1% | 51.6% | 44.7% | 41.5% |
| **RES-E share (RES-E production/gross consumption, %)** | | | 27.2% | 27.8% | 32.8% | 35.6% | 39.1% | 43.4% | 54.3% | 58.5% |
| **Utilisation rates of RES-E technical potential, %** | Hydro | | na | na | na | na | na | na | na | 75.5% |
| | Wind | | na | na | na | na | na | na | na | 29.0% |
| | Solar | | na | na | na | na | na | na | na | 44.9% |
| **Utilisation rates of conventional power production, %** | Coal and lignite | | 52.0% | 52.0% | 52.0% | 38.8% | 28.5% | 33.7% | 12.5% | na |
| | Natural gas | | na | 62.4% | 89.1% | 21.5% | 17.5% | 39.9% | 24.5% | na |
| | Nuclear | | na | na | na | na | na | na | na | na |
| **Natural gas consumption of power generation, TWh** | | | 0 | 0.1 | 0.1 | 0 | 0 | 0.1 | 0 | 0 |
| **Security of supply** | Generation adequacy margin | | -2% | -7% | -6% | -4% | -29% | -41% | -39% | -40% |
| | System adequacy margin | | 82% | 73% | 85% | 83% | 93% | 71% | 74% | 60% |
| **$CO_2$ emission** | Emission, Mt $CO_2$ | | 23.9 | 22.5 | 21.9 | 16.1 | 5.6 | 2.3 | 0.4 | 0 |
| | $CO_2$ emission reduction compared to 1990, % | | 26.9% | 31.2% | 33.0% | 50.5% | 82.9% | 92.8% | 98.7% | 100.0% |
| **Spreads** | Clean dark spread, €(2015)/MWh | | 25.4 | 31.6 | 42.3 | 14.6 | 15.3 | 25.2 | 0.2 | -28.8 |
| | Clean spark spread, €(2015)/MWh | | -2.9 | 0.3 | 4.8 | -5.4 | -2.8 | 5.6 | -9.1 | -26.0 |
| **Price impacts** | Electricity wholesale price, €(2015)/MWh | | 34.7 | 41.8 | 52.4 | 60.0 | 70.2 | 89.0 | 84.1 | 75.3 |
| | Total RES-E support/gross consumption, €(2015)/MWh, five year average | | na | 1.1 | 3.0 | 1.4 | 1.4 | 0.3 | 0 | 0 |
| | Revenue from $CO_2$ auction/gross consumption, €(2015)/MWh | | 0 | 0 | 0 | 13.7 | 5.7 | 2.8 | 0.7 | 0 |
| **Investment cost, m€/5 year period** | Coal and lignite | | na | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Natural gas | | na | 9.1 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Total Fossil | | na | 9 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Total RES-E | | na | 337 | 1 040 | 637 | 949 | 1 281 | 3 121 | 1 123 |
| | Total | | na | 346 | 1 040 | 637 | 949 | 1 281 | 3 121 | 1 123 |
| **Main assumptions** | Coal price, €(2015)/GJ | | 1.8 | 2.0 | 1.9 | 1.9 | 2.0 | 2.0 | 2.0 | 2.0 |
| | Lignite price, €(2015)/GJ | | 0.98 | 1.07 | 1.06 | 1.04 | 1.09 | 1.12 | 1.12 | 1.12 |
| | Natural gas price, €(2015)/MWh | | 18.79 | 20.74 | 23.78 | 25.98 | 28.07 | 31.64 | 32.72 | 33.00 |
| | $CO_2$ price, €(2015)/t | | 8.60 | 15.00 | 22.50 | 33.50 | 42.00 | 50.00 | 69.00 | 88.00 |

## TABLE A6 | SENSITIVITY ANALYSIS – HIGH DEMAND

| | | | 2016 | 2020 | 2025 | 2030 | 2035 | 2040 | 2045 | 2050 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Installed capacity, MW** | Coal, lignite | Existing | 4 351 | 4 112 | 4 012 | 4 012 | 1 937 | 697 | 349 | 0 |
| | | New | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Natural gas | Existing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | | New | 0 | 10 | 10 | 10 | 410 | 410 | 410 | 400 |
| | Nuclear | Existing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | | New | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | HFO/LFO | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Hydro | | 3 070 | 3 247 | 3 619 | 4 066 | 4 534 | 4 935 | 5 064 | 5 157 |
| | Wind | | 11 | 48 | 538 | 707 | 1 544 | 2 283 | 3 820 | 6 709 |
| | Solar | | 3 | 61 | 194 | 474 | 1 071 | 2 163 | 2 894 | 3 062 |
| | Other RES | | 11 | 34 | 75 | 121 | 196 | 311 | 458 | 604 |
| **Gross consumption, GWh** | | | 34 422 | 37 195 | 39 799 | 42 414 | 45 089 | 47 774 | 50 329 | 52 904 |
| **Net electricity generation, GWh** | Total | | 29 188 | 28 936 | 31 085 | 26 809 | 24 456 | 27 176 | 31 794 | 38 610 |
| | Coal and lignite | | 19 819 | 18 731 | 18 275 | 11 747 | 2 997 | 1 442 | 374 | 0 |
| | Natural gas | | 17 | 61 | 77 | 17 | 2 044 | 1 732 | 1 588 | 729 |
| | Nuclear | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | HFO/LFO | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Hydro | | 9 236 | 9 842 | 11 013 | 12 463 | 13 990 | 15 271 | 16 184 | 16 913 |
| | Wind | | 31 | 109 | 1 227 | 1 612 | 3 521 | 5 207 | 8 709 | 15 246 |
| | Solar | | 22 | 62 | 195 | 477 | 1 078 | 2 176 | 2 908 | 3 042 |
| | Other RES | | 62 | 131 | 299 | 494 | 826 | 1 347 | 2 032 | 2 679 |
| **Net import, GWh** | Total | | 5 234 | 8 259 | 8 714 | 15 605 | 20 633 | 20 598 | 18 535 | 14 294 |
| | BA_SRP | | 915 | 820 | 2 042 | 2 451 | 3 904 | 5 272 | 2 478 | 2 187 |
| | BG | | 2 221 | 2 206 | 1 797 | 1 406 | 1 672 | -2 605 | -1 627 | -1 259 |
| | HR | | 1 110 | 2 183 | 741 | 5 068 | 5 824 | 7 669 | 4 033 | 2 484 |
| | HU | | 1 304 | 3 752 | 1 085 | 3 215 | 3 176 | 3 019 | 1 465 | -642 |
| | MK | | -1 376 | -1 117 | -202 | -982 | -56 | -483 | -13 | 262 |
| | ME | | -116 | -1 957 | -634 | 1 094 | 4 449 | 2 398 | 3 040 | 3 256 |
| | RO | | 1 383 | 2 501 | 4 655 | 6 601 | 3 206 | 4 209 | 4 672 | 1 154 |
| | KO | | -206 | -129 | -768 | -3 249 | -1 542 | 1 121 | 4 487 | 6 853 |
| **Net import ratio, %** | | | 15.2% | 22.2% | 21.9% | 36.8% | 45.8% | 43.1% | 36.8% | 27.0% |
| **RES-E share (RES-E production/gross consumption, %)** | | | 27.2% | 27.3% | 32.0% | 35.5% | 43.1% | 50.2% | 59.3% | 71.6% |
| **Utilisation rates of RES-E technical potential, %** | Hydro | | na | na | na | na | na | na | na | 75.5% |
| | Wind | | na | na | na | na | na | na | na | 92.0% |
| | Solar | | na | na | na | na | na | na | na | 46.4% |
| **Utilisation rates of conventional power production, %** | Coal and lignite | | 52.0% | 52.0% | 52.0% | 33.4% | 17.7% | 23.6% | 12.3% | na |
| | Natural gas | | na | 70.3% | 88.2% | 19.5% | 56.9% | 48.2% | 44.2% | 20.8% |
| | Nuclear | | na | na | na | na | na | na | na | na |
| **Natural gas consumption of power generation, TWh** | | | 0 | 0.1 | 0.1 | 0 | 3.5 | 3.0 | 2.7 | 1.3 |
| **Security of supply** | Generation adequacy margin | | -2% | -9% | -8% | -7% | -25% | -36% | -36% | -37% |
| | System adequacy margin | | 82% | 70% | 80% | 80% | 90% | 78% | 86% | 80% |
| **$CO_2$ emission** | Emission, Mt $CO_2$ | | 23.9 | 22.5 | 21.9 | 13.9 | 4.2 | 2.2 | 1.0 | 0.3 |
| | $CO_2$ emission reduction compared to 1990, % | | 26.9% | 31.2% | 33.0% | 57.4% | 87.3% | 93.2% | 97.0% | 99.2% |
| **Spreads** | Clean dark spread, €(2015)/MWh | | 25.4 | 32.3 | 42.6 | 49.6 | 56.2 | 69.3 | 71.6 | 61.5 |
| | Clean spark spread, €(2015)/MWh | | -2.9 | 1.0 | 5.1 | 7.5 | 10.4 | 16.7 | 16.9 | 6.2 |
| **Price impacts** | Electricity wholesale price, €(2015)/MWh | | 34.7 | 42.4 | 52.7 | 59.5 | 66.5 | 80.0 | 82.3 | 72.2 |
| | Total RES-E support/gross consumption, €(2015)/MWh, five year average | | na | 1.1 | 4.9 | 4.2 | 5.3 | 5.4 | 5.3 | 13.8 |
| | Revenue from $CO_2$ auction/gross consumption, €(2015)/MWh | | 0 | 0 | 0 | 11.0 | 3.9 | 2.3 | 1.3 | 0.4 |
| **Investment cost, m€/5 year period** | Coal and lignite | | na | 9.1 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Natural gas | | na | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Total Fossil | | na | 9 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Total RES-E | | na | 347 | 1 179 | 1 019 | 2 201 | 2 391 | 3 356 | 4 007 |
| | Total | | na | 357 | 1 179 | 1 019 | 2 201 | 2 391 | 3 356 | 4 007 |
| **Main assumptions** | Coal price, €(2015)/GJ | | 1.8 | 2.0 | 1.9 | 1.9 | 2.0 | 2.0 | 2.0 | 2.0 |
| | Lignite price, €(2015)/GJ | | 0.98 | 1.07 | 1.06 | 1.04 | 1.09 | 1.12 | 1.12 | 1.12 |
| | Natural gas price, €(2015)/MWh | | 18.79 | 20.74 | 23.78 | 25.98 | 28.07 | 31.64 | 32.72 | 33.00 |
| | $CO_2$ price, €(2015)/t | | 8.60 | 15.00 | 22.50 | 33.50 | 42.00 | 50.00 | 69.00 | 88.00 |

## TABLE A7 | SENSITIVITY ANALYSIS – LOW POTENTIAL

| | | | 2016 | 2020 | 2025 | 2030 | 2035 | 2040 | 2045 | 2050 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Installed capacity, MW** | Coal, lignite | Existing | 4 351 | 4 112 | 4 012 | 4 012 | 1 937 | 697 | 349 | 0 |
| | | New | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Natural gas | Existing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | | New | 0 | 10 | 10 | 10 | 410 | 410 | 410 | 400 |
| | Nuclear | Existing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | | New | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | HFO/LFO | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Hydro | | 3 070 | 3 207 | 3 594 | 4 063 | 4 526 | 4 818 | 4 806 | 4 754 |
| | Wind | | 11 | 25 | 431 | 472 | 586 | 1 109 | 2 744 | 3 220 |
| | Solar | | 3 | 51 | 170 | 458 | 1 345 | 2 688 | 3 365 | 4 795 |
| | Other RES | | 11 | 34 | 70 | 103 | 166 | 266 | 403 | 594 |
| **Gross consumption, GWh** | | | 34 422 | 36 831 | 38 924 | 40 968 | 43 015 | 44 996 | 46 794 | 48 592 |
| **Net electricity generation, GWh** | Total | | 29 184 | 28 722 | 30 701 | 26 787 | 22 907 | 24 748 | 28 852 | 30 835 |
| | Coal and lignite | | 19 819 | 18 731 | 18 275 | 12 368 | 3 295 | 1 612 | 405 | 0 |
| | Natural gas | | 17 | 59 | 77 | 17 | 2 279 | 1 953 | 1 834 | 696 |
| | Nuclear | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | HFO/LFO | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Hydro | | 9 236 | 9 692 | 10 918 | 12 453 | 13 962 | 14 830 | 15 225 | 15 434 |
| | Wind | | 28 | 58 | 982 | 1 076 | 1 337 | 2 530 | 6 259 | 7 328 |
| | Solar | | 22 | 51 | 171 | 461 | 1 353 | 2 705 | 3 385 | 4 783 |
| | Other RES | | 62 | 131 | 277 | 413 | 680 | 1 120 | 1 745 | 2 594 |
| **Net import, GWh** | Total | | 5 238 | 8 109 | 8 224 | 14 181 | 20 108 | 20 248 | 17 941 | 17 757 |
| | BA_SRP | | 1 145 | 510 | 1 348 | 2 598 | 2 013 | 3 070 | 37 | 905 |
| | BG | | 2 266 | 1 922 | 1 997 | 1 650 | 3 134 | -363 | 1 928 | 1 062 |
| | HR | | 1 025 | 3 099 | 887 | 5 254 | 4 405 | 7 260 | 4 159 | 3 216 |
| | HU | | 1 043 | 3 577 | 2 411 | 2 986 | 3 553 | 3 163 | 2 139 | -282 |
| | MK | | -1 550 | -1 134 | 41 | -876 | -597 | -563 | -25 | -31 |
| | ME | | 339 | -1 489 | -1 851 | -849 | 2 651 | 1 051 | 1 840 | 6 574 |
| | RO | | 1 127 | 2 375 | 4 895 | 6 846 | 6 307 | 5 956 | 4 057 | 13 |
| | KO | | -157 | -751 | -1 505 | -3 428 | -1 357 | 675 | 3 806 | 6 300 |
| **Net import ratio, %** | | | 15.2% | 22.0% | 21.1% | 34.6% | 46.7% | 45.0% | 38.3% | 36.5% |
| **RES-E share (RES-E production/gross consumption, %)** | | | 27.2% | 27.0% | 31.7% | 35.2% | 40.3% | 47.1% | 56.9% | 62.0% |
| **Utilisation rates of RES-E technical potential, %** | Hydro | | na | na | na | na | na | na | na | 68.8% |
| | Wind | | na | na | na | na | na | na | na | 44.2% |
| | Solar | | na | na | na | na | na | na | na | 72.7% |
| **Utilisation rates of conventional power production, %** | Coal and lignite | | 52.0% | 52.0% | 52.0% | 35.2% | 19.4% | 26.4% | 13.3% | na |
| | Natural gas | | na | 67.7% | 88.5% | 19.1% | 63.5% | 54.4% | 51.1% | 19.9% |
| | Nuclear | | na | na | na | na | na | na | na | na |
| **Natural gas consumption of power generation, TWh** | | | 0 | 0.1 | 0.1 | 0 | 3.9 | 3.4 | 3.2 | 1.2 |
| **Security of supply** | Generation adequacy margin | | -2% | -9% | -8% | -6% | -25% | -36% | -36% | -37% |
| | System adequacy margin | | 82% | 70% | 82% | 82% | 86% | 62% | 62% | 52% |
| **$CO_2$ emission** | Emission, Mt $CO_2$ | | 23.9 | 22.5 | 21.9 | 14.6 | 4.6 | 2.5 | 1.1 | 0.2 |
| | $CO_2$ emission reduction compared to 1990, % | | 26.9% | 31.2% | 33.0% | 55.2% | 86.0% | 92.3% | 96.7% | 99.3% |
| **Spreads** | Clean dark spread, €(2015)/MWh | | 25.4 | 32.0 | 42.4 | 49.8 | 56.4 | 71.1 | 74.9 | 63.8 |
| | Clean spark spread, €(2015)/MWh | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Price impacts** | Electricity wholesale price, €(2015)/MWh | | 34.7 | 42.2 | 52.5 | 59.6 | 66.8 | 81.7 | 85.6 | 74.4 |
| | Total RES-E support/gross consumption, €(2015)/MWh, five year average | | na | 1.0 | 4.5 | 3.3 | 4.2 | 4.5 | 6.1 | 48.5 |
| | Revenue from $CO_2$ auction/gross consumption, €(2015)/MWh | | 0 | 0 | 0 | 12.0 | 4.5 | 2.8 | 1.6 | 0.4 |
| **Investment cost, m€/5 year period** | Coal and lignite | | na | 9.1 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Natural gas | | na | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Total Fossil | | na | 9 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Total RES-E | | na | 256 | 1 080 | 981 | 1 563 | 2 101 | 3 035 | 1 850 |
| | Total | | na | 265 | 1 080 | 981 | 1 563 | 2 101 | 3 035 | 1 850 |
| **Main assumptions** | Coal price, €(2015)/GJ | | 1.8 | 2.0 | 1.9 | 1.9 | 2.0 | 2.0 | 2.0 | 2.0 |
| | Lignite price, €(2015)/GJ | | 0.98 | 1.07 | 1.06 | 1.04 | 1.09 | 1.12 | 1.12 | 1.12 |
| | Natural gas price, €(2015)/MWh | | 18.79 | 20.74 | 23.78 | 25.98 | 28.07 | 31.64 | 32.72 | 33.00 |
| | $CO_2$ price, €(2015)/t | | 8.60 | 15.00 | 22.50 | 33.50 | 42.00 | 50.00 | 69.00 | 88.00 |

## TABLE A8 | BREAK DOWN OF CUMULATIVE CAPITAL EXPENDITURE BY RES TECHNOLOGY (m€)

| Capital expenditures | No target 2016-2050 | Delayed 2016-2050 | Decarbon 2016-2050 |
|---|---|---|---|
| Biogas | 134 | 173 | 786 |
| Solid biomass | 184 | 176 | 1 220 |
| Biowaste | – | – | – |
| Geothermal ele. | 25 | 101 | 333 |
| Hydro large-scale | 1 207 | 1 342 | 1 342 |
| Hydro small-scale | 1 930 | 1 980 | 1 980 |
| Central PV | 92 | 209 | 277 |
| Decentralised PV | 554 | 2 079 | 2 159 |
| CSP | – | – | – |
| Wind onshore | 3 240 | 8 693 | 4 358 |
| Wind offshore | – | – | – |
| RES-E total | 7 366 | 14 753 | 12 456 |

## TABLE A9 | DEVELOPMENT OF SUPPORT EXPENDITURES (FOR RES TOTAL) OVER TIME (5-YEAR TIME PERIODS)

| Support expenditures in M€ | 2016-2020 | 2021-2025 | 2026-2030 | 2031-2035 | 2036-2040 | 2041-2045 | 2046-2050 | Total |
|---|---|---|---|---|---|---|---|---|
| **No target** | **192** | **176** | **62** | **2** | **–** | **–** | **–** | **432** |
| Central PV | 17 | 16 | 5 | – | – | – | – | 38 |
| Decentralised PV | 23 | 21 | 7 | 0 | – | – | – | 51 |
| Wind onshore | 32 | 27 | 10 | 0 | – | – | – | 69 |
| **Delayed** | **192** | **426** | **128** | **165** | **408** | **638** | **4 451** | **6 408** |
| Central PV | 17 | 18 | 5 | 0 | 1 | 4 | 53 | 99 |
| Decentralised PV | 23 | 29 | 8 | 6 | 32 | 71 | 525 | 695 |
| Wind onshore | 32 | 120 | 23 | 27 | 79 | 220 | 2 113 | 2 614 |
| **Decarbon** | **189** | **384** | **424** | **413** | **334** | **157** | **169** | **2 070** |
| Central PV | 17 | 23 | 15 | 9 | 7 | 2 | 23 | 97 |
| Decentralised PV | 23 | 28 | 21 | 18 | 6 | 0 | 20 | 115 |
| Wind onshore | 31 | 138 | 177 | 152 | 101 | 15 | 51 | 666 |

# Annex 2 | Assumptions

## Assumed technology investment cost trajectories: RES and fossil

TABLE A10 | ASSUMED SPECIFIC COST TRAJECTORIES FOR RES TECHNOLOGIES (2016 €/kW)

| Technology | 2015 | 2020 | 2025 | 2030 | 2035 | 2040 | 2045 | 2050 |
|---|---|---|---|---|---|---|---|---|
| Biogas (low cost options: landfill and sewage gas) | 1 663 | 1 608 | 1 555 | 1 504 | 1 454 | 1 406 | 1 360 | 1 315 |
| Biogas (high cost options: agricultural digestion in small-scale CHP plants) | 5 602 | 5 378 | 5 163 | 4 956 | 4 758 | 4 568 | 4 385 | 4 210 |
| Solid biomass (low cost options: cofiring) | 619 | 597 | 574 | 553 | 533 | 513 | 494 | 476 |
| Solid biomass (medium cost options: large-scale CHP) | 2 505 | 2 410 | 2 318 | 2 230 | 2 145 | 2 064 | 1 985 | 1 910 |
| Solid biomass (high cost options: small/medium-scale CHP) | 4 067 | 3 912 | 3 764 | 3 621 | 3 483 | 3 351 | 3 223 | 3 101 |
| Biowaste | 6 840 | 6 573 | 6 317 | 6 070 | 5 833 | 5 606 | 5 387 | 5 177 |
| Geothermal electricity (average cost trend for SEERMAP region – i.e. mix of high-temperature (default technology concepts) and medium-temperature resources (novel enhanced systems)) | 2 570 | 3 273 | 2 410 | 2 963 | 3 482 | 3 269 | 3 038 | 3 167 |
| Hydro large-scale* | 1 304 | 1 333 | 1 464 | 1 396 | 1 618 | 1 667 | 1 608 | 1 765 |
| Hydro small-scale* | 1 321 | 1 338 | 1 402 | 1 763 | 1 919 | 1 956 | 1 944 | 1 994 |
| Photovoltaics* | 1 309 | 1 015 | 908 | 824 | 764 | 693 | 640 | 596 |
| Wind onshore* | 1 491 | 1 395 | 1 311 | 1 271 | 1 246 | 1 199 | 1 150 | 1 125 |
| Wind offshore* | 3 797 | 2 693 | 2 636 | 2 521 | 2 407 | 2 293 | 2 416 | 2 346 |

Source: Green-X database

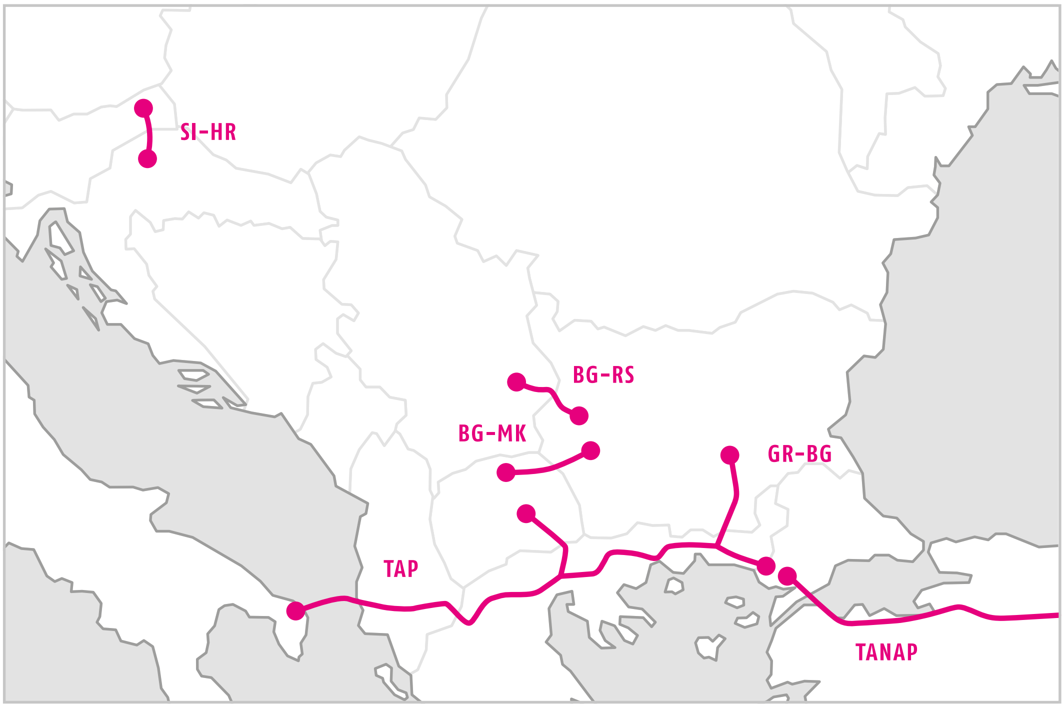
## Infrastructure (table for the whole region)

TABLE A11 | NEW GAS INFRASTRUCTURE IN THE REGION

| Pipeline | From | To | Capacity, GWh/day | Date of commissioning |
|---|---|---|---|---|
| BG-RS | BG | RS | 51 | 2018 |
| RS-BG | RS | BG | 51 | 2018 |
| TR-GR2_TAP | TR | GR | 350 | 2019 |
| GR-MK_TAP | GR | MK | 25 | 2019 |
| AZ-TR_TANAP | AZ | TR | 490 | 2018 |
| GR-BG | GR | BG | 90 | 2018 |
| GR-BG | GR | BG | 151 | 2021 |
| GR-IT_TAP | GR | IT | 334 | 2019 |
| SI-HR2 | SI | HR | 162 | 2019 |
| HR-SI | HR | SI | 162 | 2019 |
| GR-AL | GR | AL | 40 | 2019 |
| BG-MK | BG | MK | 27 | 2020 |
| HR-LNG | | HR | 108 | 2020 |
| BG-RO | BG | RO | 14 | 2016 |
| RO-BG | RO | BG | 14 | 2016 |
| GR-LNG expansion | | GR | 81 | 2017 |
| RO-HU (BRUA) | RO | HU | 126 | 2020 |
| HU-RO (BRUA) | HU | RO | 77 | 2020 |

Source: ENTSO-G TYNDP

**FIGURE A1**
NEW GAS INFRASTRUCTURE INVESTMENT ASSUMED TO TAKE PLACE IN ALL SCENARIOS




Source: ENTSO-G TYNDP 2017

**TABLE A12 | CROSS BORDER TRANSMISSION NETWORK CAPACITIES**

| From | To | Year of commissioning | Capacity, MW O → D | Capacity, MW D → O |
|---|---|---|---|---|
| ME | IT | 2019 | 500 | 500 |
| ME | IT | 2023 | 700 | 700 |
| BA_FED | HR | 2022 | 650 | 950 |
| BG | RO | 2020 | 1 000 | 1 200 |
| GR | BG | 2021 | 0 | 650 |
| RS | RO | 2023 | 500 | 950 |
| ME | RS | 2025 | 400 | 600 |
| AL | RS | 2016 | 700 | 700 |
| AL | MK | 2020 | 250 | 250 |
| RS | ME | 2025 | 500 | 500 |
| RS | BA_SRP | 2025 | 600 | 500 |
| BA_SRP | HR | 2030 | 350 | 250 |
| HR | RS | 2030 | 750 | 300 |
| HU | RO | 2035 | 200 | 800 |
| RS | RO | 2035 | 500 | 550 |
| RS | BG | 2034 | 50 | 200 |
| RS | RO | 2035 | 0 | 100 |
| RS | BG | 2034 | 400 | 1 500 |
| GR | BG | 2030 | 250 | 450 |
| KO* | MK | 2030 | 1 100 | 1 200 |
| KO* | AL | 2035 | 1 400 | 1 300 |
| MD | RO | 2030 | 500 | 500 |
| BG | GR | 2045 | 1 000 | 1 000 |
| HU | RO | 2043 | 1 000 | 1 000 |
| HU | RO | 2047 | 1 000 | 1 000 |
| IT | ME | 2045 | 2 000 | 2 000 |
| IT | GR | 2037 | 2 000 | 2 000 |
| IT | GR | 2045 | 3 000 | 3 000 |

Source: ENTSO-E TYNDP 2017

## Generation units and their inclusion in the core scenarios

**TABLE A13 | LIST OF GENERATION UNITS INCLUDED EXOGENOUSLY IN THE MODEL IN THE CORE SCENARIOS**

| Unit name | Installed capacity [MW] | Expected year of commissioning | Expected year of decommissioning | Fuel type | Type | CCS | No target | Delay | De-carbon |
|---|---|---|---|---|---|---|---|---|---|
| Kolubra A1 | 32 | 1956 | 2020 | lignite | thermal | no | yes | yes | yes |
| Kolubra A2 | 32 | 1957 | 2020 | lignite | thermal | no | yes | yes | yes |
| Kolubra A3 | 65 | 1961 | 2020 | lignite | thermal | no | yes | yes | yes |
| Kostolac A1 | 100 | 1967 | 2024 | lignite | thermal | no | yes | yes | yes |
| Morava | 120 | 1969 | 2031 | lignite | thermal | no | yes | yes | yes |
| Nikola Tesla A1 | 210 | 1970 | 2031 | lignite | thermal | no | yes | yes | yes |
| Nikola Tesla A2 | 210 | 1970 | 2031 | lignite | thermal | no | yes | yes | yes |
| Nikola Tesla A3 | 329 | 1976 | 2031 | lignite | thermal | no | yes | yes | yes |
| Nikola Tesla A4 | 308.5 | 1978 | 2033 | lignite | thermal | no | yes | yes | yes |
| Nikola Tesla A5 | 340 | 1979 | 2034 | lignite | thermal | no | yes | yes | yes |
| Nikola Tesla A6 | 347.5 | 1979 | 2034 | lignite | thermal | no | yes | yes | yes |
| Kolubra A5 | 110 | 1979 | 2019 | lignite | thermal | no | yes | yes | yes |
| Kostolac A2 | 210 | 1980 | 2035 | lignite | thermal | no | yes | yes | yes |
| Nikola Tesla B1 | 620 | 1983 | 2038 | lignite | thermal | no | yes | yes | yes |
| Nikola Tesla B2 | 620 | 1985 | 2040 | lignite | thermal | no | yes | yes | yes |
| Kostolac B1 | 348.5 | 1987 | 2042 | lignite | thermal | no | yes | yes | yes |
| Kostolac B2 | 348.5 | 1991 | 2046 | lignite | thermal | no | yes | yes | yes |
| CHP Novi sad | 9.9 | 2016 | 2046 | natural gas | CCGT | no | yes | yes | yes |
| CHP Pancevo – 478 | 478 | 2019 | 2049 | natural gas | CCGT | no | yes | yes | yes |
| Kolubara B | 700 | 2021 | 2076 | lignite | thermal | no | yes | no | no |
| Kostolac B3 | 350 | 2026 | 2081 | lignite | thermal | no | yes | no | no |
| Nikola Tesla B3 | 350 | 2026 | 2081 | lignite | thermal | no | yes | no | no |

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