SEERMAP

South East Europe Electricity Roadmap

SOUTH EAST EUROPE ELECTRICITY ROADMAP

Regional report

South East Europe

SEERMAP: South East Europe Electricity Roadmap
South East Europe Regional report 2017

Authors:
REKK: László Szabó, András Mezősi, Zsuzsanna Pató, Ágnes Kelemen (external expert), Ákos Beöthy, Enikő Kácsor and Péter Kaderják
TU Wien: Gustav Resch, Lukas Liebmann and Albert Hiesl
OG Research: Mihály Kovács and Csaba Köber
EKC: Slobodan Marković and Danka Todorović

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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*, FYR 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).

REKK FOUNDATION

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.

TU WIEN TECHNISCHE UNIVERSITÄT WIEN

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.

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ekc

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.

OGResearch

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.

ERRA ENERGY REGULATORS REGIONAL ASSOCIATION

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

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.

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.

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.

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1 | Executive summary

South East Europe is a diverse region with respect to energy policy and legislation, comprising a mix of EU member states, candidate and potential candidate countries. Despite this diversity, shared challenges and opportunities exist. The electricity network of the South East Europe region is highly connected, energy policies more harmonised and electricity markets better integrated – as a result of the EU accession process, the Energy Community Treaty and, more recently, the Energy Union initiative supporting a regional perspective on policy development. This report emphasises the regional dimension; it is complemented by national reports available on the South East Europe Energy Roadmap (SEERMAP) website (http://seermap.rekk.hu).

The SEERMAP project uses a model-based assessment of different long term electricity investment strategies for Albania, Bosnia and Herzegovina, Bulgaria, Greece, Kosovo*, former Yugoslav Republic of Macedonia, Montenegro, Romania and Serbia. It builds upon previous work in the region, namely IRENA (2017), the DiaCore, BETTER and SLED projects, but also EU-level analysis, notably the EU Reference Scenario 2013 and 2016. The current assessment shows that alternative solutions exist for replacing current generation capacity by 2050, with different implications for affordability, sustainability and security of supply.

The SEERMAP region will need to replace more than 30% of its current fossil fuel generation capacity by the end of 2030, and more than 95% by 2050. This provides both a challenge to ensure a policy framework which will incentivise new investment, and an opportunity to shape the electricity sector over the long term in-line with a broader energy transition strategy unconstrained by the current generation portfolio.

Five models incorporating the electricity and gas markets, the transmission network and macro-economic system were used to assess the impact of three core scenarios:

- The 'no target' scenario reflects the implementation of existing energy policy (including implementation of renewable energy targets for 2020 and construction of all power plants included in official planning documents) combined with a CO_2 price (which is only envisaged from 2030 onwards for non EU member states). The scenario does not include an explicit 2050 CO_2 target or a renewables target for the electricity sectors of the EU member states or countries in the Western Balkans;
- The 'decarbonisation' scenario reflects a long-term strategy to significantly reduce CO_2 emissions, in line with indicative EU emisison reduction goals for the electricity sector as a whole by 2050, driven by the CO_2 price and strong, consistent RES support;
- The 'delayed' scenario involves an initial implementation of current national investment plans (business-as-usual policies) 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. Decarbonisation 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 strategies that countries in the SEERMAP region can pursue:

- Under scenarios with an ambitious decarbonisation target in line with the EU Roadmap and corresponding RES support schemes, the SEERMAP region would have an electricity mix with 83-86% renewable generation, mostly hydro and wind, and a significant share of solar by 2050. If renewable support is phased out and no CO_2 emission target is set, but a carbon price is applied, the share of RES in electricity consumption will rise to around 58% in 2050 from current levels.

- The modelling results show that even with RES support phased out after 2025, the region's electricity sector will experience a very significant decarbonisation by 2050, with a reduction in emissions of almost 91% by 2050 compared with 1990. However, results differ by country, with decarbonisation rates reaching very high levels in some countries without support, but insufficient in other countries, such as Greece and Kosovo*, compared with decarbonisation levels targeted by the EU by 2050. This level of decarbonisation assumes nuclear power plants of a total capacity of around 4800 MW operating in Romania and Bulgaria, as well as 600 MW carbon capture and storage (CCS) capacity in Kosovo*.
- Driven by a high carbon price, a significant amount of fossil fuel based generation capacity will be replaced by 2050. Coal, lignite and oil capacities are phased out almost completely under all scenarios resulting in lower and unprofitable utilisation rates.
- Delayed action on renewables is feasible, but has two distinct disadvantages compared with a long term planned RES support. First, it results in stranded fossil based power generation assets, including currently planned power plants. Stranded assets are assets where investment cost is not recovered during the lifetime of the investment. Translated into a price increase equivalent over a 10 year period, the cost of stranded assets is on par with the size of RES support needed for decarbonisation of the electricity sector; the weighted average RES support in the region over the entire modelled period is around 3.7 EUR/MWh, compared with the 10-year price increase caused by stranded costs of 2.5 EUR/MWh. Stranded costs are particularly high in Bosnia and Herzegovina, Greece and Kosovo* in both the 'no target' and 'delayed' scenarios. Assuming delayed action, the disproportionate effort required towards the end of the modelled period to meet the CO_2 emissions target results in the need for significantly more RES support between 2040 and 2050.
- Natural gas will remain relevant over the next few decades, contingent upon the completion of the Transadriatic (TAP) and Transanatolian (TANAP) pipelines bringing alternative natural gas supply from the Shah Deniz II gas field to the region. All scenarios initially foresee an increase in natural gas use, but under a decarbonisation pathway in line with the EU target of 93-99% reduction in the electricity sector gas plays only a very minor role towards the end of the period, accounting for 1.5% of generation in 2050. In the 'decarbonisation' scenario total gas capacity declines from 2020, with the rate of newly added capacity lower than outgoing capacity. Even so, capacity is still sufficient to bridge the transition from fossil to renewable based electricity mix with higher utilisation rates peaking between 2025 and 2035. Under the 'no target' scenario, gas still provides 15% of regional electricity generation in 2050 with peak production expected around 2035.
- Throughout the modelling period in all scenarios, the SEERMAP region as a whole produces approximately the same amount of electricity as it consumes. However, significant differences emerge between countries; in particular, Serbia, Macedonia and Kosovo* are large net importers, whereas Albania will be a significant net exporter by 2050.
- The generation adequacy indicator remains favourable for the region as a whole, i.e. regional generation capacity is sufficient to satisfy regional demand in all hours of the year for all of the years shown. The system adequacy indicator for the region as a whole, which takes into account import possibilities as well as regional generation capacities, is even higher. However, the generation adequacy margin varies for individual countries, and is negative for some countries in some scenarios, in particular

for Albania, Kosovo* and Serbia. This means that during certain time periods, these countries would need to import electricity to be able to satisfy domestic demand. Electricity import is a key element of market operation, improving social welfare of trading countries by ensuring that electricity is produced where it is cheapest. It is also in line with regional and a broader EU approach which relies on cooperation and solidarity between member states.

- At the country level, negative generation adequacy is linked to the two scenarios with decarbonisation targets. Increasing the generation adequacy margin to ensure that demand can be satisfied with domestic capacities at all times would require additional investment in new capacities and higher electricity prices, which underlines the importance of regional cooperation. Concerted efforts towards market integration and increasing the capacity of interconnections can reduce generation investment costs in scenarios with high shares of renewable generation. Additional positive effects of regionalisation include smoothing of electricity generated by intermittent RES capacities.
- 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 when high levels of low marginal cost RES penetration in the electricity mix reduce wholesale prices.
- The wholesale electricity price deviates slightly among countries, but follows a very similar trajectory across the region. This is attributable to the high level of interconnectedness within the region and the gradual coupling of markets. There is a significant increase in the average wholesale electricity price in the region (and across Europe) compared with current historically low levels under all scenarios due to the significant rise in carbon and natural gas prices by 2050.
- The macroeconomic analysis shows that despite the high absolute increase in the wholesale price, household electricity expenditure relative to income is expected to increase only slightly, due to significant growth in household disposable income. The positive implication of this trend is that higher prices attract investment to new electricity generation, which would help close the current gap in necessary funding for electricity generation projects.
- Decarbonisation will require a very significant increase of investment in generation capacity. These investments are assumed to be financed by private actors who accept higher CAPEX in exchange for low OPEX (and RES support) in their investment decisions. From a socio-economic perspective, the high level of investment in the decarbonisation of the power sector has a positive impact on GDP and employment. In 5 out of 9 countries, the positive impact on GDP is the biggest in the 'decarbonisation' scenario, while in the rest of the countries, the 'delayed' scenario is associated with the biggest economic growth. The 'decarbonisation' scenario has the strongest employment effect in 5 out of 9 countries due to the fact that renewable deployment (most notably PV) has much higher employment intensity than traditional fossil fuel plants. At the same time the higher level of renewable generation in these scenarios decrease the long term regional external debt by 8% of GDP on average as a result of an improving current account due to lower electricity and gas imports compared to the baseline.
- Decarbonisation will require continued RES support during the entire period. However, the need for support decreases as the electricity wholesale price increases and thereby incentivises significant RES investment even without support.
- At the regional level, revenues from the auction of EU ETS allowances are more than sufficient to cover the necessary RES support with the exception of the last 5 or 10 years of the

modelled period in the 'decarbonisation' and 'delayed' scenarios. The national results are more varied; in some countries the revenues can only partially cover the necessary support.
- The sensitivity analysis reveals that regional RES targets are significantly more cost-effective than national targets, to the point that the required RES support in a national target scenario is twice the level of the support needed in a regional support scenario assuming the same decarbonisation target. A regional system will also encourage harmonisation of other support elements such as permitting, grid connection rules, financing, taxation, etc.
- According to the network modelling, overall transmission network investment needs in the region are not significant compared to generation investments. Our estimates, however, do not include distribution network investments, where in some countries are characterised by significant underinvestment in the region and further investment will be required in order to accommodate a high share of renewables in the electricity system.

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 that policy should focus on enabling RES integration; this involves investing in transmission and distribution networks, enabling demand side management and RES generation through a combination of technical solutions and appropriate regulatory incentives. Policy-makers should also promote investment in storage solutions, including hydro and small scale storage. In addition, increasing the capacity of interconnections, completing regional market integration and creating the framework conditions for investment in large scale storage solutions require higher levels of regional cooperation.
- RES potential can be reaped through policies that eliminate barriers to RES investment. De-risking policies addressing high financing cost and addressing high cost of capital are especially relevant in the entire region where currently weighted average cost of capital values are high in all countries. De-risking would allow for cost-efficient renewable energy investments. Options for implementing regional level de-risking facilities may be considered. An active role of the EU in implementing such a de-risking facility could provide a significant impetus. Policy related risks can also be reduced by ensuring stable, long term renewable energy policy frameworks are in place.
- As revenues from the auctioning of EU ETS allowances are sufficient to cover RES support for most of the modelled period, a scheme to finance RES support from these revenues can be devised in order to relieve the burden on consumers.
- Co-benefits of investing in renewable electricity generation can strengthen the case for increased RES investment. Co-benefits include higher GDP as a result of increased investment in generation capacity, an improved external balance due to reduced electricity and gas imports, and lower wholesale energy price which can result from very high penetration of RES. Additional co-benefits, not assessed here, are health and environmental benefits from reduced emissions of air pollutants.
- Policy makers need to address the trade-offs which characterise fossil fuel investments. In particular stranded costs related to coal, lignite and natural gas generation assets need to be weighed against any short term benefits that such investments may provide, such as in the case of natural gas, which can temporarily bridge the transition from coal to renewables.
- Considering the transient role that natural gas plays in the two scenarios with a decarbonisation target, the costs related to investments in natural gas networks also need to be

weighed against the benefits of natural gas based electricity generation (also considering other uses of natural gas in sectors such as industry and buildings).

- Regional cooperation can significantly lower support costs and results in slightly lower investment needs for meeting RES targets. A regional target for renewables is therefore recommended, but in order to reach a win-win situation for all involved countries, corresponding regional support mechanisms could also be explored. In parallel to implementing a regional support mechanism, issues such as differences in permitting, grid connection rules, financing, taxation, site restrictions, depreciation rules, etc. should be eliminated in order to avoid market distortions. The EU is already moving to strengthen regional RES cooperation, most recently with the 2016 Winter Package which proposes partial opening of support schemes, already being tested in some countries. Best practices established in this process will help the SEE region and improve regional cooperation in RES support schemes to ultimately increase their economic efficiency.
- Policy-makers need to address the gap in distribution network investment, which is crucial to the expansion of the decentralised RES-based power production. Transmission network development in the SEE region also needs to be accelerated, and current instruments (e.g. PECI selection process) need to be strengthened and backed by financial instruments to move selected projects from pre-feasibility to commissioning.
- In order to achieve a large-scale energy transition in the region, there is a need to increase administrative capacity, improve governance practices in the sector and ensure participation and engagement of stakeholders in decision making. While the electricity sector modelling results show least cost investment pathways, the model operates in an ideal world; imperfect implementation of energy policies can significantly increase costs in the real world compared with modelled results. In order to ensure that the modelled minimum cost energy system can be translated into reality, it is necessary to base renewable energy policies on sound analysis, take into account the interests of consumers and avoid institutional capture. This is particularly important as the vulnerability of consumers in the region is high, and ineffective implementation of RES policies may result in significant price increases, producing a backlash against renewable energy.

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 the 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 the region: 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

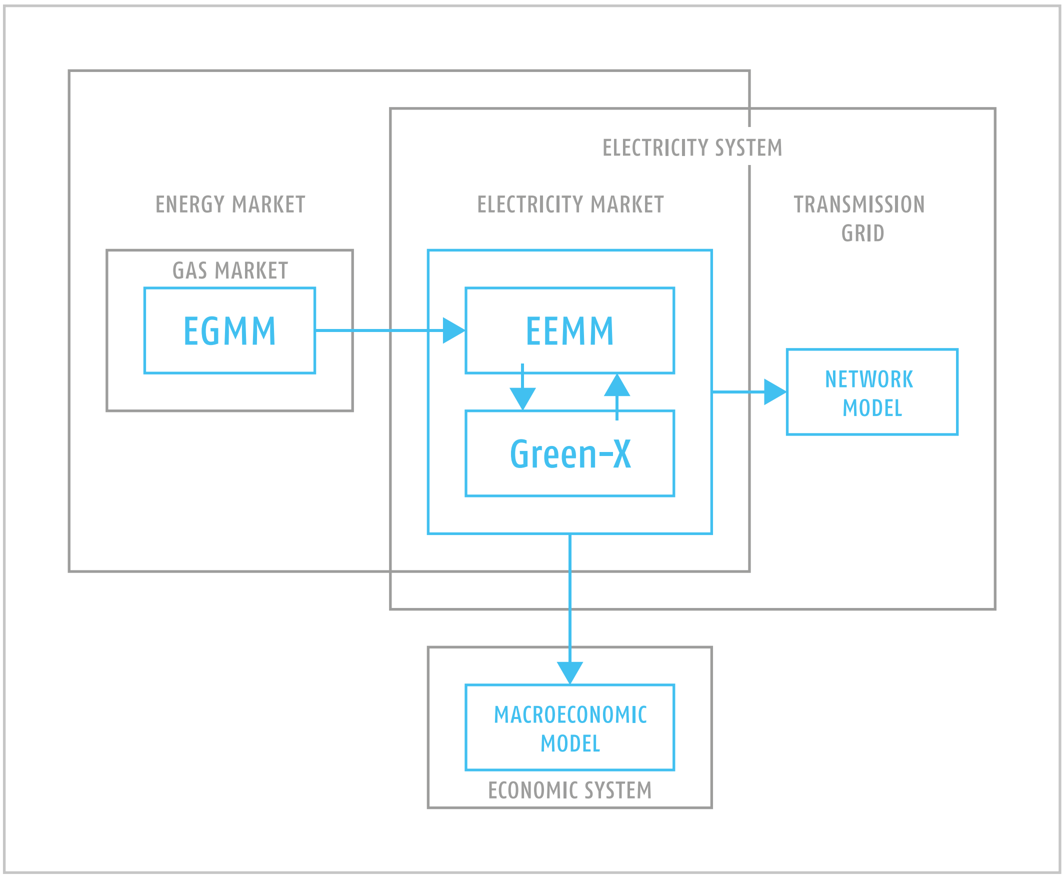
This report summarises the contribution of the SEERMAP project to the ongoing policy debate on how to enhance the decarbonisation of the electricity sector in South East Europe. We inform on the work undertaken, present key results gained and offer a summary of key findings and recommendations on the way forward.

Geographically we focus in this report on the whole South East Europe region, including the EU member states Bulgaria, Greece and Romania as well as the candidate and potential candidate countries Albania, Bosnia and Herzegovina, Kosovo*, Macedonia, Montenegro and Serbia. Please note that further information on the analysis conducted at country level can be found in the individual SEERMAP country reports.

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 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, whereby 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.

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")



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 allows for the incorporation of the impacts of EU market developments on the focus 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 are 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.

The 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 3 core scenarios:

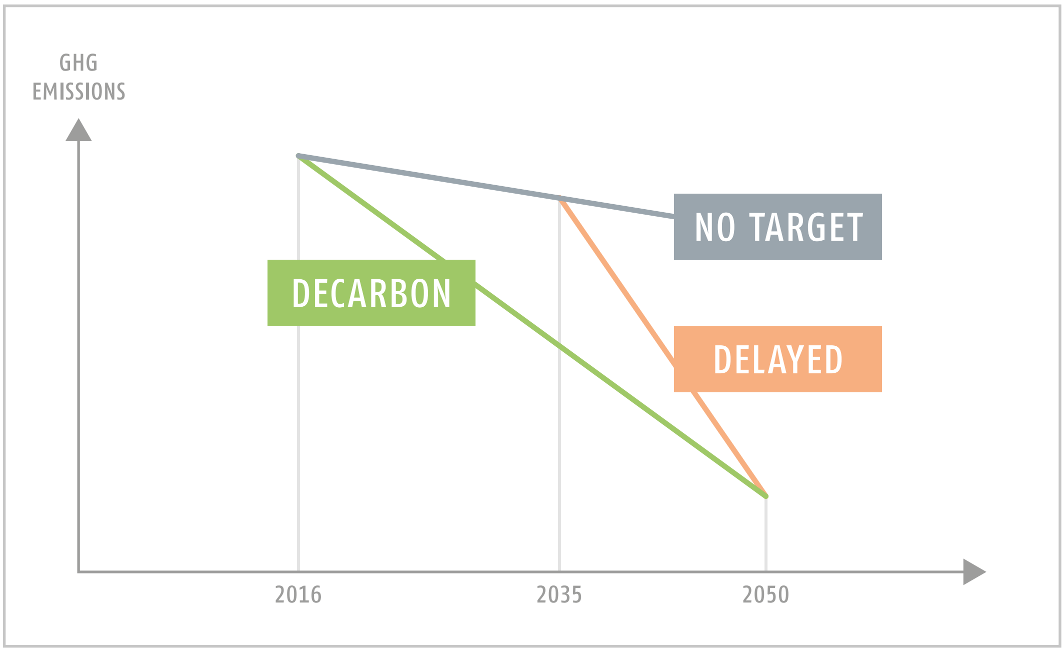
- The 'no target' scenario reflects the implementation of current energy policy and no CO_2 target in the EU and Western Balkans for 2050;
- The 'decarbonisation' scenario reflects a continuous effort to reach significant reductions of CO_2 emissions, in line with long term indicative EU emission reduction 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.

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 reduction 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

FIGURE 2
THE CORE SCENARIOS



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.
- 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 both oil and coal is expected to increase by approximately 15% by 2050 compared with 2016. The gas price is differentiated by country, the increase in the price of gas is between 66 and 93% in the different countries in the SEERMAP region.
- 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. Other studies also estimated WACC values for the region and confirm that values are high. Ecofys – Eclareon (2017) estimated current WACC values for onshore wind to be between 7-13.7% and for PV between 7-12.4% for the EU3 countries. IRENA (2017) assumed medium level WACC values of 8 to 10% for SEE countries in 2016.
- Carbon price: a price for carbon is applied for the entire modelling period for EU member states and from 2030 onwards for 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/tCO_2 in

2030 to 88 EUR/tCO_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 TAP and 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.

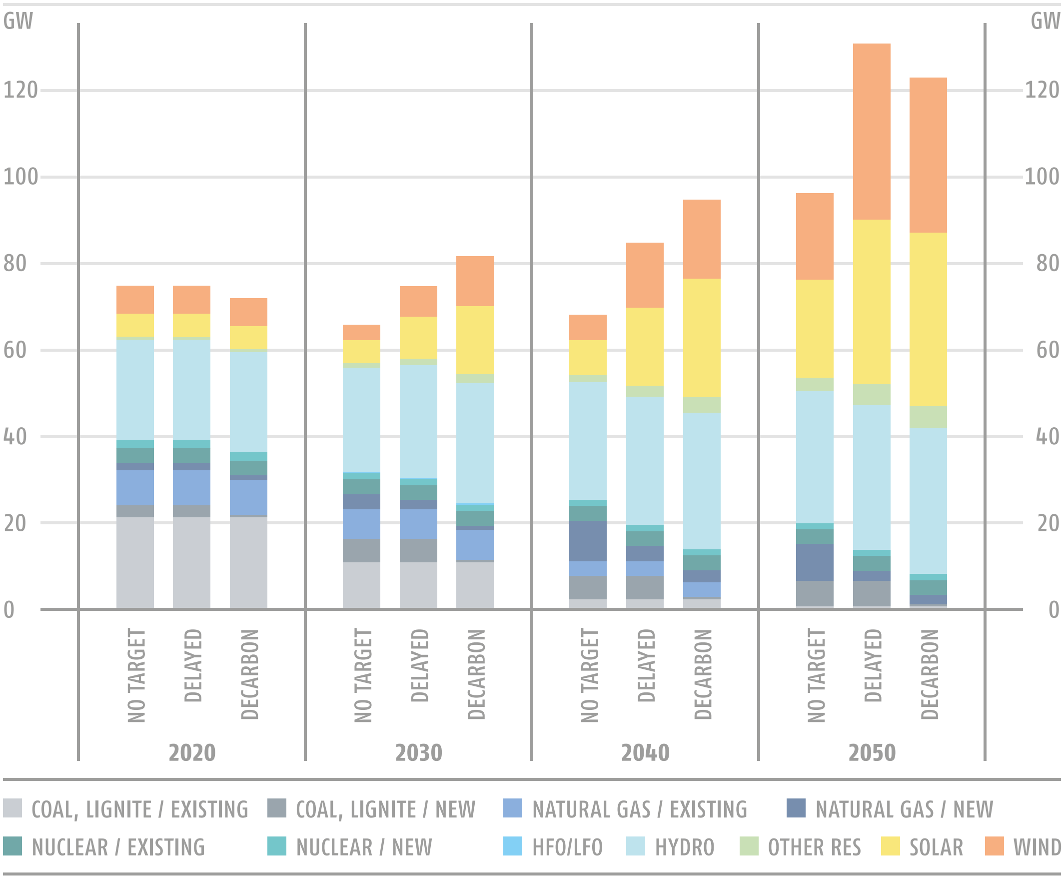
5 | Results

5.1 Main electricity system trends

The main investment challenge in the SEERMAP region is replacing currently installed lignite and oil based capacities, of which more than 30% is expected to be decommissioned by the end of 2030 and more than 95% by 2050.

The model results show that the least cost capacity options under the assumed costs and prices are renewables (in particular wind, hydro and solar) in emission reduction target scenarios and a mix of natural gas and renewables in the 'no target' scenario.

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



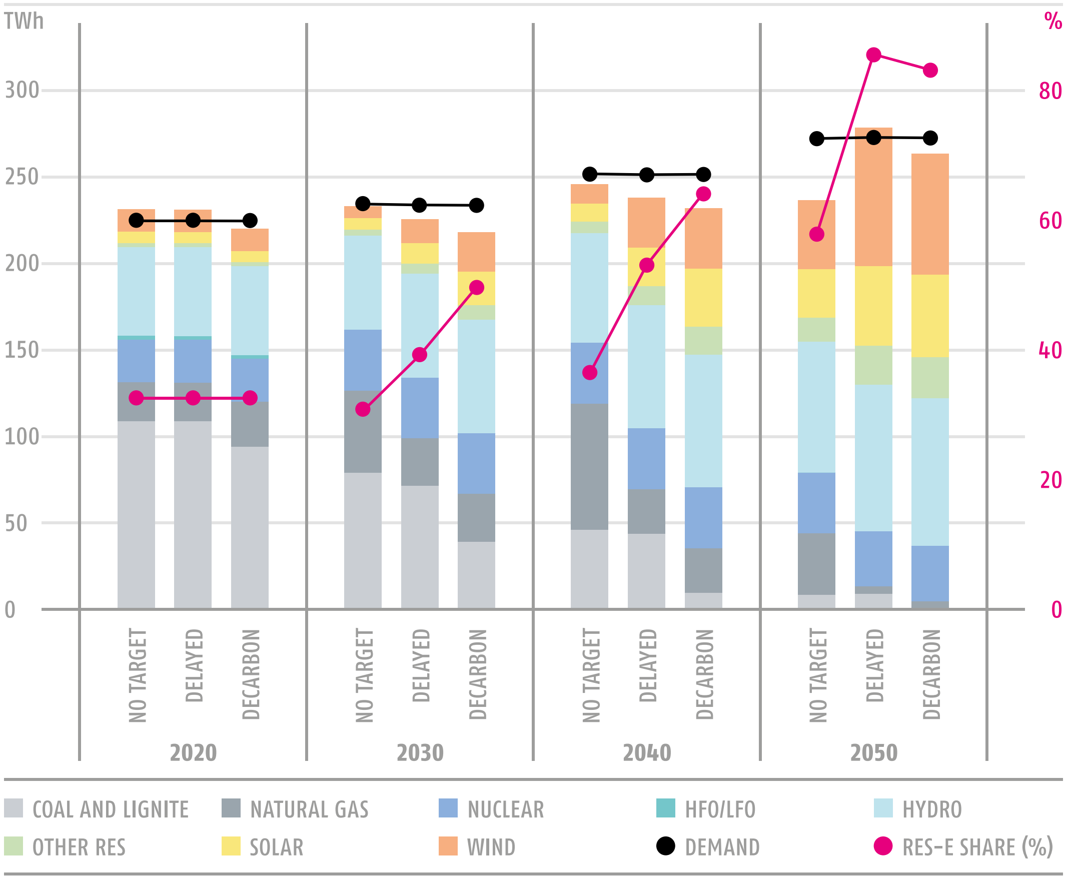
The capacity mix changes significantly in all three core scenarios, with a shift away from fossil based towards renewable capacity. The changes in the capacity mix are driven primarily by increasing carbon prices and decreasing renewable technology costs. Oil capacity disappears after 2035 in all scenarios, while coal and lignite based capacity drops from an initial 24.2 GW in 2016 to 6.6 GW by 2050 in the 'no target' and 'delayed' scenarios, and to 1.2 GW in the 'decarbonisation' scenario. By 2050, most of the coal capacity can be found in Bosnia and Herzegovina, Kosovo* and Serbia in both the 'no target' and 'delayed' scenarios according to model results, with 2000, 1100 and 1400 MW capacity respectively. In the 'decarbonisation' scenario the entire coal capacity in the SEERMAP region is based in 3 countries: Bosnia and Herzegovina, Bulgaria and Greece.

Nuclear capacity investment decisions have not been modelled, but were entered into the model exogenously; apart from the two existing plants in Bulgaria and Romania in Kozloduy and Cernavoda a new 1400 MW capacity nuclear plant is expected to begin operation in Romania by 2028 accorind to national plans.

Carbon capture and storage capacity does not enter into the model as the cost of CCS is higher than that of renewables. One 600 MW CCS lignite plant was included exogenously in the model in Kosovo* in the 'no target' and 'delayed' scenarios based on consultation with national stakeholders; the plant was assumed to come online in 2041.

Renewable capacity becomes increasingly important in all three scenarios. Investment in new wind capacities is significant, tripling in the 'no target' scenario from 6 GW in 2016 to around 20 GW in 2050. In the two scenarios with a decarbonisation target for 2050 the growth is even more significant, with wind capacity reaching 41 GW and 36 GW in the 2050 'delayed' and 'decarbonisation' scenarios respectively. Relative wind capacity

FIGURE 4
ELECTRICITY GENERATION AND DEMAND (TWh) AND RES SHARE (% OF DEMAND) IN THE SEERMAP REGION, 2020-2050



increase is especially high in the WB6 countries, where most countries have no or limited experience in operating wind farms.

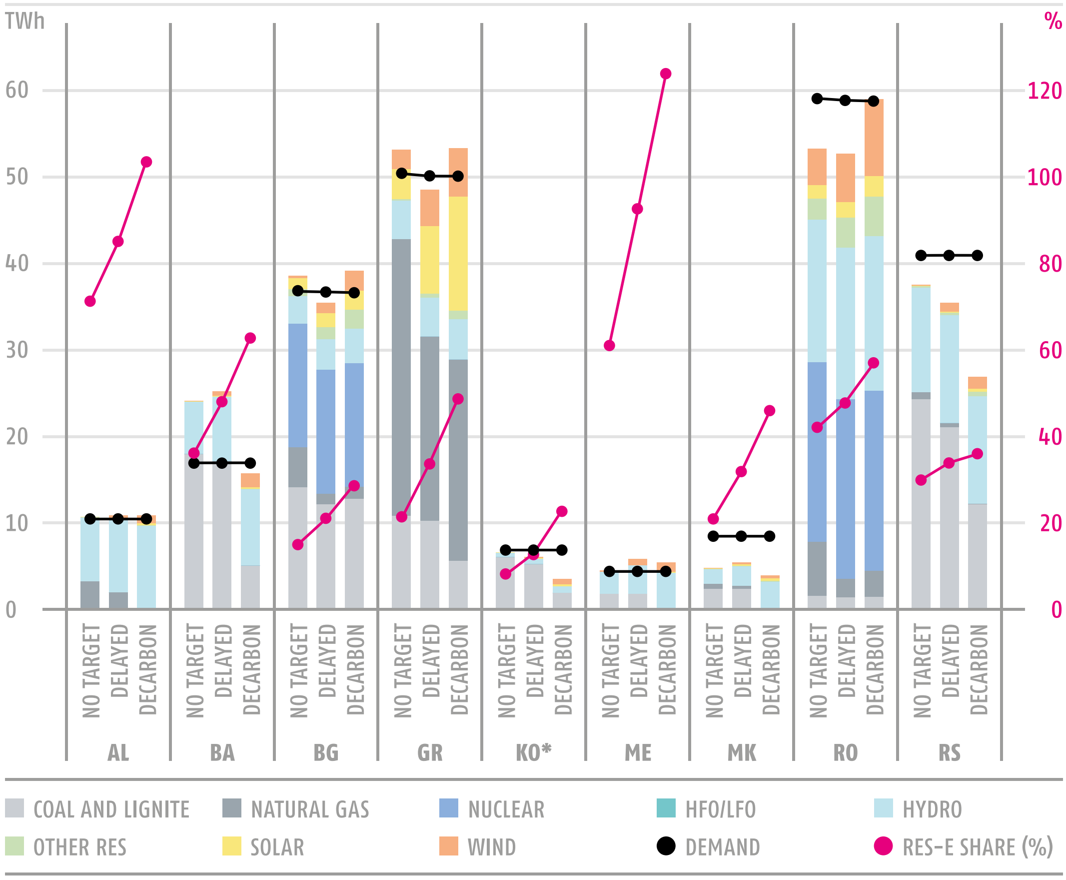
Solar capacity is comparable to wind capacity in the region by the end of the modelling period in all scenarios, moving from 5 GW in 2016 to some 23 GW in the 'no target', 38 GW in the 'delayed' and 40 GW in the 'decarbonisation' scenario by 2050. Although photovoltaic generation remains more expensive than wind generation throughout the modelled period, investment in small scale photovoltaic installations is boosted by its ability to compete in retail electricity markets whereas wind and large scale PV farms compete against the wholesale electricity price.

The relative increase in hydro capacity is the lowest of the three main RES technologies due to sustainability concerns and competing water uses. It increases by 40% in the 'no target' scenario and 54-55% in the other two other scenarios between 2016 and 2050. There is an especially low relative increase from current levels in hydro capacity in the EU3 in all scenarios, while growth rates are generally higher in the WB6.

Biomass makes up most of the 'other RES' category, with a share in total capacity of 3-4% in all scenarios by 2050, which represents approximately a 10-fold increase on 2016 levels in the 'no target' scenario, and almost 20-fold increase in the other two scenarios.

Natural gas investment shows very different patterns across the three core scenarios. Gas capacity increases by more than 40% by 2040 compared with 2016 in the 'no target' scenario, but then decreases to near current levels by 2050. In the 'delayed' scenario there is a 12% increase in gas capacity by 2025, followed by a reduction in capacity until 2050 settling near one quarter of current capacity. The 'decarbonisation' scenario entails even lower levels of initial growth in gas capacity, and gas based generation capacity

FIGURE 5
ELECTRICITY GENERATION AND DEMAND (TWh) AND RES SHARE (% OF DEMAND) BY COUNTRY, 2030

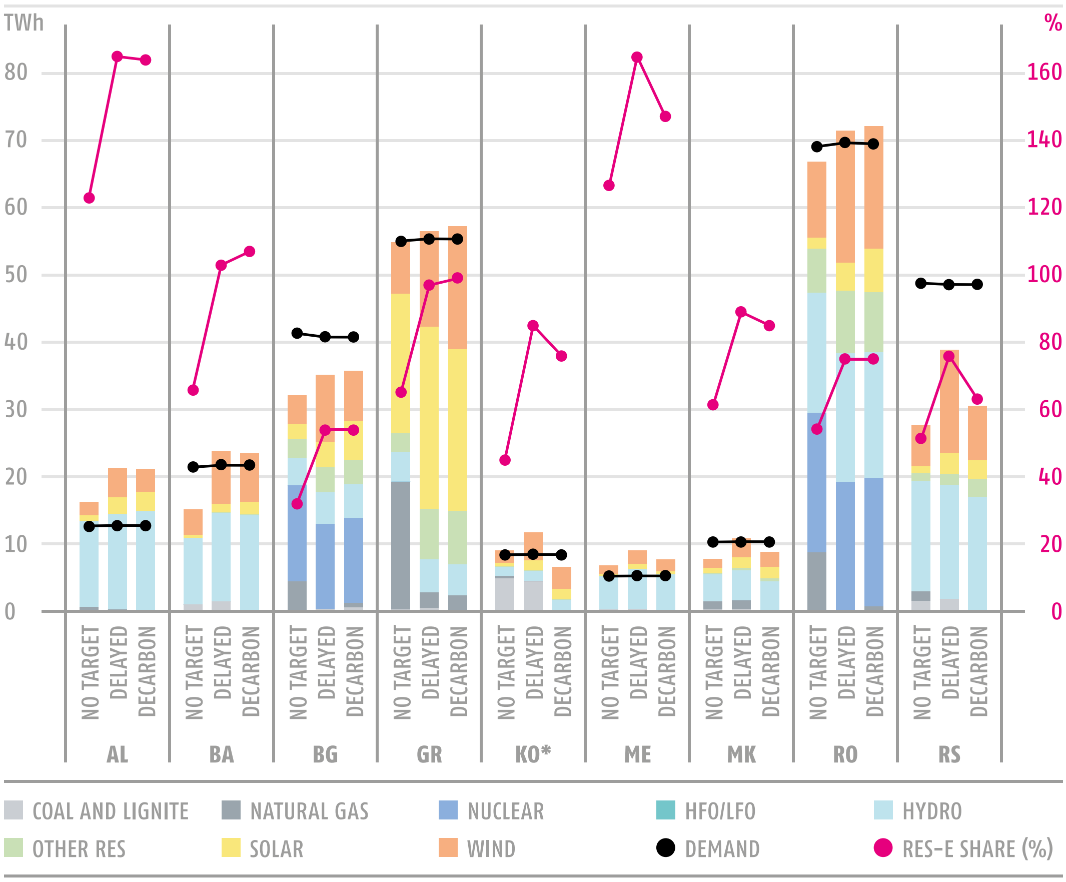


peaks earlier, in 2020. In all scenarios, the bulk of natural gas capacity is located in the EU3 countries due to domestic gas production (especially in Romania) and their proximity to the TAP or TANAP pipelines (for Greece and Bulgaria) resulting in low transport costs.

The generation mix follows a similar pattern to the capacity mix. In all scenarios there is a significant increase in the share of renewables by 2050, with hydro, wind and solar making significant contributions. Hydro remains the renewable energy source with the highest contribution to generation in all three scenarios. Solar and wind have the highest relative growth by 2050 compared to 2016, with significantly lower growth in hydro. Wind has a relative advantage compared with solar in all countries in the region with the exception of Greece.

Natural gas plays a transitory role in electricity generation in all scenarios, with gas based generation peaking in 2040 in the 'no target' scenario, in 2025 in the 'delayed' scenario, and between 2025 and 2035 in the 'decarbonisation' scenario. The initial increase in gas based generation is driven by an increase in the carbon price, which prices out coal and lignite based generation before sufficient renewable capacity is installed. Later on gas based generation decreases as the carbon price increases further and renewable technologies become cheaper. While at its peak gas based generation is four times the current value in the 'no target' scenario, responsible for almost 30% of total generation, it is only twice the current value in the 'delayed' and 'decarbonisation' scenarios. The divergent outcomes between the scenarios are due to different RES support patterns, which in some scenarios enable renewable based generation to compete successfully against natural gas earlier than in others. The temporary

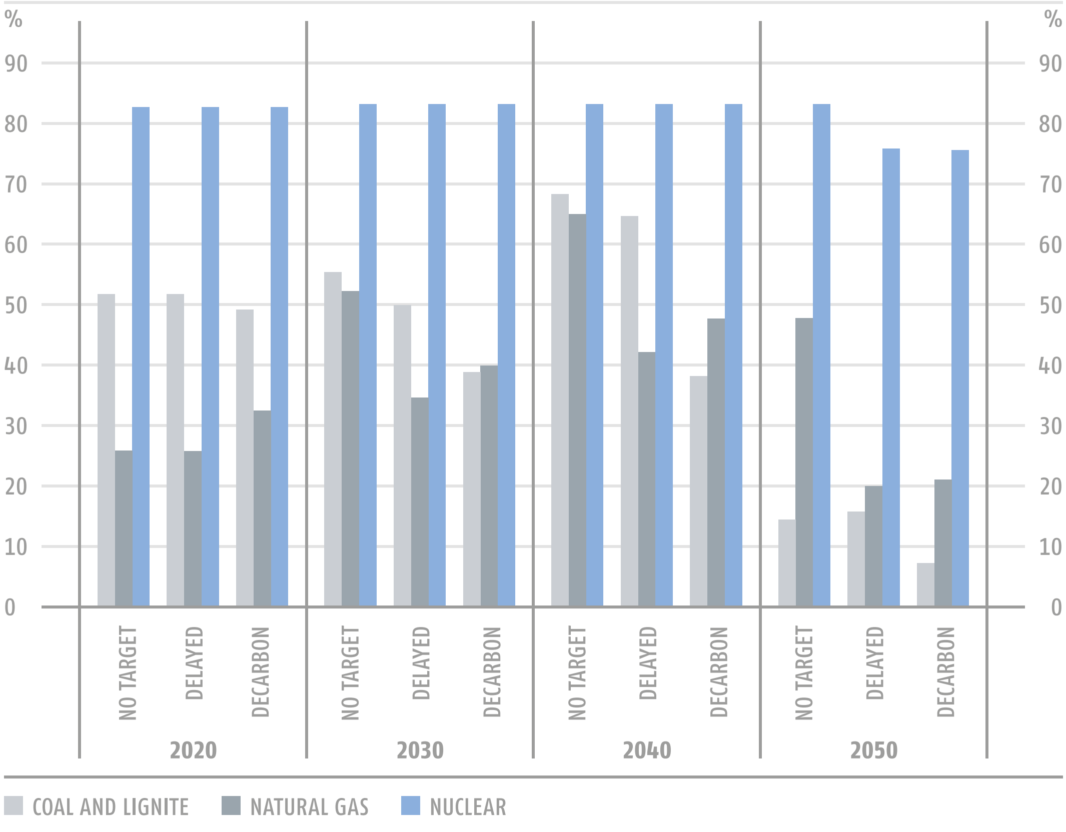
FIGURE 6
ELECTRICITY GENERATION AND DEMAND (TWh) AND RES SHARE (% OF DEMAND) BY COUNTRY, 2050



increase in natural gas based generation is assisted in all scenarios by higher utilisation rates of existing gas based generation capacities. In both the 'delayed' and 'decarbonisation' scenarios most of the generation increase is due to higher utilisation rates, with increased capacity playing a role in the 'delayed' but not in the 'decarbonisation' scenario. In all scenarios most gas based electricity is produced in the EU3, especially in Greece during the middle of the modelled time horizon when RES is not sufficiently cheap but coal and lignite based generation is already decreasing. Two WB6 countries, Bosnia and Herzegovina and Montenegro, have no gas based electricity generation in any of the scenarios.

The SEERMAP region as a whole is currently almost self-sufficient, with low net electricity imports, however, there is large variation among countries. The 'no target' scenario shows that the region as a whole will become a net exporter in the short term and a net importer from 2030 onwards, importing around 13% of its electricity consumption in 2050. The 'delayed' scenario also results in a net exporter position over the short term, but over the long term both the 'delayed' and 'decarbonisation' scenarios show that the region as a whole can become close to self-sufficient by the end of the modelled period as a result of increased investment in renewable generation. The net import positions of the individual countries within the region vary significantly. Some countries, such as Albania, become significant net exporters by the end of the modelled period under all scenarios, driven by the comparative competitiveness of hydro based generation, while Serbia will be a significant net importer. The net import position of individual countries is driven by very small differences in wholesale prices between the countries and can change significantly from one year to the next due to small price fluctuations. The regional net import position is

FIGURE 7
UTILISATION RATES OF CONVENTIONAL GENERATION IN THE SEERMAP REGION, 2020-2050 (%)



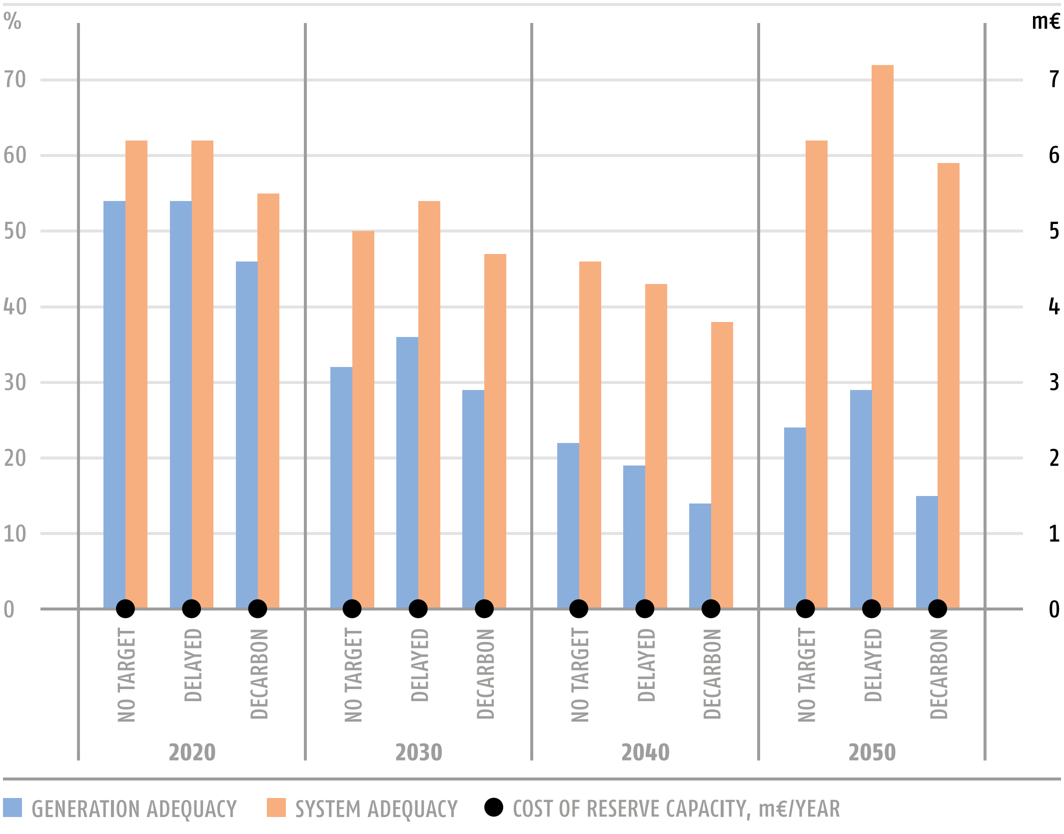
more stable with the electricity price spread between the region and other neighbouring countries higher than the intraregional spread, as shown in Figure 13.

The utilisation rate of coal plants remains relatively stable and even increases until 2040, depending on the scenario. However, these utilisation rates are lower than current levels which are typically more than 70%. Utilisation rates drop below those generally needed for commercial viability in 'decarbonisation' scenarios from 2030 onwards, and drop to very low rates by 2050 in all scenarios. Gas utilisation rates increase in all scenarios initially and peak in 2045 in the 'no target', 2035 in the 'delayed' and 2040 in the 'decarbonisation' scenario. Utilisation rates drop to low levels, around 20%, by the end of the modelled period in both scenarios with a decarbonisation target. This implies that if there is an ambitious decarbonisation target, the cost of gas based investments made at the beginning of the modelled period can be recovered but investments made closer to 2040 may be stranded. However, utilisation rates differ across countries, resulting in different levels of stranded costs. Coal investments made at any time during the modelled time period will also result in stranded assets. This issue is discussed further in section 5.4.

5.2 Security of supply

While the physical and commercial integration of national electricity markets naturally improves security of supply, decision makers are often concerned about the extent and robustness of this improvement, particulary for energy systems with a high share of renewables. In order to assess the validity of these 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.

FIGURE 8
GENERATION AND SYSTEM ADEQUACY MARGIN FOR THE SEERMAP REGION, 2020-2050 (% OF LOAD)

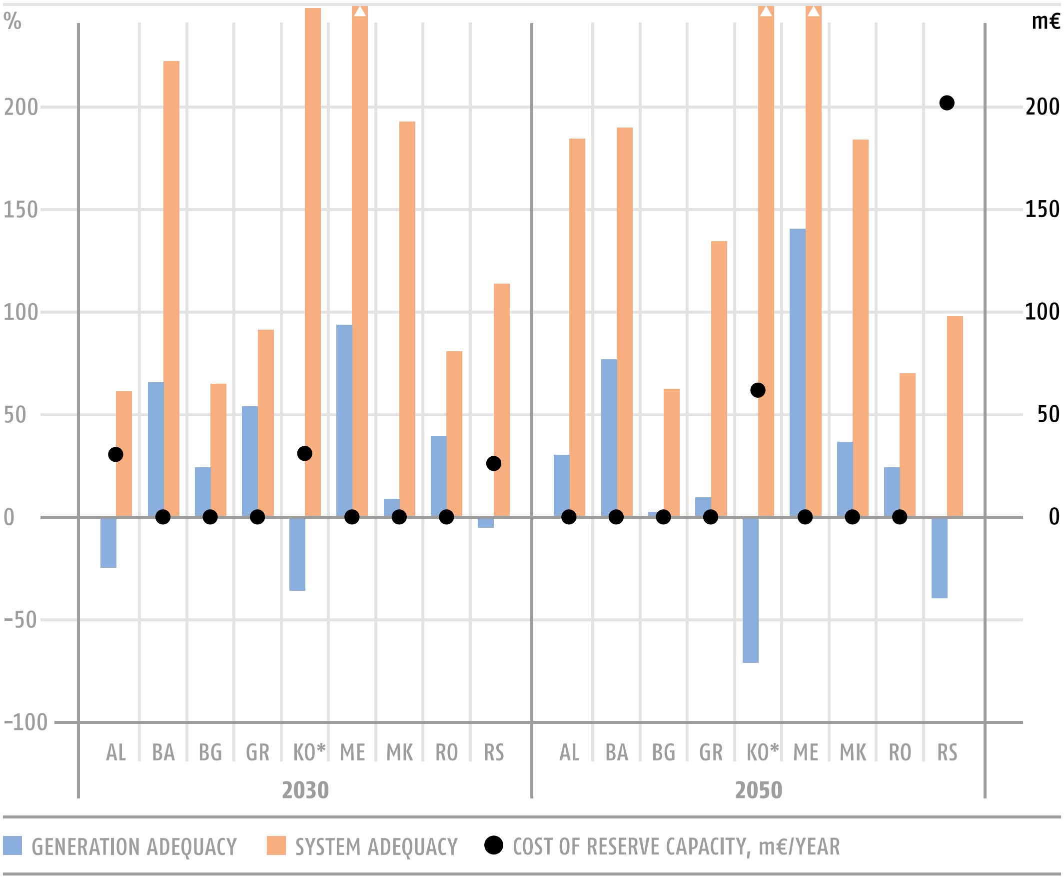


The generation adequacy margin is defined as the difference between available capacity and hourly load as a percentage of hourly load. If the resulting value is negative, the load cannot be satisfied with domestic generation capacities alone in a given hour and imports are needed. The generation adequacy margin was calculated for all of the 90 representative hours and the lowest value was used as the indicator. For this calculation, assumptions were made with respect to the maximum availability of different technologies. Fossil fuel power plants were assumed to be available 95% of the time, and hydro storage 100% of the time. For other RES technologies historical availability data was used. System adequacy was defined similarly but net transfer capacity available for imports is 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 (2015a), and previous SOAF reports)

For the SEERMAP region as a whole, the generation adequacy margin is positive throughout the modelling period, i.e. regional generation capacity is sufficient to satisfy regional demand in all hours of the year for all of the years shown. However, the generation adequacy margin is negative for some countries in some scenarios, in particular for Albania in 2020 and 2030 for all scenarios, for Kosovo* in 2040 and 2050 in the 'decarbonisation' scenario, and for Serbia for the entire period in the 'decarbonisation' scenario, and from 2035 onwards also in the other two scenarios. The system adequacy margin is higher than generation adequacy as it also accounts for import possibilities. Although there is significant variation among countries, the system adequacy margin is positive for all countries, enabling them to meet peak demand with their own generation capacity and imports at all times.

For negative generation adequacy indicators the cost of increasing the generation adequacy margin to zero was calculated. This is defined as the yearly fixed cost of an

FIGURE 9
GENERATION AND SYSTEM ADEQUACY MARGIN (% OF LOAD) AND COST OF RESERVE CAPACITY (m€/YEAR) FOR THE SEERMAP COUNTRIES ('DECARBONISATION' SCENARIO) 2030 AND 2050



open cycle gas turbine (OCGT) which has adequate 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 generation adequacy margin to zero.

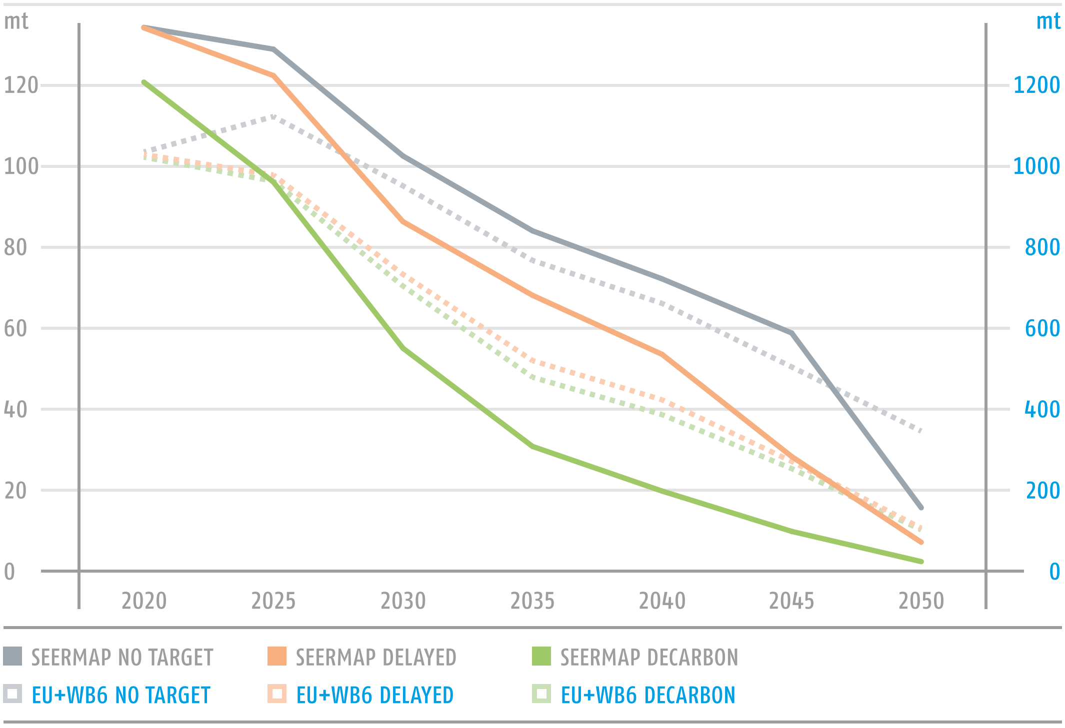
As the generation adequacy margin for the SEERMAP region as a whole is positive in all years for all scenarios, this cost for the region as a whole is zero. The country based adequacy margins are included in Figure 9 for the 'decarbonisation' scenario, showing that system adequacy values are positive for all countries. In 3 of the 4 countries where this value is negative, in Albania, Kosovo* and Serbia, the cost of increasing the generation adequacy margin to zero from an initial negative value is particularly high in the 'decarbonisation' scenario in some years. In Bulgaria, the value is high for the 'delayed' scenario in the second half of the modelled time period. This highlights the importance of regional markets and interconnections as a way of reducing costs in scenarios with high shares of renewable generation.

5.3 Sustainability

The CO_2 emissions of the three core scenarios were calculated, but due to data limitations this did not account for other greenhouse gases and only considered emissions from electricity generation, not including emissions related to heat production from cogeneration. The calculations were based on representative emission factors for the region.

The 94% decarbonisation target for the EU28+WB6 region translates into a higher than average level of decarbonisation in the SEERMAP region for the electricity sector. By 2050

FIGURE 10
CO_2 EMISSIONS UNDER THE 3 CORE SCENARIOS IN THE SEERMAP REGION AND IN THE EU+WB6, 2020-2050 (mt)



regional CO_2 emissions are 95.9% and 98.7% lower than 1990 levels in the 'delayed' and 'decarbonisation' scenarios respectively. This is due to a relative advantage for renewable electricity generation in the region compared with the European electricity sector in general, despite higher WACC levels in the region than in the EU. The comparative advantage rests in hydro potential and solar irradiation when compared to other European countries.

Emissions are also reduced significantly in the 'no target' scenario, reaching a 90.8% reduction by 2050. This is driven by the high price of carbon which leads to a massive reduction in coal based generation over the last 5 years of the modelled period and eventually erodes the competitiveness of gas based electricity generation over the long term.

The high level of emission reduction in the 'no target' scenario is made possible on the one hand by decreasing utilisation rates of fossil fuel power plants, especially coal and lignite due to lack of profitability, and on the other hand by the availability and viability of low carbon generation capacities. Bosnia and Herzegovina, Bulgaria, Greece, and Montenegro all have coal capacities which will finish operation before the end of their commercial lifetime due to lack of profitability resulting in stranded costs. In addition, the high level of emission reduction is enabled by an approximately 67% share of renewables in total generation, 15% nuclear generation in power plants located in Romania and Bulgaria, a contribution from the 600 MW CCS coal plant in Kosovo* which was included in the model exogenously, and a higher reliance on imports (around 13%) compared to the other scenarios.

The emissions profile of the countries in the region vary, but in the 'delayed' and 'decarbonisation' scenarios emission reduction in all countries is very high. Three countries, Macedonia, Montenegro and Serbia have a zero emissions electricity sector by 2050 under the 'decarbonisation' scenario.

The share of renewable generation as a percentage of gross regional consumption in the 'no target' scenario is 30.6% in 2030 and 57.8% in 2050. In the 'delayed' and 'decarbonisation' scenarios the share of renewable generation is 85.6% and 83.2% in

FIGURE 11
WEIGHTED AVERAGE WHOLESALE ELECTRICITY PRICE IN THE SEERMAP REGION, 2020-2050 (€/MWh)

2050, respectively. Albania, Bosnia and Herzegovina and Montenegro have more than a 100% RES share in 2050 compared with domestic consumption in the 'decarbonisation' scenario due to electricity exports. In contrast, the RES share in Bulgaria and Romania is only 54% and 75% due to relatively higher cost of RES generation. In these countries decarbonisation is achieved in part due to the presence of nuclear generation.

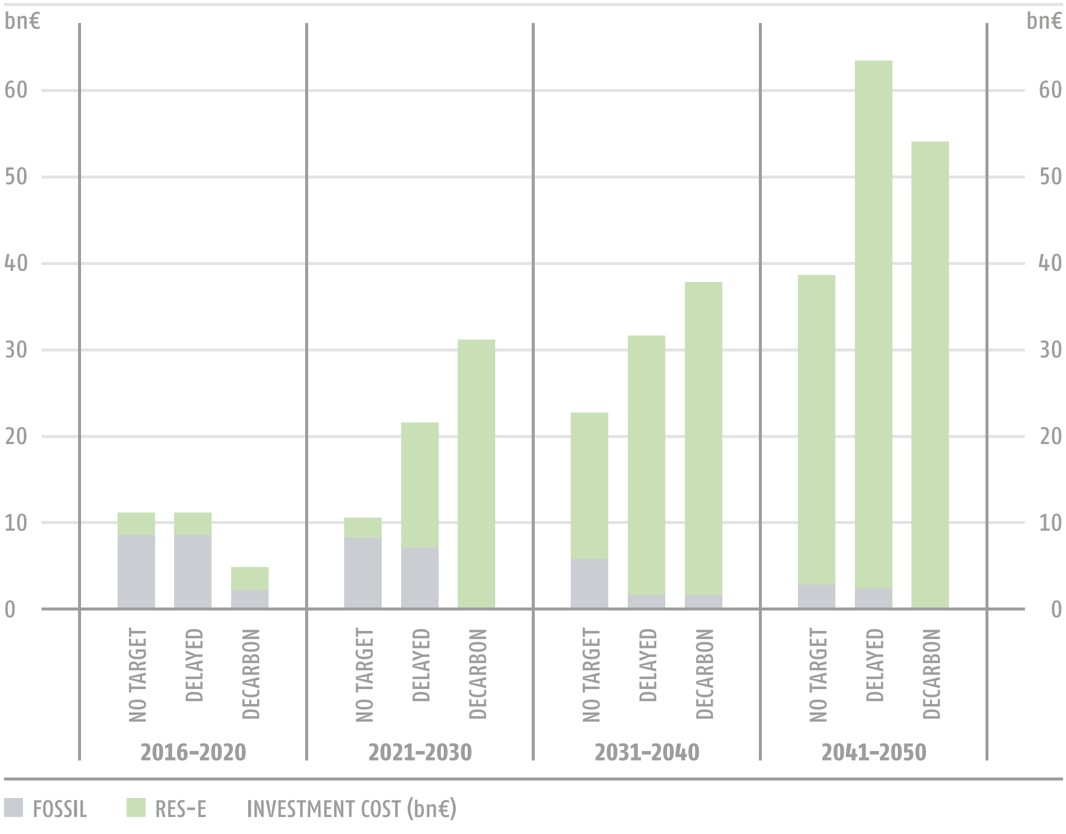
The utilisation of long term RES potential in the 'decarbonisation' scenario will reach 51% for hydro, 58% for wind and 53% for solar. However, some national potential is almost fully utilised by 2050, for example in the decarbonisation scenario in Albania, Kosovo*, Montenegro and Macedonia 91%, 85%, 85% and 87% of long term hydro potential is estimated to be utilised. In Bosnia and Herzegovina and Montenegro 90% and 88% of long term wind potential is utilised. These high level utilsation rates need to be revisited once the ongoing revision of the Hypropower Development Study in the Western Balkans is finalised.

5.4 Affordability and competitiveness

In the market model (EEMM) the wholesale electricity price is determined by the highest marginal generation cost of the power plants needed to satisfy demand. Over the modelled time period wholesale prices rise significantly, driven by an increasing carbon price and the price of natural gas. The price trajectories are independent from the level of decarbonisation and similar in all scenarios until 2045 when the two scenarios with a decarbonisation target result in lower wholesale prices. Nearing 2050, the share of low marginal cost 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 in addition to taxes, fees and network costs. It is therefore difficult to project retail price evolution based on wholesale price information alone, but it is likely that an increase in wholesale prices will affect affordability for consumers since it is a key determinant of end user price. The average annual price increase in the

FIGURE 12
CUMULATIVE INVESTMENT COST FOR 4 AND 10 YEAR PERIODS, 2016-2050 (bn€)



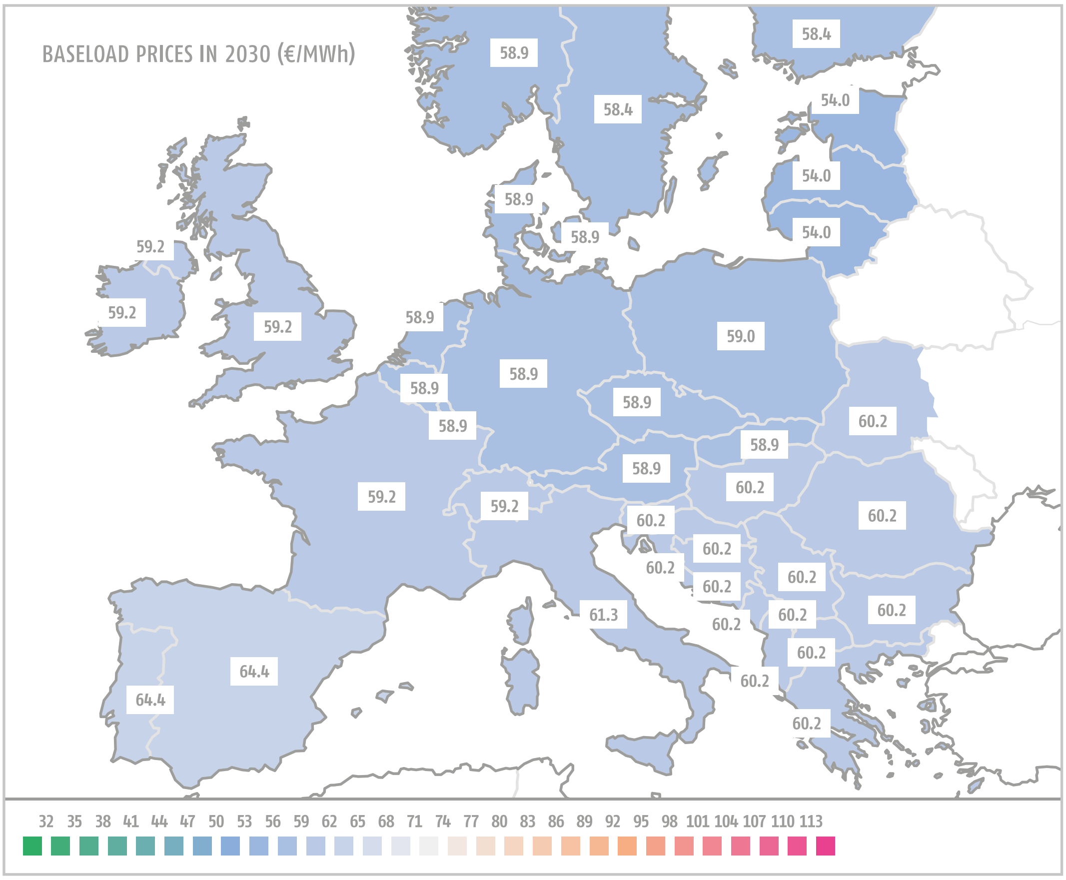
SEERMAP region over the entire period is 2.82% in the 'no target', 2.17% in the 'delayed' and 2.23% in the 'decarbonisation' scenarios.

There are slight differences between price levels of individual countries. The lower wholesale price increase in the two scenarios with a decarbonisation target are due to a fall in the wholesale price during the last 5 years of the modelled time period. Although the price increase is significant, it is important to note that 2016 wholesale electricity prices in Europe are at historical lows, 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 according to household electricity expenditure as a share disposable income, electricity remains affordable even with the price increase. Besides its negative effects, the price increase also has three positive implications, incentivising investment for new capacities, promoting energy efficiency and reducing the need for RES support.

The total regional investment needed in new capacities during the period until 2050 is lowest in the 'no target' scenario, at 83 bnEUR, and around 128 bnEUR in both the 'delayed' and 'decarbonisation' scenarios. (Investment needs do not account for investment costs of nuclear generation and investments in the transmission and distribution network.) Investment needs generally increase over the modelled time period in all scenarios due to the increasing share of new renewable capacities. As current investment levels in WB6 countries are far lower than these projections, the countries are likely to need exogenous support to mobilise funds for these investments in networks and RES generation. The EC can play crucial role in initialising this process.

It is important to note that investment is assumed to be financed by the private sector and based on a profitability requirement (apart from the capacities planned in

FIGURE 13
BASELOAD WHOLESALE PRICES IN EUROPE IN 2030 AND 2050 IN THE 'NO TARGET' SCENARIO



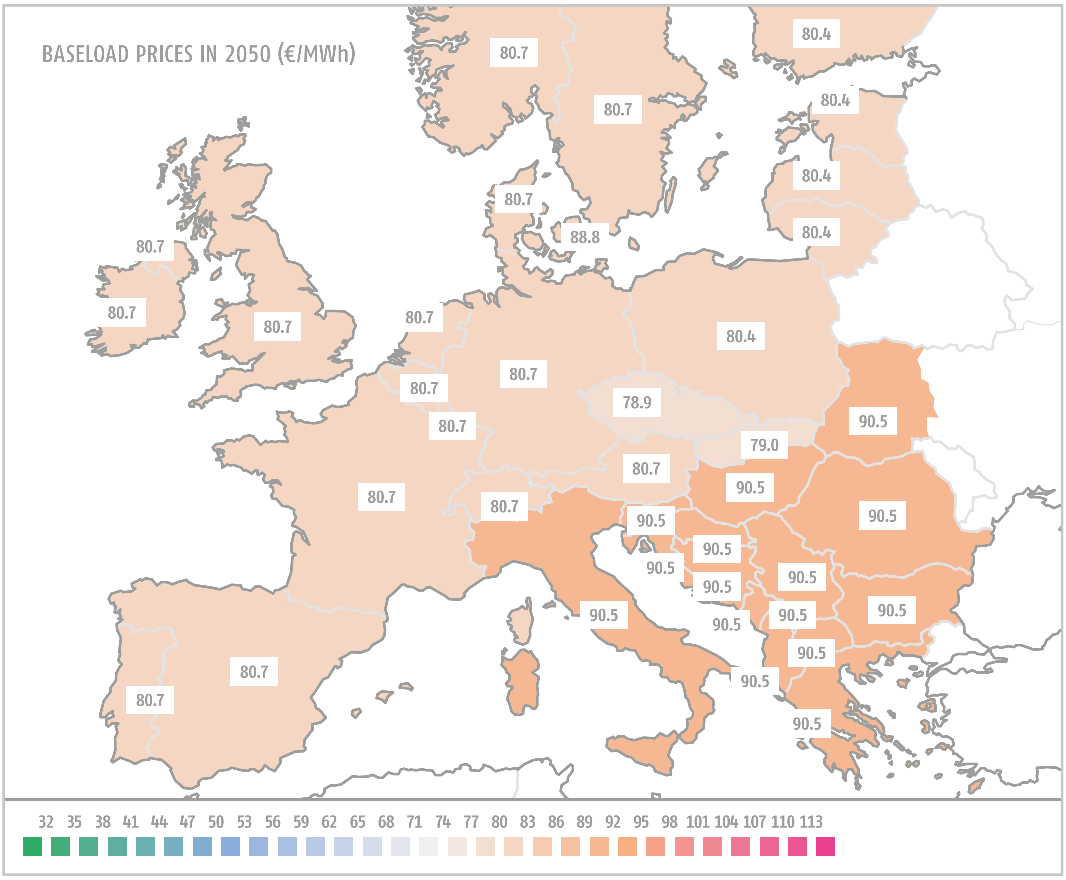
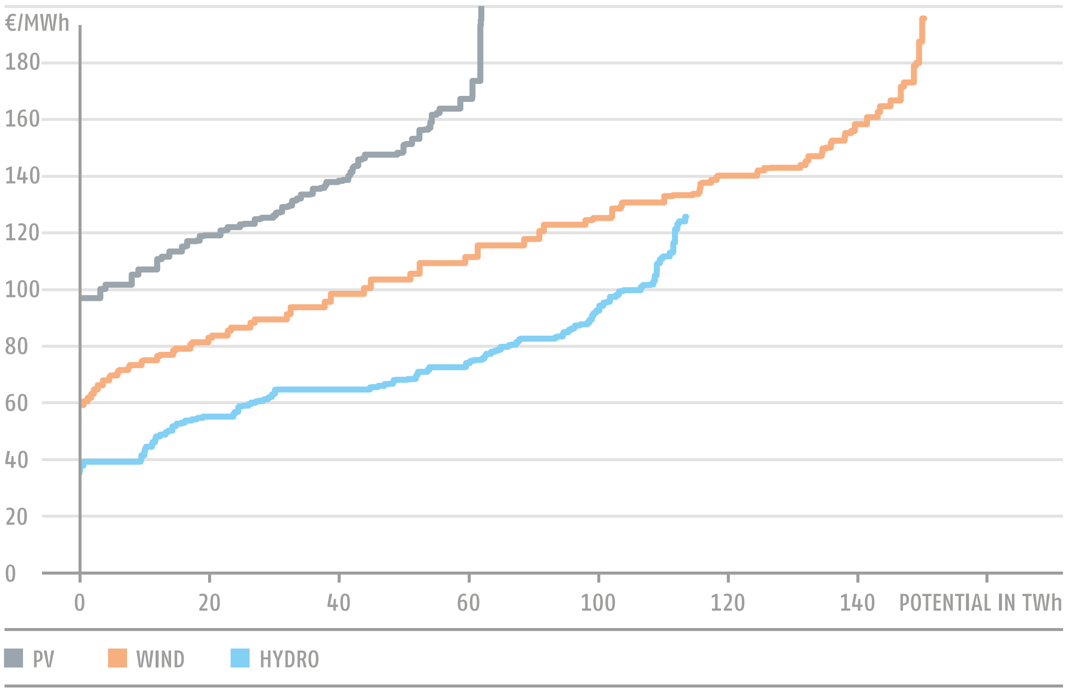


FIGURE 14
LONG TERM COST OF RENEWABLE TECHNOLOGIES (€/MWh)

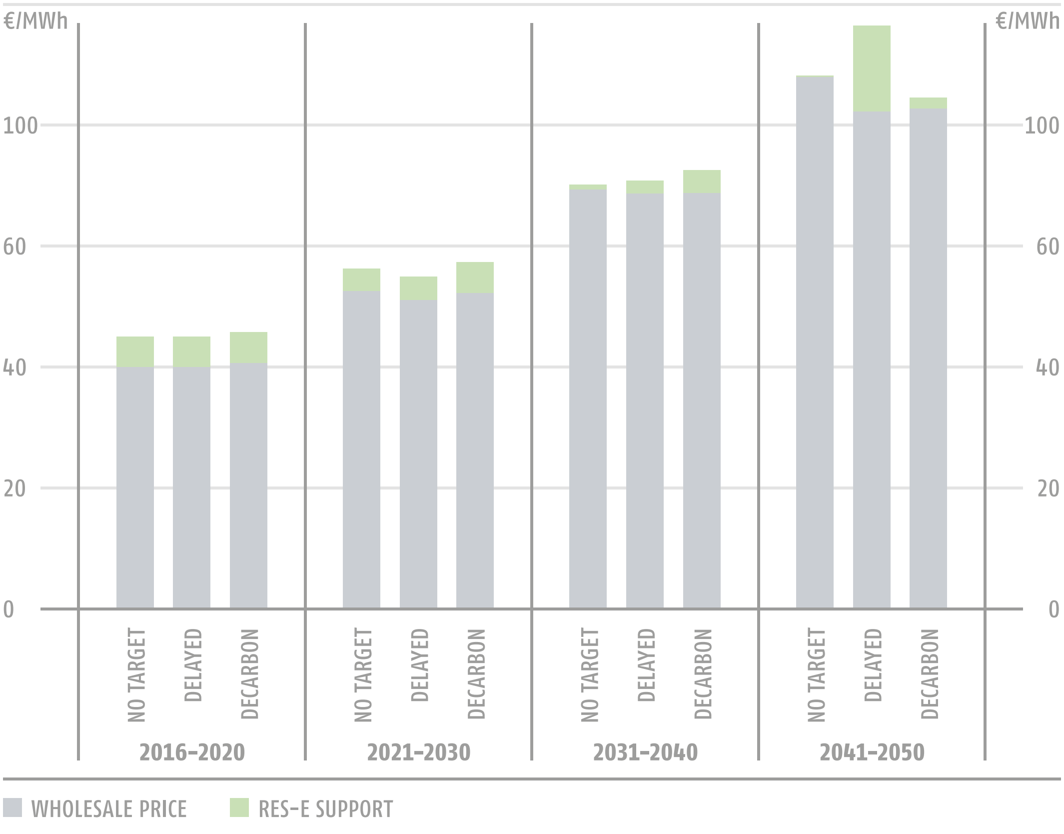


the national strategies). Here the different cost structure of renewables is important for the final investment decision, i.e. the higher capital expenditure is compensated by low operating expenditure. From a social welfare point of view, the consequences of the overall investment level are limited to the impact on GDP and a small positive impact on employment, as well as an improvement in the external balance. The technology choice affects electricity and gas imports, with higher share of renewables implying lower import levels. These impacts are discussed in more detail in section 5.7.

The price differentials within the modelled European countries depend on cross border network capacity constraints, which can prevent prices from equalising across all countries. The NTC values were taken from ENTSO-E sources, as indicated in section 4.2. Applying these NTC values, the forecasted demand profiles and the modelled electricity generation values, wholesale prices will be slightly higher in the SEERMAP region than in other EU countries in both 2030 and 2050, mainly as a result of the relatively higher gas prices in the region. This is due in part to the interconnection of the region with Italy, which drives prices up, and the capacity constraints along the northern borders of Italy, Slovenia and Hungary.

Despite the significant investment needs associated with the two emission reduction target scenarios, the renewables support needed to incentivise these investments decreases over time, with the exception of the 'delayed' scenario. The RES support needed to achieve almost complete decarbonisation in the 'decarbonisation' scenario relative to the wholesale price plus RES support is 10.8% in the period 2020-2025 but only 2.7% in 2045-2050. RES support decreases in the 'decarbonisation' scenario despite increasing investment in RES capacities, mostly because the rising wholesale electricity price reduces the need for additional support. Although some RES technologies have already reached grid parity, some support will still be needed in 2050 to stimulate new investment in each country in the two decarbonisation target scenarios. Since the best locations with highest potential are used first, it increases the levelised cost of electricity for new capacities. Technology learning on the other hand reduces LCOE, so the net impact is the result

FIGURE 15
WEIGHTED AVERAGE RES SUPPORT PER MWH OF TOTAL ELECTRICITY CONSUMPTION AND WEIGHTED AVERAGE WHOLESALE PRICE, 2016-2050 (€/MWh)



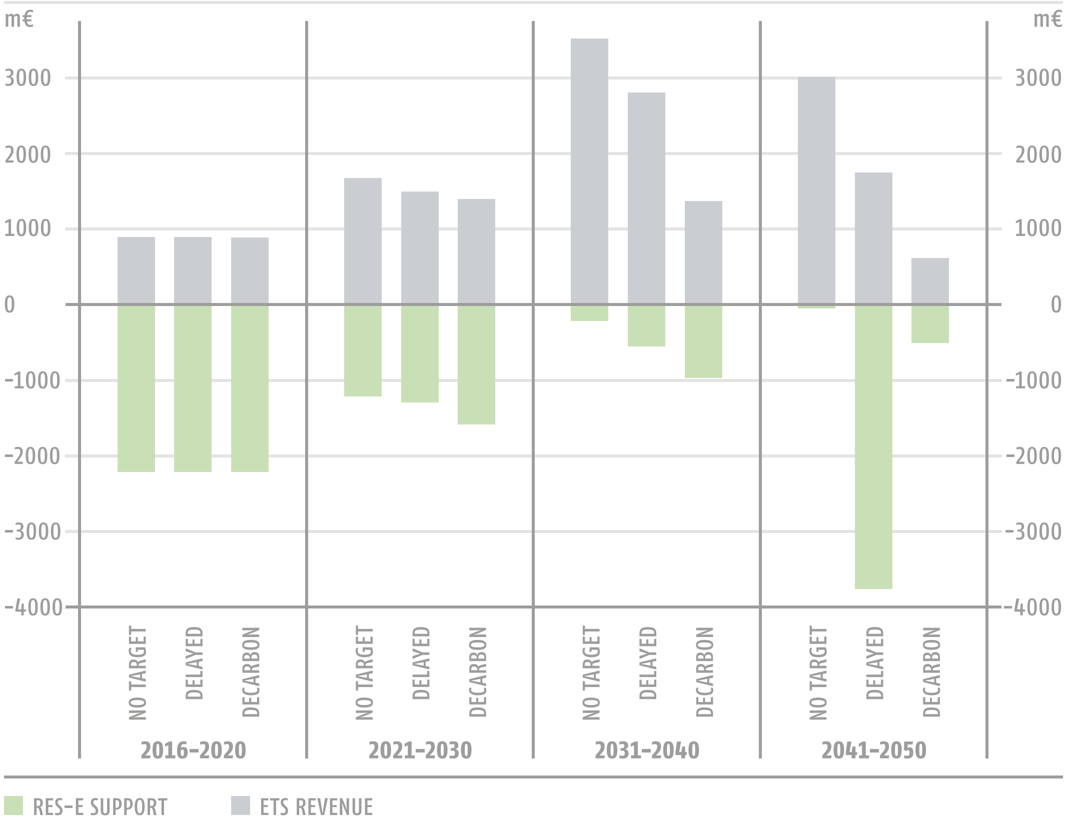
of these two opposing effects. The relationship between the cost of RES technologies and installed capacity is shown in Figure 14, but does not account for the learning curve adjustments which were embedded in the Green-X model).

The RES support needed in the 5 year period between 2045-2050 in the 'delayed' scenario is 24.3 EUR/MWh, compared with 2 EUR/MWh in the decarbonisation scenario, showing the high cost of delaying action on renewables.

Renewable energy investments may be incentivised through a variety of support schemes that secure funding from different sources, and in the model 'sliding' feed-in premium equivalent values are calculated. Revenue from the auction of carbon allowances under the EU ETS is one potential source of financing for renewable investment. Figure 16 compares cumulative RES support needs with ETS auction revenues, under an assumption of 100% auctioning and taking into account only allowances used in the electricity sector. The modelling results show that in the region as a whole ETS auctioning revenues are more than sufficient to cover the necessary RES support, with the exception of the last decade of the modelled time horizon in the 'delayed' scenario and the last five years in the 'decarbonisation' scenario. However, country level results can differ significantly, with auctioning revenues being lower than RES support needs in some countries for some years and scenarios.

A financial calculation was carried out to determine the stranded costs of fossil generation for plants that are built in the period 2017-2050. New fossil generation capacities included in the scenarios are defined either exogenously by national energy strategy documents or are built by the investment algorithm of the EEMM endogenously. The investment module projects 10 years ahead, meaning that investors have limited knowledge of the policies applied in the distant future. By 2050, the utilisation rate of coal generation assets drops below 15% and gas generation below 25% in most SEERMAP countries in the 'delayed' and 'decarbonisation'

FIGURE 16
ANNUAL AVERAGE RES SUPPORT AND AUCTION REVENUES FOR 4 AND 10 YEAR PERIODS, 2016-2050 (m€)



scenarios. 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.

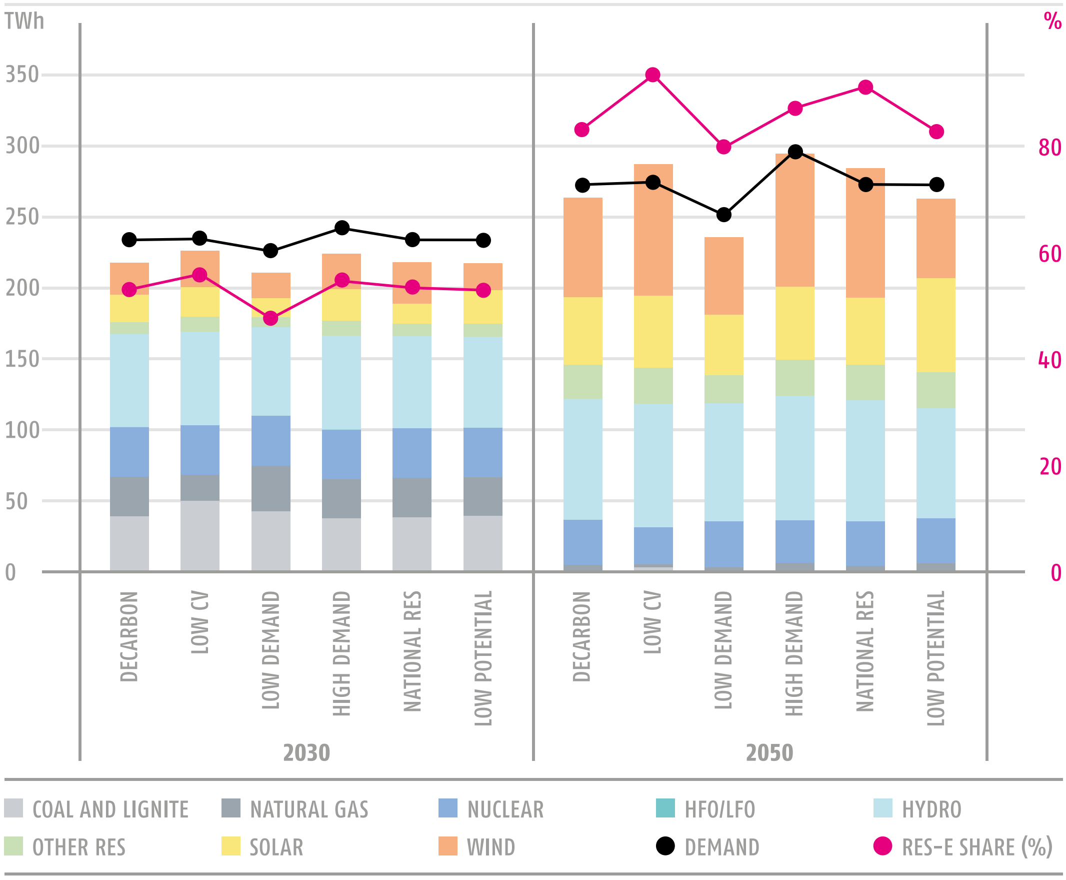
Large stranded capacities will likely require public intervention, whereby costs are borne by society/electricity consumers. Therefore, the calculation assumes that stranded cost will be collected as a surcharge on the consumed electricity (as is the case for RES surcharges) over a period of 10 years after these gas and coal capacities finish their operation. Based on this calculations early retired fossil plants would have to receive 2.6 EUR/MWh, 2.5 EUR/MWh and 0.6 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. Stranded costs are particularly high in Bosnia and Herzegovina, Greece and Kosovo* in both the 'no target' and 'delayed' scenarios.

5.5 Sensitivity analysis

In order to assess the robustness of the results, sensitivity analyses were carried out to test the following assumptions that were considered controversial by stakeholders during consultations:

- 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 assumed for the three core scenarios for the entire period until 2050. Lower carbon price coupled with CO_2 reduction target means higher RES investment requirement to compensate for the 'missing' decarbonisation effect;

FIGURE 17
GENERATION MIX, DEMAND (MWh), RES SHARE (% OF DEMAND) IN THE SENSITIVITY RUNS IN 2030 AND 2050



- Demand: the impact of higher and lower demand growth was tested, with a +/-0.25% change in the yearly growth rate for each year in all the modelled countries (EU28+WB6), resulting in a 8-9% deviation from the core trajectory by 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;
- National renewable electricity targets: the core scenarios had assumed that the RES target was defined at a regional level, whereas the sensitivity analysis tested the impact of setting national rather than regional RES targets.

The adjustments were only applied to the 'decarbonisation' scenario since this is the scenario that represents a significant departure from current policy for many countries. Therefore, it is 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. A 50% reduction in the value of the carbon price reduces the wholesale price by a third over the long term. However, in order to ensure that the same decarbonisation target is met, the required RES support is almost four times as high in this run than in the 'decarbonisation' scenario. Because of this, the sum of the wholesale price and RES support is higher than in the 'decarbonisation' scenario in all countries with the exception of Serbia, indicating the important role that the carbon price plays in incentivising a shift towards a low carbon electricity sector. The sensitivity assessment shows that the level of carbon price and the required RES support are linked to each other and should be optimised jointly for a cost efficient policy outcome.

- A lower carbon price would increase the utilisation rates of coal power plants by 10% in 2030 and more than 20% in 2050 compared with the 'decarbonisation' scenario. However, this increase in utilisation rates is not enough to make coal competitive by 2050.
- Gas utilisation rates fall with lower carbon prices due to stronger competition from coal based generation.
- Changing demand has only a limited impact on fossil fuel based capacities and generation. RES capacities and generation, in particular wind, are more sensitive to changes in demand.
- Lower hydro and wind potential leads to increased PV based capacity and generation. It also results in significantly higher RES support needs, which are more than four times the support levels needed in the 'decarbonisation' scenario.
- National renewable electricity targets result in higher overall investment and RES generation than regional targets. However, although RES generation in the region is only around 10% higher, the total support needed to achieve national targets is twice as high over the entire modelling period as in the case of a regional support framework. National targets are therefore less cost-effective than regional targets. However, the picture is less clear when we look at each country's contribution to RES support; if regional targets are combined with national support schemes then some countries will contribute more to overall support levels than under a national scheme. A regional target therefore warrants some sort of regional support scheme to ensure that the benefits of a regional target are distributed among all countries within the region.

5.6 Network

The transmission systems in the SEERMAP region are historically well-connected since the former Yugoslav Republics had strong interconnections with each other. In the future, additional network investments are expected to facilitate higher RES integration and cross-border electricity trade and to account for significant growth in peak load. The recorded peak load for the region in 2016 was 37 749 MW (ENTSO-E DataBase), while it is projected to be 42 429 MW in 2030 (SECI DataBase) and 49 760 MW in 2050. Consequently, domestic high voltage transmission and distribution lines will need significant investments in the future in most of the SEERMAP countries.

For the comparative assessment, a 'base-case' network scenario was constructed according to the SECI (Southeast European Cooperation Initiative) 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'.

The network analysis covered the following ENTSO-E impact categories: contingency analysis, TTC and NTC assessment and network losses.

Analysis of the network constraints anticipates contingencies in the SEE region. These problems can be solved by investments into the transmission network – e.g. by building additional lines or improving substations – where investment costs are estimated based on benchmark data for the region. The following two tables show where overloading and tripping can occur due to the changing production pattern in the SEE region envisaged in the 'delayed' and 'decarbonisation' scenarios in the years 2030 and 2050.

As the tables illustrate, tripping and overloading could occur in some specific areas, where the changing generation pattern – mainly due to new RES generation – would

TABLE 1 | TRIPPINGS AND OVERLOADINGS DETECTED IN THE SEERMAP COUNTRIES TRANSMISSION SYSTEM, 2030

Scenario	Tripping	Overloading	Solution	Units (km or pcs)	Cost m€
Delayed scenario	OHL 220 kV Fierza(AL) – Titan(AL)	OHL220 kV VauDejes(AL) – Komani (AL)	New OHL 220 kV Komani(AL) – Titan (AL)	70	11.15
	Several contingencies	OHL 110 kV Alibunar – Pancevo (RS)	New OHL 110 kV Bela Crkva – Veliko Gradiste	35	2.80
	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 mm² to 240/40 mm²	65	6.50
	OHL 110 kV Bar (ME) – WPP Mozura (ME)	WPP Mozura must go out of operation	New OHL 110 kV Ulcinj (ME) – Virpazar (ME)	40	3.50
Decarbon scenario	OHL 220 kV Komani (AL) – Kolace(AL)	OHL220 kV VauDejes(AL) – Komani (AL)	New OHL 220 kV Komani – Titan (AL)	70	11.15
	Several contingencies	OHL 110 kV Brezna (ME) – Klicevo (ME)	New SS 400/110 kV Brezna for RESs collection	1	20.00
	Several contingencies	OHL 110 kV Alibunar – Pancevo	New OHL 110 kV Bela Crkva – Veliko Gradiste	35	2.80
	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 mm² to 390/65 mm²	65	8.50
	OHL 110 kV Bar (ME) – WPP Mozura (ME)	WPP Mozura must go out of operation	New OHL 110 kV Ulcinj (ME) – Virpazar (ME) and OHL 110 kV Virpazar – Golubovci – Podgorica 1	80	8.00
	OHL 110 kV Danilovgrad (ME) – HPP Perucica (ME)	OHL 110 kV HPP Perucica – Podgorica	New OHL 110 kV Vilusi (ME) - H.Novi (ME)	40	5.50
	New RESs	OHLs 110 kV in the area of Tulcea West (RO)	New single circuit OHL 400 kV Gadalin (RO) – Sucaeva (RO) enables RES penetration from WF	260	52.00
	New RESs	OHLs 110 kV in the area of Dobruja region (BG)	New 400kV double circuit OHL to accommodate 2000 MW, RES generation in N-E Bulgaria (Dobruja region)	70	25.00
	New RESs	Southern Aegean Interconnector (GR) AC submarine cables (150 kV or 220 kV)	2 converter SS + 270 km DC subm. Cable Connection Wind Farms with AC Substations at Levitha and Syrna. AC Submarine cable to connect Kinaros Offshore Wind Farm HiV sub station to the AC side of Levitha Converter SS	several HVDCs	1800.00
	New RESs	OHLs 110 kV in the area of east part of Romania with RESs	New 400kV double circuit OHL (one circuit wired) between existing substations, Smardan (RO) – Gutinas (RO)	140	65.00
	New RESs	OHLs 110 kV in the area of Dobruja region (BG)	New 400 kV 140km single circuit parallel to the existing one. Varna (BG) – Burgas (BG)	140	35.00

cause network problems. In the 'delayed' scenario additional transmission network costs are 24 and 64 mEUR in 2030 and 2050, for the 'decarbonisaiton' scenario these values are 233 and 132 mEUR (not including the value for Greece). These costs are not significant compared to the overall investment costs in RES generation capacities, and demonstrates that moderate investments in transmission line development will ensure that the network will not constrain significantly the higher level of RES deployment projected for the region. However, it has to be emphasised that these cost estimates only cover transmission network development and do not include the cost of the required development of distribution networks which could be significantly higher.

Total and Net Transfer Capacity (TTC/NTC) changes were evaluated between all bordering countries in the region 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 exactly) significantly influence NTC values between the neighbouring electricity systems. We can distinguish two opposite impacts of higher RES deployments on the NTC values. First, the high concentration of RES in a geographic area may cause congestion in the transmission

TABLE 2 | TRIPPINGS AND OVERLOADINGS DETECTED IN THE SEERMAP COUNTRIES TRANSMISSION SYSTEM, 2050

Scenario	Tripping	Overloading	Solution	Units (km or pcs)	Cost m€
Delayed scenario	TR 400/220 kV Fier (AL)	OHL220 kV Fier(AL) – RRasbull (AL)	New TR 400/220 kV Fier (AL)	1	3.00
			SS Skakavica (AL) + 400 kV OHLs (to Tirana (AL) and Prizren (KS) New HPP Skakavica is going to be connected to the OHL 400 kV Tirana (AL) – Prizren (KS)	130 + SS 400 kV	65.00
	OHL 400 kV RP Drmno(RS) –Smederevo(RS)	OHL 400 kV Pancevo(RS) – Beograd (RS)	Change of the Conductors and earthwires and OPGW across the Danube river with higher capacity (1km)	1	0.08
Decarbon scenario	TR 400/220 kV Fier (AL)	OHL220 kV Fier (AL) – RRasbull (AL)	New TR 400/220 kV Fier (AL)	1	3.00
	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	20.00
	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) 2nd line Due to large RESs scaling in Greece and large import of Serbia	90	31.00
			SS Skakavica (AL) + 400 kV OHLs New HPP Skakavica is going to be connected to this SS	130+SS 400 kV	65.00
	OHL 400 kV Elbasan (AL) – Fier (AL)	OHL220 kV Fier(AL) – RRasbull (AL)	Second line OHL220 kV Fier(AL) – RRasbull (AL)	80	12.00
	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) 2nd line Due to large RESs scaling in Romania and Greece and large import of Serbia	2	0.70

network, reducing NTCs and requiring further investment. Second, if RES generation replaces imported electricity it may increase NTC for a given direction.

The network assessment also analysed the changes in NTC values for 2030 and 2050, but no clear trend could be observed. Out of the 18 analysed borders, there are only four – Bulgaria-Serbia, Bulgaria-Romania, Albania- Kosovo*, Albania-Macedonia – where NTC change is always positive in the six cases that were examined (two scenarios, two years and two seasons). In three directions–Macedonia-Serbia, Albania-Greece and Bulgaria-Greece–the NTC change is always negative for the six cases. This leads to the conclusion that large RES triggers congestion and reduces trade options. But in the other 11 directions the picture is mixed and no clear trend can be observed in the NTC variations.

Transmission network losses are affected in different ways. For one, losses are reduced as renewables, especially PV, are generally connected to the distribution network. However, high levels of electricity trade observable in 2050 will increase transmission network losses. Figure 17 shows that in the 'decarbonisation' and 'delayed' scenario transmission losses decrease significantly compared to the 'base case' scenario.

As Figure 18 illustrates, higher RES deployment in the two scenarios reduces transmission losses significantly, between 100-300 MW in 2030 and between 300-500 MW in 2050 during the modelled hours. This represents a 1500 GWh loss variation in 2030 and over 1700 GWh in 2050 in the 'decarbonisation' scenario. The 'delayed' scenario represents lower loss reduction values compared to the 'decarbonisation' scenario, which indicates lower benefits in the 'delayed' scenario. If this is monetised using the base load wholesale electricity price, the concurrent benefits for TSOs are in excess of 130 mEUR for the 'decarbonisation' scenario in 2050.

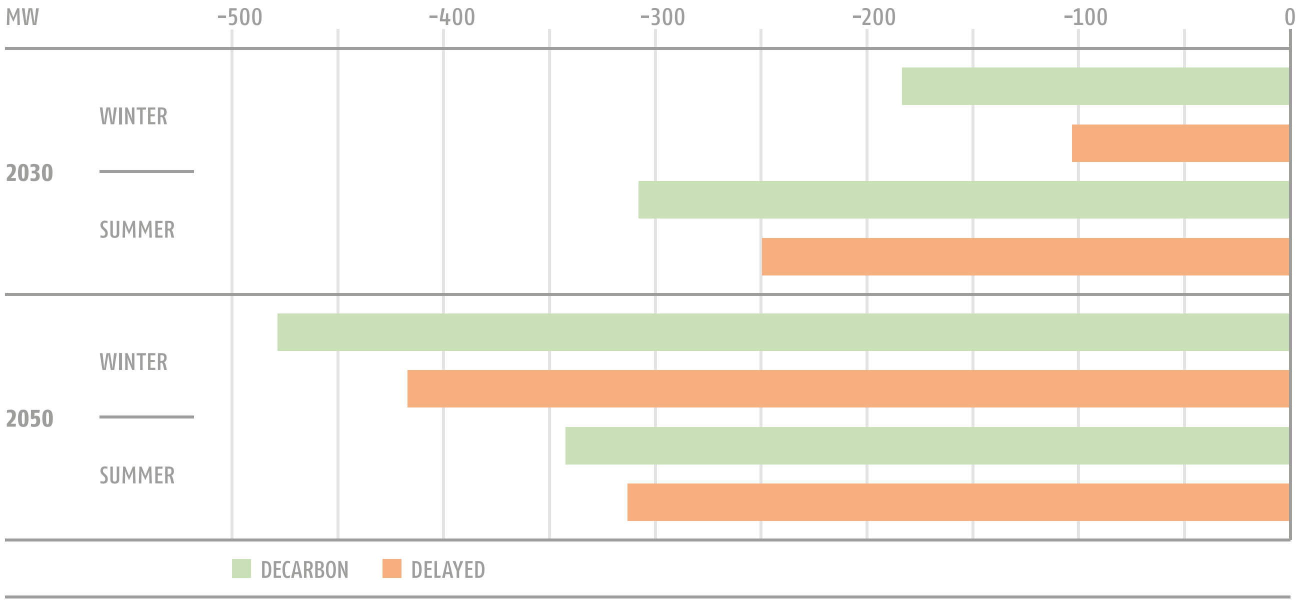


FIGURE 18 LOSS VARIATION COMPARED TO THE BASE CASE IN THE 'DELAYED' AND 'DECARBONISATION' SCENARIOS (MW, NEGATIVE VALUES INDICATE LOSS REDUCTION)

5.7 Macroeconomic impacts

A 'baseline' scenario which differs from the 3 core scenarios was constructed for the macroeconomic analysis, to serve as a basis for comparison. The 'baseline' scenario assumes that only power plants with a final investment decision by 2016 are built and that investment rates in the sector remain unchanged for the remaining period. No decarbonisation targets are set in this case, and no additional renewable support is assumed compared to currently existing policies. The 'baseline' scenario assumes lower levels of investment than the 3 core scenarios.

The 'baseline' scenario suggests that after an initial stronger performance at around 3% per annum, economic growth in the SEERMAP region slows down to 1.6% by 2020-2030 as countries converge towards the EU average in terms of GDP per capita. Individual country results differ substantially from the average region-wide tendency; 5 smaller economies grow above 2% per annum on average over the whole projection horizon, while the rest, most notably Greece and Bulgaria, have much weaker performance of 1.5%. Employment is projected to stagnate in most countries, with the exception of Greece and Macedonia. After significant efforts to improve the fiscal balance, both public and external debt could stabilise at around 60% of GDP.

In the 'baseline' scenario household electricity expenditure relative to disposable income is projected to increase from the current 2.5% to around 3%, partly because the growth of electricity prices causes a growth in expenditure which is higher than the expansion of households real disposable income. Household electricity expenditure to income will increase in 8 out of the 9 countries in the region, while it will decline visibly in Greece.

Government and external debt will remain broadly unchanged in most countries that are characterised by a low initial debt level. Nonetheless there are some exceptions: both public and external debt will decline substantially in Greece from exceedingly high initial levels. Additionally, there is a sizable decline in external debt in Montenegro, with more moderate declines registered in Bulgaria, Macedonia, Romania and Serbia. In terms of public debt, in addition to Greece, Albania, Bosnia and Herzegovina, Bulgaria and Montenegro also show a moderate decline.

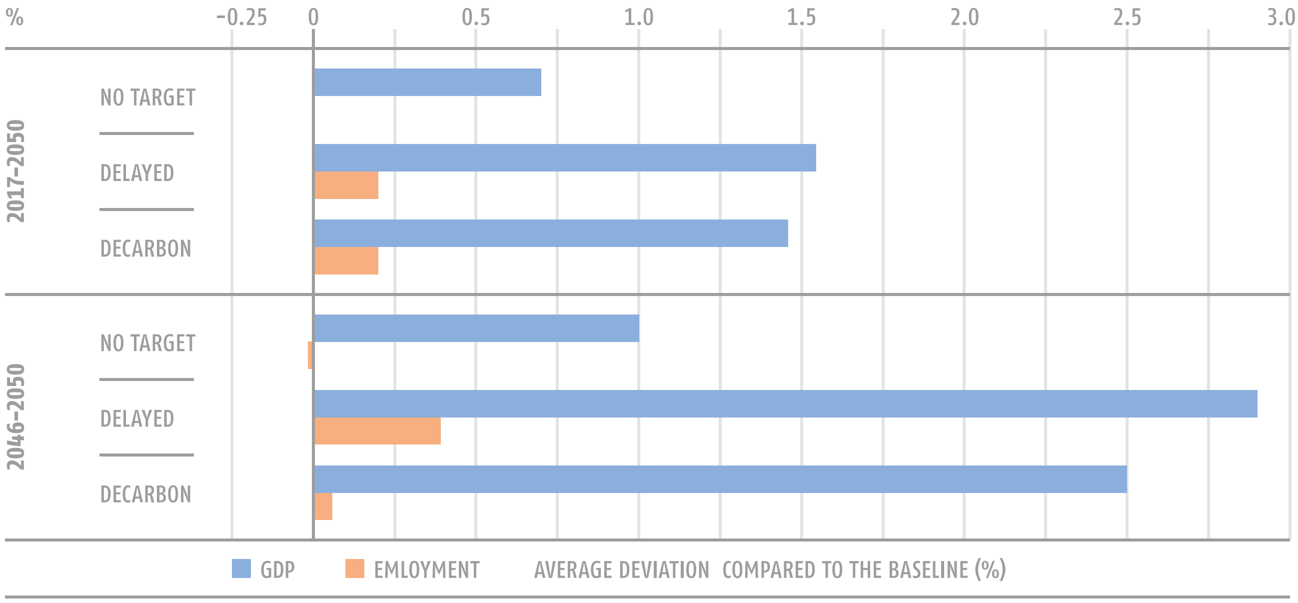


FIGURE 19
GDP AND EMPLOYMENT IMPACTS COMPARED WITH THE 'BASELINE' SCENARIO

All three core scenarios imply a moderate increase in investment compared to the 'baseline' scenario. Even in the most investment intensive periods, the net additional investment is below 0.5% of GDP. In the case of the 'no target' scenario, most of the additional investment is concentrated before 2025 compared with the 'baseline' scenario, while in the 'decarbonisation' scenario the intensive period starts after 2020 and remains relatively consistent. In the 'delayed' scenario there are two investment peaks: the initial period and from 2030 onwards.

The macroeconomic results were assessed along three dimensions. 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 2046-2050 period. It is important to stress that because the population remains the same across scenarios GDP gains are also reflected in the GDP per capita changes.

The three core scenarios suggest moderate macroeconomic gains with GDP increasing by 0.7-1.5% over the whole projection horizon. Long term (2046-2050) gains are higher, in the range of 1-2.5%. The gains are highest in the 'delayed' scenario and lowest in the 'no target' scenario. These differences primarily reflect the size of the investment efforts compared to the 'baseline' scenario. Long term GDP gains in the 'decarbonisation' and 'delayed' scenarios result 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.

Employment gains are much more muted, growing by less than 0.3% even in the scenarios with the highest GDP gains. 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 employment gains are translated into higher wages in the longer term, as labour supply remains the same across scenarios.

Similarly to the 'baseline' scenario, country results vary significantly. Effects tend to be larger for smaller economies (Bosnia and Herzegovina, Kosovo* and Montenegro), and less pronounced for larger ones (in particular Greece and Romania). Additionally, the

FIGURE 20
GDP EFFECTS AT THE COUNTRY LEVEL IN THE CORE SCENARIOS (2017-2050 AVERAGE)

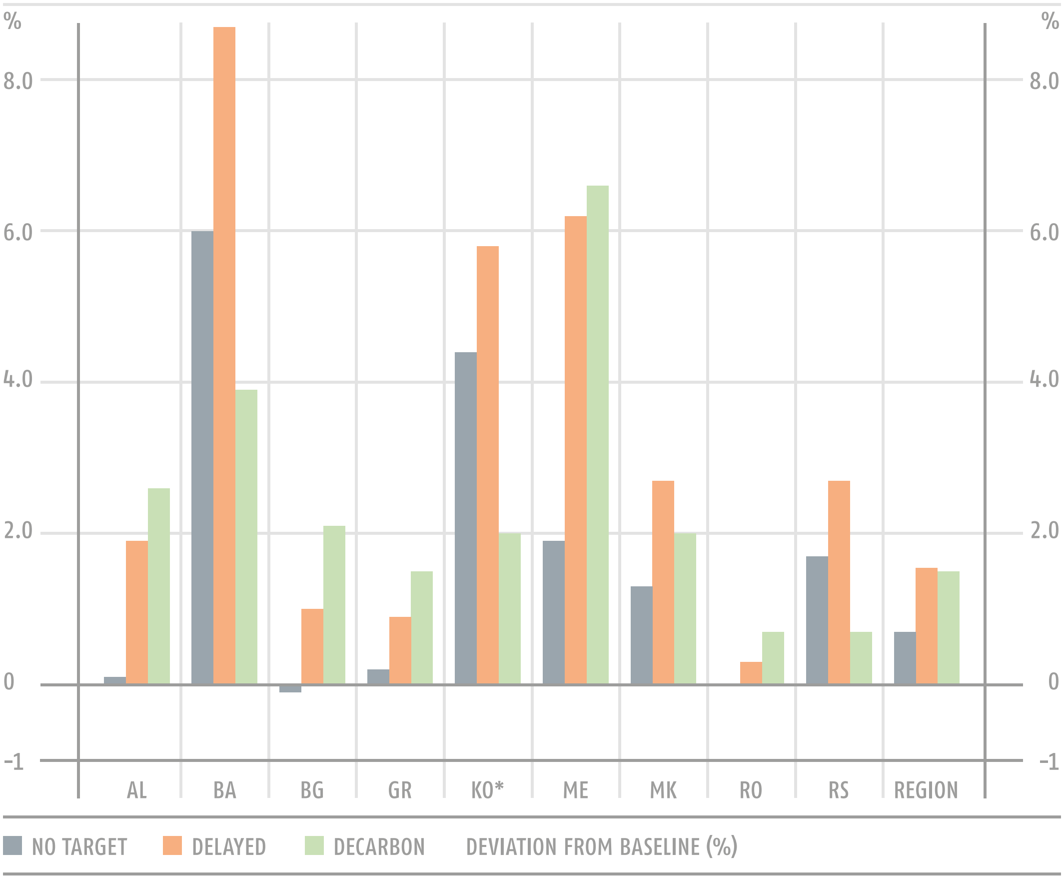


FIGURE 21
EMPLOYMENT EFFECTS AT THE COUNTRY LEVEL IN THE CORE SCENARIOS (2017-2050 AVERAGE)

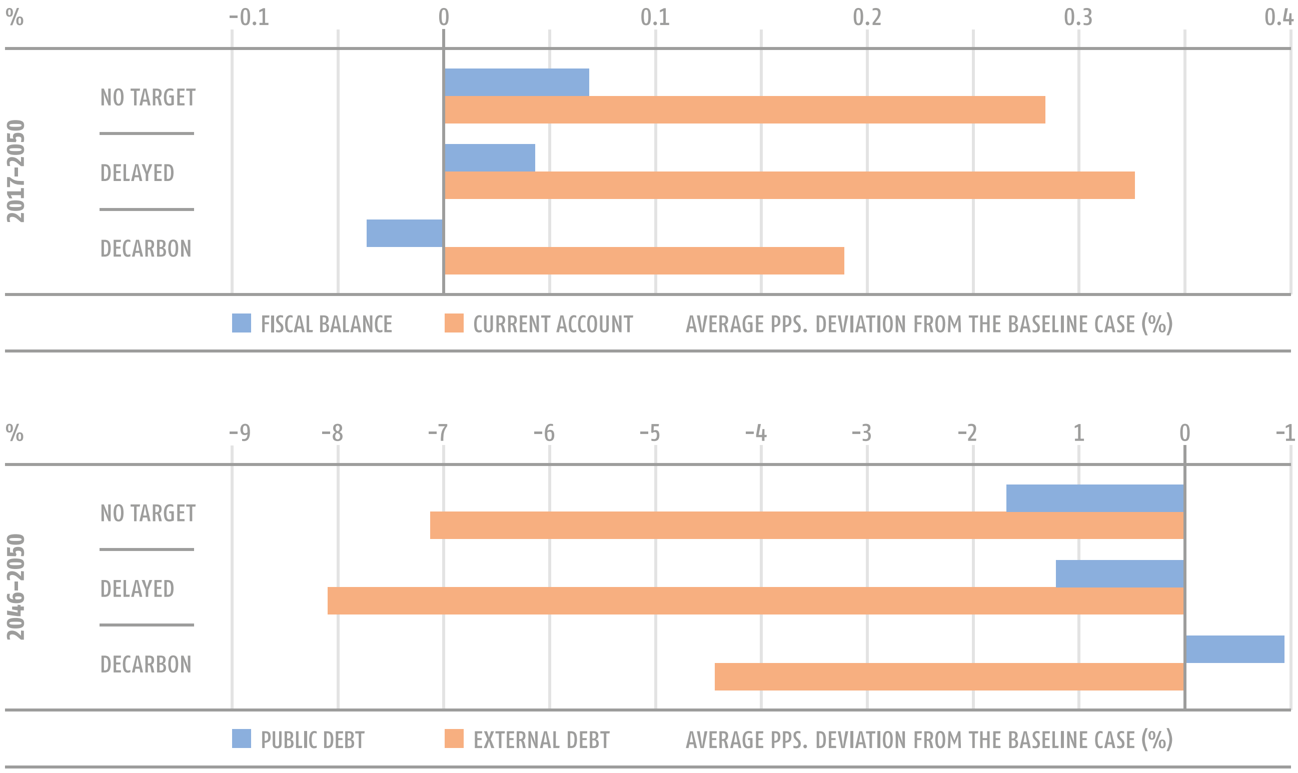


FIGURE 22
PUBLIC AND EXTERNAL BALANCES AND DEBT IMPACTS COMPARED WITH THE 'BASELINE' SCENARIO

sequencing of the macroeconomic gains are not consistent across scenarios: 5 out of the 9 countries experience the largest effects under the 'decarbonisation' scenario, for the rest of the countries the 'delayed' scenario shows the most gains. Additionally, the relative size of the GDP effect in the 'no target' and 'decarbonisation' scenarios vary from country to country. These differences depend on the relative size of the different types of energy investment as well as their implementation horizon.

Similarly to GDP gains, the 'decarbonisation' scenario also has the strongest employment effect in 5 out of 9 countries. This is mainly due to the fact that renewable deployment (most notably PV) has much higher employment intensity than traditional fossil plants.

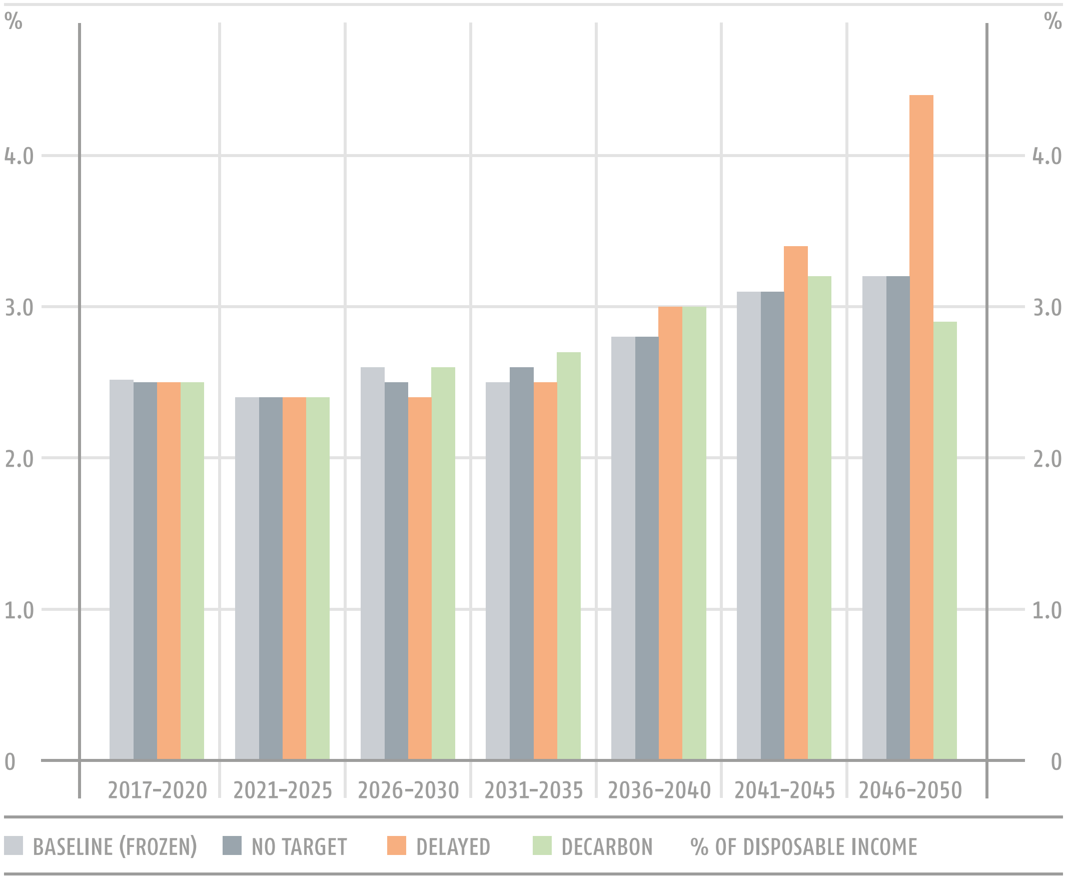
The macroeconomic vulnerability calculation captures how the additional investments contribute to the sustainability of the fiscal and external positions of the country. This is analysed according to the fiscal and external balances and the public and external debt indicators. While the fiscal and external 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 time horizon. This approach is consistent with the fact that debt is accumulated from past imbalances.

The three core scenarios generally decrease macroeconomic vulnerability as external debt tends to decline. Public debt decreases in the 'no target' and the 'delayed' scenarios, and only slightly increases in the 'decarbonisation' scenario. Nonetheless, overall effects are small; even the decline in external debt is hardly above 8% of GDP at the regional level.

The improvement in the external debt position is primarily the result of lower net electricity and gas imports for most countries. This effect is reinforced by higher GDP, which, ceteris paribus, decreases the debt to GDP ratio and hence the effective burden of the debt service.

Public debt positions are affected by two main factors. First, intensive fossil investments raise CO_2 related budget revenues in the 'no target' and 'delayed' scenarios, while

FIGURE 23
HOUSEHOLD ELECTRICITY EXPENDITURE FOR THE SEERMAP REGION



less fossil investment decreases such revenues in the 'decarbonisation' scenario. Second, higher GDP increases budget revenues and decreases public debt by a simple scale effect (lower effective debt service). In the 'no target' and 'delayed' scenarios all of these effects lead to a lower level of public debt than in the 'baseline' scenario. In the 'decarbonisation' scenario, the effect of lower CO_2 revenues has a slightly greater effect on the fiscal position than higher GDP has on fiscal revenues and public debt. However, there are some exceptions: in the case of Bulgaria and Romania, all scenarios will lead to lower CO_2 revenues, more public debt and consequently a worse fiscal balance.

Country results vary again, to a significant extent. Regarding the effect on the external debt positions, given that intensive investments for domestic energy production (and renewable technologies in particular) decrease net energy imports in most countries, the current account improves, and hence external debt is lower. This effect is reinforced by higher GDP which scales down the debt level. However, for Bulgaria in some scenarios net energy imports increase. Hence the current account deteriorates, and the higher GDP level cannot compensate for this effect.

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.

Generally, the average ratio of household electricity expenditure to disposable income at the regional level does not deviate substantially from the 'baseline' scenario. However, in the 'delayed' scenario the end of the projection horizon is characterised by around 35% higher expenditures caused by higher renewable subsidies during the period of 2046-2050. This effect is mitigated to a degree by lower wholesale energy prices. In the 'decarbonisation' scenario, electricity expenditure is around 10% lower compared to the 'baseline' towards the end of the modelled time horizon. Finally, there is only a small increase in the 'no target' scenario compared to the 'baseline', reflecting slightly higher real wholesale electricity prices.

6 | Policy conclusions

The modelling work carried out under the SEERMAP project identifies some key findings with respect to the different strategic choices in the electricity sector that countries in the SEERMAP region can take. We review these findings and suggest some policy relevant insights. **The analysis has uncovered robust findings relevant for all scenarios, from which no regret policy options can be identified.**

MAIN POLICY CONCLUSIONS

Regardless of whether or not countries in the SEERMAP region pursue an active policy to decarbonise their electricity sector, a significant shift from fossil fuels to renewables will take place:

- Countries in the SEERMAP region will, due to aging power plants, need to replace around 95% of their existing fossil fuel generation fleet by 2050;
- Results show that the replacement of current capacities will result in a large increase of renewable and disappearance of fossil based generation, with the exception of natural gas;
- The renewable share is almost 60% in the 'no target' and more than 80% in the 'delayed' and 'decarbonisation' scenarios in 2050;
- Lignite electricity generation will account for only 3-4% by 2050 in all scenarios, regardless of active renewable policies;
- Natural gas plays a transitional role on the path towards low carbon generation;
- The high penetration of renewables in all scenarios suggests that energy policy, both at the national and regional level, should focus on enabling RES integration;
- High renewable penetration does not compromise regional energy security.

Decarbonisation is worth it:

- The 'decarbonisation' scenario demonstrates that it is technically possible to reach decarbonisation targets suggested by the EU 2050 Roadmap in the SEERMAP region due to high RES potential;
- Decarbonisation does not drive wholesale prices up relative to other scenarios with less ambitious RES policies, but on the contrary, it reduces them after 2045;
- The macroeconomic analysis shows that despite the high absolute increase in wholesale electricity prices, household electricity expenditure relative to household income will only increase slightly, this increase is unavoidable in the 'no target' scenario as well;
- Decarbonisation reduces the cost of stranded investments by more than 75% from 2.5-2.6 EUR/MWh to 0.6 EUR/MWh in the region as a whole;
- The 'decarbonisation' scenario enables the region to reduce its reliance on imported fossil fuels, in particular natural gas, compared with the 'no target' scenario;

- Decarbonisation will require a significant increase in investment needs from about 83 bn EUR to about 128 bn EUR over the 35-year period under various scenarios, however:
  - Scenarios with a decarbonisation target exhibit higher GDP growth as well as higher employment levels;
  - Increased investment needs are balanced by reduced electricity and fuel imports resulting in a negligible positive effect on the fiscal balance and current account;
  - External debt is found to decrease by 4% over the long term in the region.

6.1 Main electricity system trends

The SEERMAP region will need to replace more than 30% of its current fossil fuel based generation capacity by the end of 2030, and more than 95% 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 countries in the region pursue an active policy to support renewable electricity generation, a significant replacement of fossil fuel based generation capacity will take place; coal and lignite based generation phase out gradually under all scenarios due to the increasing carbon price and oil disappears from the electricity mix by 2030.

Under scenarios with an ambitious decarbonisation target and corresponding RES support schemes, the region will have an electricity mix with around 83% renewable generation, mostly hydro and wind, and a significant share of solar by 2050. If renewable subsidies are phased out and no CO_2 emission target is set, as assumed in the 'no target' scenario, the share of RES in electricity consumption will reach approximately 58% in 2050, a significant increase on current levels.

The high penetration of RES in all scenarios suggests that a robust no-regret action for countries in the SEERMAP region is to focus on enabling RES integration. This involves:

- investing in transmission and distribution networks including cross border capacities,
- enabling demand side management and RES generation through a combination of technical solutions and appropriate regulatory practices, and
- promoting investment in storage solutions including those with regional relevance such as pumped hydro as well as small scale storage.

Natural gas will remain a relevant fuel source over the coming decades, with its utilisation for electricity generation growing in all scenarios initially. However, under a 'decarbonisation' scenario in line with the EU indicative decarbonisation target of 93-99% for the electricity sector, **the role of natural gas is transitory,** as gas plays only a very minor role by 2050. In this scenario total gas capacity decreases after 2020 new capacity does not fully replace outgoing capacity. This decreasing capacity is still sufficient to bridge the transition from fossil to renewable based electricity mix between 2025 and 2035 with higher utilisation rates. Under a scenario with no emission reduction target gas remains relevant even in 2050, but gas based generation peaks around 2035. In all scenarios gas capacity is concentrated in the EU3 countries.

If significant investments are made in gas based generation and infrastructure (as well as in coal based generation) this may result in stranded assets. Choosing to decarbonise the electricity sector with long term emission reduction targets in mind, as demonstrated by the 'decarbonisation' scenario, enables a 75% reduction of stranded costs in fossil based generation, but poses challenges such as addressing high RES penetration and increased investment needs.

Delayed action on renewables is feasible, but it has two disadvantages compared with a long term planned effort. It results in stranded assets in fossil based generation, including power plants which are currently planned. Translated into a price increase equivalent over a 10 year period, the cost of stranded assets is on par with the size of RES support needed for decarbonising the electricity sector. Assuming delayed action, **the disproportionate effort needed towards the end of the modelled period to enable the CO_2 emissions target to be met means a significant increase in RES support will be required.**

6.2 Security of supply

In both scenarios with a decarbonisation target, by the end of the modelled period the SEERMAP region produces approximately the same amount of electricity as it consumes. Generation and system adequacy indicators remain favourable; installed generation capacity within the region is sufficient to satisfy regional demand in all seasons and hours of the day throughout the modelled period.

However, there are differences between countries within the region. Analysis shows that, in particular, scenarios with a decarbonisation target in 2050 can result in negative generation adequacy for certain countries. In these countries increasing the generation adequacy margin to ensure that demand can be met at all times with domestic capacities would require additional investment in new capacities. This highlights the **importance of regional market integration and increasing the capacity of interconnections as a way of reducing generation investment costs** in scenarios with high shares of renewable generation.

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

The 'decarbonisation' scenario enables the region to significantly reduce its reliance on imported fossil fuels, in particular natural gas, by the end of the modelled period.

The network modelling results suggests that the need for transmission network investments are insignificant compared to the RES investment level. The present network assessment, however, does not provide any information on the investment need at distribution level.

6.3 Sustainability

The SEERMAP region has a high renewable potential, especially wind, hydro and solar which can be reaped through policies eliminating barriers to RES investment. **An important no-regret step involves de-risking policies addressing high financing cost and high cost of capital.** This would allow for cost-efficient renewable energy investment. Options for implementing regional level de-risking facilities may also be considered.

Regional cooperation towards the realisation of RES targets can significantly lower necessary RES support costs and reduce investment needs. A regional approach to renewables is therefore recommended, but in order to reach a win-win outcome for all involved countries, corresponding regional support mechanisms could also be explored.

6.4 Affordability and competitiveness

Decarbonisation of the electricity sector does not drive up wholesale electricity prices compared to a scenario where no emission reduction target is set. The wholesale price of electricity is not driven by the level of RES integration but by the CO_2 price, which is applied across all scenarios, and the price of natural gas, because natural gas based generation is the marginal plant needed to meet demand in a significant number of hours of the year.

The wholesale price of electricity follows a similar trajectory under all scenarios and only diverges after 2045. After this year, the wholesale electricity prices are lower in scenarios with high levels of RES in the electricity mix due to the low marginal cost of RES electricity generation.

The steady rise in wholesale electricity price has implications for affordability as it will likely translate into end user prices, but also helps to attract needed investment to replace outgoing capacity. Increasing electricity prices can be observed in the entire SEE region, and in fact all of the EU, in all scenarios for the modelled time period. In addition, **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 a strong growth in household disposable income.**

Decarbonisation will necessitate a very significant increase of investment in generation capacity. These investments are assumed to be financed by private actors who accept higher investment costs in exchange for lower operation (including fuel) and maintenance costs when making their investment decisions. From a social point of view, the high level of investment in the 'delayed' and 'decarbonisation' scenarios has a positive impact on GDP and a small positive impact on employment. At the same time, the external debt decreases by 8% of GDP in the long term as a result of the displacement of electricity and gas imports by a higher share of renewables, which improves the current account compared with the 'baseline' scenario.

Although not modelled, **wholesale price volatility of electricity is also expected to increase,** ceteris paribus, in a world with a high share of intermittent renewables. **Demand side measures and supply side measures such as increased storage capacity can constitute an appropriate policy response.** Over the long term policy decisions will need to be made on how to deal with price volatility, and what the acceptable level of price volatility is considering the costs of supply and demand side measures.

High initial investment needs for RES technologies imply that the profitability of the investment is very sensitive to the cost of capital, which is significantly higher in the SEE region than in the Western European member states, especially in Greece. Although much of the value of the cost of capital depends on country risk linked to the general macroeconomic conditions, **the cost of capital can be decreased to some extent through interventions by policy makers, first by ensuring a stable policy framework and second by putting in place de-risking measures. As outlined above, such measures are a no-regret step, as they yield minimal system costs and consumer expenditures.**

The need for RES support is limited by increasing electricity wholesale prices which incentivise significant RES investment even without support. At the level of the region on average auctioning revenues are more than sufficient to cover RES support needs, and although country level results differ, in all countries a potentially significant share of the RES support needed for decarbonisation of the electricity sector can be covered from EU ETS revenues. This can lower the burden of a high RES share on 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.

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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	24 154	21 338	15 520	10 980	7 426	2 360	1 472	693
		New	0	2 690	4 440	5 340	5 340	5 340	5 940	5 940
	Natural gas	Existing	8 855	8 150	7 827	6 922	5 350	3 398	2 113	0
		New	0	1 685	2 125	3 425	6 919	9 419	9 419	8 508
	Nuclear	Existing	3 413	3 413	3 413	3 413	3 413	3 413	3 413	3 413
		New	0	0	0	1 400	1 400	1 400	1 400	1 400
	HFO/LFO		2 229	2 045	1 580	284	284	0	0	0
	Hydro		21 756	23 091	23 512	24 178	25 346	27 216	28 982	30 523
	Wind		6 073	6 466	6 096	3 559	1 946	5 905	11 234	20 050
	Solar		5 033	5 394	5 394	5 396	4 498	8 105	15 574	22 685
	Other RES		270	615	770	981	1 195	1 615	2 392	3 118
Gross consumption, GWh			212 529	224 791	229 910	234 516	242 315	251 977	260 582	272 411
Net electricity generation, GWh	Total		211 614	231 455	247 309	233 420	232 430	245 960	264 374	236 653
	Coal and lignite		97 836	109 030	99 460	79 162	57 565	46 047	39 243	8 442
	Natural gas		17 126	22 326	47 249	47 422	67 875	73 013	68 216	35 600
	Nuclear		24 739	24 739	24 739	35 079	35 079	35 079	35 079	35 079
	HFO/LFO		2 132	2 105	1 684	0	0	0	0	0
	Hydro		50 157	51 495	52 487	54 392	57 959	63 598	70 077	75 781
	Wind		12 234	13 065	12 416	7 222	3 745	11 449	21 944	39 746
	Solar		6 091	6 399	6 399	6 403	5 436	10 171	19 608	28 300
	Other RES		1 299	2 296	2 875	3 739	4 770	6 602	10 208	13 706
Net import total, GWh			915	-6 664	-17 399	1 096	9 886	6 017	-3 792	35 758
Net import ratio, %			0.4%	-3.0%	-7.6%	0.5%	4.1%	2.4%	-1.5%	13.1%
RES-E share (RES-E production/gross consumption, %)			32.8%	32.6%	32.3%	30.6%	29.7%	36.4%	46.8%	57.8%
Utilisation rates of RES-E technical potential, %	Hydro		na	na	na	na	na	na	na	45%
	Wind		na	na	na	na	na	na	na	32%
	Solar		na	na	na	na	na	na	na	30%
Utilisation rates of conventional power production, %	Coal and lignite		46.2%	51.8%	56.9%	55.4%	51.5%	68.3%	60.4%	14.5%
	Natural gas		22.1%	25.9%	54.2%	52.3%	63.2%	65.0%	67.5%	47.8%
	Nuclear		82.7%	82.7%	82.7%	83.2%	83.2%	83.2%	83.2%	83.2%
Natural gas consumption of power generation, TWh			33.48	42.49	88.10	87.27	121.74	128.42	118.96	62.37
Security of supply	Generation adequacy margin		53%	54%	41%	32%	27%	22%	26%	24%
	System adequacy margin		191%	206%	264%	244%	221%	192%	185%	187%
CO_2 emission	Emission, Mt CO_2		123.0	134.3	128.9	102.5	84.0	72.1	58.8	15.6
	CO_2 emission reduction compared to 1990, %		27.7%	21.1%	24.3%	39.8%	50.6%	57.6%	65.5%	90.8%
Price impacts	Electricity wholesale price, €(2015)/MWh		35.1	41.0	52.6	60.2	68.4	77.7	90.5	90.5
	Total RES-E support/gross consumption, €(2015)/MWh, five year average		na	5.1	3.3	4.2	1.2	0.4	0.3	0.1
	Revenue from CO_2 auction/gross consumption, €(2015)/MWh		3.0	5.1	6.4	14.6	14.6	14.3	15.6	5.0
Investment cost, m€/5 year period	Coal and lignite		na	7 007	4 473	2 254	480	0	2 390	0
	Natural gas		na	1 556	405	1 193	3 019	2 285	0	444
	Total Fossil		na	8 563	4 878	3 447	3 499	2 285	2 390	444
	Total RES-E		na	2 635	614	1 661	4 064	12 920	16 289	19 566
	Total		na	11 198	5 492	5 107	7 563	15 204	18 679	20 010
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		na	na	na	na	na	na	na	na
	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	24 154	21 338	15 520	10 980	7 426	2 360	1 472	693
		New	0	2 690	4 440	5 340	5 340	5 340	5 940	5 940
	Natural gas	Existing	8 855	8 150	7 827	6 922	5 350	3 398	2 113	0
		New	0	1 685	2 125	2 125	3 619	3 619	3 619	2 308
	Nuclear	Existing	3 413	3 413	3 413	3 413	3 413	3 413	3 413	3 413
		New	0	0	0	1 400	1 400	1 400	1 400	1 400
	HFO/LFO		2 229	2 045	1 580	284	284	0	0	0
	Hydro		21 756	23 091	25 221	26 057	27 432	29 648	31 448	33 558
	Wind		6 073	6 468	9 188	7 074	6 719	14 932	26 848	40 693
	Solar		5 033	5 394	9 618	9 716	9 914	18 111	27 612	38 145
	Other RES		270	611	1 160	1 460	1 763	2 548	3 606	4 779
Gross consumption, GWh			212 529	224 793	229 850	233 978	242 208	251 502	260 846	273 033
Net electricity generation, GWh	Total		211 608	231 265	250 108	225 739	220 297	238 157	258 912	278 857
	Coal and lignite		97 834	108 980	98 229	71 468	53 589	43 664	26 282	9 172
	Natural gas		17 122	22 198	33 308	27 528	35 300	25 945	16 793	4 053
	Nuclear		24 739	24 739	24 739	35 079	35 079	35 079	35 006	31 953
	HFO/LFO		2 132	2 105	1 684	0	0	0	0	0
	Hydro		50 157	51 495	57 665	60 106	64 491	71 222	77 806	84 674
	Wind		12 234	13 069	18 365	13 952	12 789	28 850	52 577	80 410
	Solar		6 091	6 399	11 750	11 865	12 163	22 443	33 745	45 795
	Other RES		1 299	2 280	4 368	5 742	6 887	10 954	16 703	22 800
Net import total, GWh			921	-6 473	-20 258	8 239	21 910	13 345	1 934	-5 824
Net import ratio, %			0.4%	-2.9%	-8.8%	3.5%	9.0%	5.3%	0.7%	-2.1%
RES-E share (RES-E production/gross consumption, %)			32.8%	32.6%	40.1%	39.2%	39.8%	53.1%	69.3%	85.6%
Utilisation rates of RES-E technical potential, %	Hydro		na	na	na	na	na	na	na	51%
	Wind		na	na	na	na	na	na	na	66%
	Solar		na	na	na	na	na	na	na	51%
Utilisation rates of conventional power production, %	Coal and lignite		46.2%	51.8%	56.2%	50.0%	47.9%	64.7%	40.5%	15.8%
	Natural gas		22.1%	25.8%	38.2%	34.7%	44.9%	42.2%	33.4%	20.0%
	Nuclear		82.7%	82.7%	82.7%	83.2%	83.2%	83.2%	83.0%	75.8%
Natural gas consumption of power generation, TWh			33.47	42.25	62.10	51.69	64.89	47.75	30.43	7.48
Security of supply	Generation adequacy margin		53%	54%	47%	36%	26%	19%	27%	29%
	System adequacy margin		191%	206%	281%	264%	254%	225%	220%	223%
CO_2 emission	Emission, Mt CO_2		123.0	134.2	122.4	86.3	68.1	53.5	28.2	7.0
	CO_2 emission reduction compared to 1990, %		27.7%	21.1%	28.1%	49.3%	60.0%	68.6%	83.4%	95.9%
Price impacts	Electricity wholesale price, €(2015)/MWh		35.1	41.0	50.6	58.9	67.0	80.2	87.1	73.0
	Total RES-E support/gross consumption, €(2015)/MWh, five year average		na	5.1	3.8	4.0	1.8	2.6	4.0	24.3
	Revenue from CO_2 auction/gross consumption, €(2015)/MWh		3.0	5.1	5.8	12.4	11.8	10.6	7.5	2.3
Investment cost, m€/5 year period	Coal and lignite		na	7 007	4 473	2 254	480	0	2 390	0
	Natural gas		na	1 556	405	0	1 185	0	0	0
	Total Fossil		na	8 563	4 878	2 254	1 665	0	2 390	0
	Total RES-E		na	2 625	11 770	2 676	6 777	23 216	29 243	31 865
	Total		na	11 188	16 648	4 929	8 441	23 216	31 634	31 865
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		na	na	na	na	na	na	na	na
	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	24 154	21 338	15 520	10 980	7 426	2 360	1 472	693
		New	0	500	500	500	500	500	500	500
	Natural gas	Existing	8 855	8 150	7 827	6 922	5 350	3 398	2 113	0
		New	0	1 007	1 007	1 007	2 807	2 807	2 807	2 174
	Nuclear	Existing	3 413	3 413	3 413	3 413	3 413	3 413	3 413	3 413
		New	0	0	0	1 400	1 400	1 400	1 400	1 400
	HFO/LFO		2 229	2 045	1 580	284	284	0	0	0
	Hydro		21 756	23 096	25 792	27 886	29 766	31 616	32 884	33 708
	Wind		6 073	6 468	10 299	11 592	13 798	18 205	26 308	35 977
	Solar		5 033	5 394	9 950	15 658	21 871	27 466	33 950	40 134
	Other RES		270	611	1 379	2 072	2 604	3 597	4 407	5 109
Gross consumption, GWh			212 529	224 721	229 744	233 784	242 634	251 710	260 873	272 787
Net electricity generation, GWh	Total		211 608	220 240	230 207	218 106	220 448	232 090	249 197	263 599
	Coal and lignite		97 834	94 082	70 643	39 088	16 897	9 563	3 340	763
	Natural gas		17 122	26 051	35 799	27 798	33 154	25 937	17 283	4 013
	Nuclear		24 739	24 739	24 739	35 079	35 079	35 079	34 423	31 854
	HFO/LFO		2 132	2 105	1 684	0	0	0	0	0
	Hydro		50 157	51 515	59 164	65 556	71 313	76 941	81 943	85 386
	Wind		12 234	13 069	20 675	22 902	26 644	35 027	51 075	70 104
	Solar		6 091	6 399	12 167	19 253	26 787	33 473	40 600	47 541
	Other RES		1 299	2 280	5 337	8 431	10 575	16 069	20 534	23 939
Net import total, GWh			921	4 481	-463	15 679	22 185	19 620	11 676	9 188
Net import ratio, %			0.4%	2.0%	-0.2%	6.7%	9.1%	7.8%	4.5%	3.4%
RES-E share (RES-E production/gross consumption, %)			32.8%	32.6%	42.4%	49.7%	55.8%	64.2%	74.4%	83.2%
Utilisation rates of RES-E technical potential, %	Hydro		na	na	na	na	na	na	na	51%
	Wind		na	na	na	na	na	na	na	58%
	Solar		na	na	na	na	na	na	na	53%
Utilisation rates of conventional power production, %	Coal and lignite		46.2%	49.2%	50.3%	38.9%	24.3%	38.2%	19.3%	7.3%
	Natural gas		22.1%	32.5%	46.3%	40.0%	46.4%	47.7%	40.1%	21.1%
	Nuclear		82.7%	82.7%	82.7%	83.2%	83.2%	83.2%	81.6%	75.6%
Natural gas consumption of power generation, TWh			33.47	49.57	67.43	52.44	60.62	47.43	31.06	7.37
Security of supply	Generation adequacy margin		53%	46%	37%	29%	23%	14%	17%	15%
	System adequacy margin		191%	145%	216%	222%	220%	188%	187%	190%
CO_2 emission	Emission, Mt CO_2		123.0	120.8	96.1	55.0	30.7	19.7	9.7	2.3
	CO_2 emission reduction compared to 1990, %		27.7%	29.0%	43.5%	67.7%	81.9%	88.4%	94.3%	98.7%
Price impacts	Electricity wholesale price, €(2015)/MWh		35.1	42.1	52.2	59.5	65.9	81.4	86.9	74.5
	Total RES-E support/gross consumption, €(2015)/MWh, five year average		na	5.1	3.6	6.6	4.5	3.0	1.6	2.0
	Revenue from CO_2 auction/gross consumption, €(2015)/MWh		3.0	5.1	5.9	7.9	5.3	3.9	2.6	0.7
Investment cost, m€/5 year period	Coal and lignite		na	1 306	0	0	0	0	0	0
	Natural gas		na	930	0	0	1 648	0	0	0
	Total Fossil		na	2 236	0	0	1 648	0	0	0
	Total RES-E		na	2 606	16 625	14 572	17 391	18 825	26 144	27 995
	Total		na	4 843	16 625	14 572	19 039	18 825	26 144	27 995
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		na	na	na	na	na	na	na	na
	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	24 154	21 338	15 520	10 980	7 426	2 360	1 472	693
		New	0	500	500	500	500	500	500	500
	Natural gas	Existing	8 855	8 150	7 827	6 922	5 350	3 398	2 113	0
		New	0	1 007	1 007	1 007	2 307	2 307	2 307	1 674
	Nuclear	Existing	3 413	3 413	3 413	3 413	3 413	3 413	3 413	3 413
		New	0	0	0	1 400	1 400	1 400	1 400	1 400
	HFO/LFO		2 229	2 045	1 580	284	284	0	0	0
	Hydro		21 756	23 031	25 933	28 170	30 265	32 184	33 597	34 643
	Wind		6 073	6 338	10 408	12 997	17 113	24 193	35 418	47 164
	Solar		5 033	5 394	10 882	17 035	23 242	29 533	35 146	43 904
	Other RES		270	623	1 693	2 496	3 207	4 005	4 888	5 426
Gross consumption, GWh			212 698	224 929	230 144	234 508	243 378	252 667	261 853	274 530
Net electricity generation, GWh	Total		213 540	219 959	226 751	226 212	235 018	242 745	265 925	287 368
	Coal and lignite		99 092	96 722	71 836	50 193	33 216	12 384	7 552	3 084
	Natural gas		17 830	23 608	28 517	18 010	18 940	16 771	9 294	2 347
	Nuclear		24 739	24 739	24 739	35 079	35 072	34 228	30 997	25 915
	HFO/LFO		2 113	2 105	1 684	0	0	0	0	0
	Hydro		50 157	51 276	59 322	66 078	72 514	78 292	83 549	87 138
	Wind		12 218	12 782	20 855	25 589	33 406	47 302	69 680	92 791
	Solar		6 091	6 399	13 341	20 898	28 100	35 333	41 577	50 811
	Other RES		1 299	2 327	6 457	10 365	13 769	18 435	23 275	25 282
Net import total, GWh			-842	4 970	3 393	8 297	8 360	9 922	-4 073	-12 838
Net import ratio, %			-0.4%	2.2%	1.5%	3.5%	3.4%	3.9%	-1.6%	-4.7%
RES-E share (RES-E production/gross consumption, %)			32.8%	32.4%	43.4%	52.4%	60.7%	71.0%	83.3%	93.3%
Utilisation rates of RES-E technical potential, %	Hydro		na	na	na	na	na	na	na	52.5%
	Wind		na	na	na	na	na	na	na	76.5%
	Solar		na	na	na	na	na	na	na	58.5%
Utilisation rates of conventional power production, %	Coal and lignite		46.8%	50.6%	51.2%	49.9%	47.8%	49.4%	43.7%	29.5%
	Natural gas		23.0%	29.4%	36.9%	25.9%	28.2%	33.6%	24.0%	16.0%
	Nuclear		82.7%	82.7%	82.7%	83.2%	83.2%	81.2%	73.5%	61.5%
Natural gas consumption of power generation, TWh			0	0	0	0	0	0	0	0
Security of supply	Generation adequacy margin		53%	46%	38%	31%	27%	17%	22%	21%
	System adequacy margin		191%	144%	216%	223%	222%	193%	191%	193%
CO_2 emission	Emission, Mt CO_2		124.5	122.7	94.6	64.8	44.5	19.7	11.4	4.0
	CO_2 emission reduction compared to 1990, %		26.8%	27.9%	44.4%	61.9%	73.9%	88.4%	93.3%	97.6%
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	5.2	7.3	13.8	15.1	15.5	17.7	35.0
	Revenue from CO_2 auction/gross consumption, €(2015)/MWh		0	0	0	13.2	12.1	5.6	3.7	3.0
Investment cost, m€/5 year period	Coal and lignite		na	1 306	0	0	0	0	0	0
	Natural gas		na	930	0	0	1 191	0	0	0
	Total Fossil		na	2 236	0	0	1 191	0	0	0
	Total RES-E		na	2 388	17 481	16 766	19 187	20 119	26 628	31 192
	Total		na	4 625	17 481	16 766	20 377	20 119	26 628	31 192
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		na	na	na	na	na	na	na	na
	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	24 154	21 338	15 520	10 980	7 426	2 360	1 472	693
		New	0	500	500	500	500	500	500	500
	Natural gas	Existing	8 855	8 150	7 827	6 922	5 350	3 398	2 113	0
		New	0	1 007	1 007	1 007	1 807	1 807	1 807	1 174
	Nuclear	Existing	3 413	3 413	3 413	3 413	3 413	3 413	3 413	3 413
		New	0	0	0	1 400	1 400	1 400	1 400	1 400
	HFO/LFO		2 229	2 045	1 580	284	284	0	0	0
	Hydro		21 756	23 094	25 506	26 955	28 739	30 276	32 022	32 896
	Wind		6 073	6 458	9 928	8 981	10 091	13 717	23 133	28 186
	Solar		5 033	5 394	9 809	11 066	12 807	20 664	29 421	36 025
	Other RES		270	611	1 300	1 695	1 973	2 417	3 529	4 160
Gross consumption, GWh			212 529	222 526	224 690	225 847	231 394	236 551	243 076	251 347
Net electricity generation, GWh	Total		211 603	218 324	227 613	210 688	204 813	205 896	225 624	235 846
	Coal and lignite		97 835	93 785	70 661	42 642	22 978	11 019	3 336	902
	Natural gas		17 125	24 458	35 274	32 209	35 321	24 813	11 620	2 359
	Nuclear		24 739	24 739	24 739	35 079	35 079	35 079	34 349	32 377
	HFO/LFO		2 132	2 105	1 684	0	14	0	0	0
	Hydro		50 157	51 507	58 275	62 680	68 159	73 002	79 402	83 119
	Wind		12 224	13 051	20 004	17 819	19 526	26 352	44 874	54 474
	Solar		6 091	6 399	11 994	13 522	15 671	25 377	35 430	42 909
	Other RES		1 299	2 280	4 982	6 736	8 065	10 254	16 614	19 705
Net import total, GWh			926	4 203	-2 923	15 159	26 581	30 655	17 451	15 501
Net import ratio, %			0.4%	1.9%	-1.3%	6.7%	11.5%	13.0%	7.2%	6.2%
RES-E share (RES-E production/gross consumption, %)			32.8%	32.9%	42.4%	44.6%	48.2%	57.1%	72.5%	79.7%
Utilisation rates of RES-E technical potential, %	Hydro		na	na	na	na	na	na	na	49.5%
	Wind		na	na	na	na	na	na	na	45.4%
	Solar		na	na	na	na	na	na	na	48.0%
Utilisation rates of conventional power production, %	Coal and lignite		46.2%	49.0%	50.4%	42.4%	33.1%	44.0%	19.3%	8.6%
	Natural gas		22.1%	30.5%	45.6%	46.4%	56.3%	54.4%	33.8%	22.9%
	Nuclear		82.7%	82.7%	82.7%	83.2%	83.2%	83.2%	81.5%	76.8%
Natural gas consumption of power generation, TWh			0	0	0	0	0	0	0	0
Security of supply	Generation adequacy margin		53%	47%	38%	28%	22%	11%	18%	16%
	System adequacy margin		191%	147%	218%	220%	215%	191%	194%	200%
CO_2 emission	Emission, Mt CO_2		123.0	119.8	95.9	60.8	38.6	21.0	7.8	1.8
	CO_2 emission reduction compared to 1990, %		27.7%	29.6%	43.7%	64.2%	77.3%	87.6%	95.4%	98.9%
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	5.1	4.6	5.3	2.9	0.4	0	0
	Revenue from CO_2 auction/gross consumption, €(2015)/MWh		0	0	0	12.6	8.4	5.4	2.0	1.1
Investment cost, m€/5 year period	Coal and lignite		na	1 306.1	0	0	0	0	0	0
	Natural gas		na	930.3	0	0	732.5	0	0	0
	Total Fossil		na	2 236	0	0	732	0	0	0
	Total RES-E		na	2 590	13 961	6 088	10 425	15 938	26 512	17 411
	Total		na	4 826	13 961	6 088	11 158	15 938	26 512	17 411
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		na	na	na	na	na	na	na	na
	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	24 154	21 338	15 520	10 980	7 426	2 360	1 472	693
		New	0	500	500	500	500	500	500	500
	Natural gas	Existing	8 855	8 150	7 827	6 922	5 350	3 398	2 113	0
		New	0	1 007	1 007	1 007	3 407	3 407	3 407	2 774
	Nuclear	Existing	3 413	3 413	3 413	3 413	3 413	3 413	3 413	3 413
		New	0	0	0	1 400	1 400	1 400	1 400	1 400
	HFO/LFO		2 229	2 045	1 580	284	284	0	0	0
	Hydro		21 756	23 094	25 994	28 225	30 339	32 293	33 626	34 695
	Wind		6 073	6 458	10 554	12 677	16 970	24 321	34 827	47 437
	Solar		5 033	5 404	10 908	18 121	23 932	30 398	36 325	43 928
	Other RES		270	611	1 677	2 510	3 185	3 868	4 882	5 477
Gross consumption, GWh			212 529	226 929	234 906	242 052	254 160	267 441	280 190	296 728
Net electricity generation, GWh	Total		211 602	222 115	234 336	224 064	234 330	250 886	271 983	294 705
	Coal and lignite		97 835	94 341	70 712	37 828	16 077	8 895	3 106	1 016
	Natural gas		17 125	27 683	36 713	27 311	34 709	26 959	17 914	5 410
	Nuclear		24 739	24 739	24 739	35 079	35 079	34 906	32 437	29 853
	HFO/LFO		2 132	2 105	1 684	0	0	0	0	0
	Hydro		50 157	51 507	59 548	66 279	72 790	78 662	83 744	87 687
	Wind		12 224	13 051	21 179	24 883	33 144	47 654	68 630	93 692
	Solar		6 091	6 410	13 367	22 293	29 040	36 459	42 995	51 506
	Other RES		1 299	2 280	6 394	10 392	13 490	17 350	23 157	25 542
Net import total, GWh			926	4 814	570	17 988	19 830	16 555	8 208	2 023
Net import ratio, %			0.4%	2.1%	0.2%	7.4%	7.8%	6.2%	2.9%	0.7%
RES-E share (RES-E production/gross consumption, %)			32.8%	32.3%	42.8%	51.2%	58.4%	67.4%	78.0%	87.1%
Utilisation rates of RES-E technical potential, %	Hydro		na	na	na	na	na	na	na	52.6%
	Wind		na	na	na	na	na	na	na	76.9%
	Solar		na	na	na	na	na	na	na	58.5%
Utilisation rates of conventional power production, %	Coal and lignite		46.2%	49.3%	50.4%	37.6%	23.2%	35.5%	18.0%	9.7%
	Natural gas		22.1%	34.5%	47.4%	39.3%	45.2%	45.2%	37.0%	22.3%
	Nuclear		82.7%	82.7%	82.7%	83.2%	83.2%	82.8%	76.9%	70.8%
Natural gas consumption of power generation, TWh			0	0	0	0	0	0	0	0
Security of supply	Generation adequacy margin		53%	45%	36%	28%	25%	14%	18%	16%
	System adequacy margin		191%	143%	211%	213%	209%	180%	174%	174%
CO_2 emission	Emission, Mt CO_2		123.0	121.6	96.5	53.4	30.3	19.3	9.7	3.0
	CO_2 emission reduction compared to 1990, %		27.7%	28.5%	43.3%	68.6%	82.2%	88.6%	94.3%	98.2%
Price impacts	Electricity wholesale price, €(2015)/MWh		34.7	42.4	52.7	59.5	66.5	79.5	82.3	72.2
	Total RES-E support/gross consumption, €(2015)/MWh, five year average		na	5.1	7.1	11.4	10.7	9.0	8.4	20.3
	Revenue from CO_2 auction/gross consumption, €(2015)/MWh		0	0	0	10.5	5.4	4.0	1.6	1.0
Investment cost, m€/5 year period	Coal and lignite		na	930.3	0	0	1 190.5	0	0	0
	Natural gas		na	1 306.1	0	0	0	0	0	0
	Total Fossil		na	2 236	0	0	1 191	0	0	0
	Total RES-E		na	2 600	17 526	17 236	19 223	20 362	26 031	31 176
	Total		na	4 837	17 526	17 236	20 413	20 362	26 031	31 176
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		na	na	na	na	na	na	na	na
	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 – NATIONAL RES TARGETS

			2016	2020	2025	2030	2035	2040	2045	2050
Installed capacity, MW	Coal, lignite	Existing	24 154	21 338	15 520	10 980	7 426	2 360	1 472	693
		New	0	500	500	500	500	500	500	500
	Natural gas	Existing	8 855	8 150	7 827	6 922	5 350	3 398	2 113	0
		New	0	1 007	1 007	1 007	2 607	2 607	2 607	1 974
	Nuclear	Existing	3 413	3 413	3 413	3 413	3 413	3 413	3 413	3 413
		New	0	0	0	1 400	1 400	1 400	1 400	1 400
	HFO/LFO		2 229	2 045	1 580	284	284	0	0	0
	Hydro		21 756	23 096	25 556	27 633	29 430	31 147	32 682	33 737
	Wind		6 073	6 468	10 487	14 497	18 718	27 009	36 615	46 030
	Solar		5 033	5 394	8 525	11 594	14 929	22 718	33 835	40 938
	Other RES		270	611	1 309	2 157	2 756	3 246	4 358	5 325
Gross consumption, GWh			212 529	224 721	229 755	233 829	242 336	251 560	260 693	272 938
Net electricity generation, GWh	Total		211 608	220 240	229 110	218 158	222 255	237 786	265 931	284 357
	Coal and lignite		97 834	94 082	70 672	38 429	16 957	9 071	2 905	629
	Natural gas		17 122	26 051	37 030	27 716	32 848	23 374	15 242	3 573
	Nuclear		24 739	24 739	24 739	35 079	35 079	34 933	33 371	31 417
	HFO/LFO		2 132	2 105	1 684	0	0	0	0	0
	Hydro		50 157	51 515	58 556	64 720	70 117	75 324	81 151	85 190
	Wind		12 234	13 069	21 178	29 379	37 912	54 348	73 428	91 325
	Solar		6 091	6 399	10 261	13 840	17 573	26 631	39 395	46 924
	Other RES		1 299	2 280	4 990	8 996	11 770	14 105	20 439	25 299
Net import total, GWh			921	4 481	645	15 671	20 080	13 774	-5 238	-11 419
Net import ratio, %			0.4%	2.0%	0.3%	6.7%	8.3%	5.5%	-2.0%	-4.2%
RES-E share (RES-E production/gross consumption, %)			32.8%	32.6%	41.3%	50.0%	56.7%	67.7%	82.2%	91.1%
Utilisation rates of RES-E technical potential, %	Hydro		na	na	na	na	na	na	na	51.0%
	Wind		na	na	na	na	na	na	na	74.3%
	Solar		na	na	na	na	na	na	na	54.6%
Utilisation rates of conventional power production, %	Coal and lignite		46.2%	49.2%	50.4%	38.2%	24.4%	36.2%	16.8%	6.0%
	Natural gas		22.1%	32.5%	47.9%	39.9%	47.1%	44.4%	36.9%	20.7%
	Nuclear		82.7%	82.7%	82.7%	83.2%	83.2%	82.9%	79.1%	74.5%
Natural gas consumption of power generation, TWh			0	0	0	0	0	0	0	0
Security of supply	Generation adequacy margin		53%	46%	36%	30%	26%	15%	20%	20%
	System adequacy margin		191%	145%	215%	218%	205%	180%	181%	184%
CO_2 emission	Emission, Mt CO_2		123.0	120.8	96.6	54.2	30.7	18.2	8.6	2.0
	CO_2 emission reduction compared to 1990, %		27.7%	29.0%	43.3%	68.2%	82.0%	89.3%	95.0%	98.8%
Price impacts	Electricity wholesale price, €(2015)/MWh		34.7	42.1	52.5	59.4	66.7	80.4	84.1	71.6
	Total RES-E support/gross consumption, €(2015)/MWh, five year average		na	5.1	4.5	10.7	8.3	6.4	5.4	17.3
	Revenue from CO_2 auction/gross consumption, €(2015)/MWh		0	0	0	11.1	6.0	4.3	1.6	0.7
Investment cost, m€/5 year period	Coal and lignite		na	1 306.1	0	0	0	0	0	0
	Natural gas		na	930.3	0	0	732.5	0	0	0
	Total Fossil		na	2 236	0	0	732	0	0	0
	Total RES-E		na	2 606	13 189	15 722	16 205	21 820	28 981	28 245
	Total		na	4 843	13 189	15 722	16 938	21 820	28 981	28 245
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		na	na	na	na	na	na	na	na
	CO_2 price, €(2015)/t		8.60	15.00	22.50	33.50	42.00	50.00	69.00	88.00

TABLE A8 | SENSITIVITY ANALYSIS – LOW RENEWABLE POTENTIAL

			2016	2020	2025	2030	2035	2040	2045	2050
Installed capacity, MW	Coal, lignite	Existing	24 154	21 338	15 520	10 980	7 426	2 360	1 472	693
		New	0	500	500	500	500	500	500	500
	Natural gas	Existing	8 855	8 150	7 827	6 922	5 350	3 398	2 113	0
		New	0	1 007	1 007	1 007	3 307	3 307	3 307	2 674
	Nuclear	Existing	3 413	3 413	3 413	3 413	3 413	3 413	3 413	3 413
		New	0	0	0	1 400	1 400	1 400	1 400	1 400
	HFO/LFO		2 229	2 045	1 580	284	284	0	0	0
	Hydro		21 756	23 055	25 703	27 421	29 189	30 403	31 205	31 737
	Wind		6 073	6 135	9 317	9 763	10 889	15 563	23 516	28 756
	Solar		5 033	5 494	11 615	19 247	27 351	36 945	46 683	56 903
	Other RES		270	587	1 601	2 260	2 928	3 420	4 206	5 813
Gross consumption, GWh			212 528	224 715	229 747	233 806	242 931	251 829	261 224	272 613
Net electricity generation, GWh	Total		211 570	219 792	230 269	217 531	222 749	234 707	252 299	263 086
	Coal and lignite		97 847	94 152	70 670	39 336	17 086	9 649	3 520	923
	Natural gas		17 138	26 417	35 335	27 184	35 368	28 597	19 651	5 165
	Nuclear		24 739	24 739	24 739	35 079	35 079	35 074	33 422	31 497
	HFO/LFO		2 132	2 105	1 684	0	0	0	0	0
	Hydro		50 157	51 361	58 873	64 112	69 500	72 952	76 023	77 818
	Wind		12 171	12 330	18 605	19 108	20 937	30 138	46 117	56 216
	Solar		6 106	6 500	14 238	23 615	32 638	43 896	55 187	66 284
	Other RES		1 279	2 187	6 126	9 098	12 140	14 401	18 379	25 183
Net import total, GWh			959	4 923	-521	16 275	20 183	17 122	8 925	9 527
Net import ratio, %			0.5%	2.2%	-0.2%	7.0%	8.3%	6.8%	3.4%	3.5%
RES-E share (RES-E production/gross consumption, %)			32.8%	32.2%	42.6%	49.6%	55.7%	64.1%	74.9%	82.7%
Utilisation rates of RES-E technical potential, %	Hydro		na	na	na	na	na	na	na	47.6%
	Wind		na	na	na	na	na	na	na	46.4%
	Solar		na	na	na	na	na	na	na	75.7%
Utilisation rates of conventional power production, %	Coal and lignite		46.2%	49.2%	50.4%	39.1%	24.6%	38.5%	20.4%	8.8%
	Natural gas		22.1%	32.9%	45.7%	39.1%	46.6%	48.7%	41.4%	22.1%
	Nuclear		82.7%	82.7%	82.7%	83.2%	83.2%	83.2%	79.3%	74.7%
Natural gas consumption of power generation, TWh			0	0	0	0	0	0	0	0
Security of supply	Generation adequacy margin		53%	46%	37%	27%	23%	11%	13%	11%
	System adequacy margin		191%	145%	211%	211%	200%	173%	162%	151%
CO_2 emission	Emission, Mt CO_2		123.0	121.0	95.9	55.1	31.7	20.7	10.7	2.8
	CO_2 emission reduction compared to 1990, %		27.7%	28.9%	43.6%	67.6%	81.4%	87.8%	93.7%	98.3%
Price impacts	Electricity wholesale price, €(2015)/MWh		34.7	42.2	52.5	59.6	66.8	81.7	85.6	74.5
	Total RES-E support/gross consumption, €(2015)/MWh, five year average		na	4.9	6.9	9.2	8.4	7.7	10.0	78.0
	Revenue from CO_2 auction/gross consumption, €(2015)/MWh		0	0	0	11.4	6.1	4.6	2.0	1.0
Investment cost, m€/5 year period	Coal and lignite		na	930.3	0	0	732.5	0	0	0
	Natural gas		na	0	0	0	0	0	0	0
	Total Fossil		na	930	0	0	732	0	0	0
	Total RES-E		na	2 124	16 731	14 061	17 046	17 815	23 607	24 067
	Total		na	3 054	16 731	14 061	17 778	17 815	23 607	24 067
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		na	na	na	na	na	na	na	na
	CO_2 price, €(2015)/t		8.60	15.00	22.50	33.50	42.00	50.00	69.00	88.00

TABLE A9 | STRANDED COSTS, TOTAL (m€) AND IN CAPACITY FEE EQUIVALENT (€/MWh)

Scenario	Country	Total stranded cost (m€)	Capacity fee for 10 years (€/MWh)
NO TARGET	AL	-102	-0.8
	BA FED	-878	-6.3
	BA SRP	-634	-9.5
	BG	-984	-2.5
	GR	-2 089	-3.9
	KO*	-629	-7.8
	ME	-133	-2.7
	MK	-287	-2.9
	RO	-117	-0.2
	RS	-1 033	-2.2
	SEERMAP	-6 886	-2.6
DELAYED	AL	-97	-0.8
	BA FED	-912	-6.5
	BA SRP	-653	-9.8
	BG	-872	-2.2
	GR	-1 932	-3.6
	KO*	-664	-8.2
	ME	-140	-2.8
	MK	-287	-2.9
	RO	12	0
	RS	-1 056	-2.3
	SEERMAP	-6 600	-2.5
DECARBONISATION	AL	-7	-0.1
	BA FED	0	0
	BA SRP	0	0
	BG	-874	-2.3
	GR	-739	-1.4
	KO*	-9	-0.1
	ME	0	0
	MK	0	0
	RO	-14	0
	RS	-7	0
	SEERMAP	-1 650	-0.6

TABLE A10 | BREAKDOWN OF CUMULATIVE CAPITAL EXPENDITURE BY RES TECHNOLOGY 2016-2050 (m€)

Capital expenditures in m€	No target 2016-2050	Delayed 2016-2050	Decarbonisation 2016-2050
Biogas	1 220	1 649	5 174
Solid biomass	1 733	2 054	9 855
Biowaste	1 379	1 411	1 221
Geothermal ele.	1 409	2 486	1 970
Hydro large-scale	7 712	11 487	12 243
Hydro small-scale	3 980	5 665	6 781
Central PV	5 060	10 631	14 237
Decentralised PV	10 129	18 821	21 653
CSP	–	52	–
Wind onshore	24 629	54 041	50 979
Wind offshore	499	906	940
RES-E total	**57 749**	**109 204**	**125 053**
of which CHP	3 629	3 968	8 690

TABLE A11 | 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	**11 041**	**7 013**	**5 156**	**1 571**	**585**	**384**	**119**	**25 868**
Central PV	3 584	2 084	1 650	435	149	66	–	7 968
Decentralised PV	4 271	2 804	2 383	610	126	57	–	10 251
Wind onshore	1 859	1 237	555	216	54	–	–	3 921
Delayed	**11 070**	**8 034**	**4 998**	**2 237**	**3 492**	**5 433**	**34 482**	**69 746**
Central PV	3 589	2 053	1 538	431	318	582	3 743	12 253
Decentralised PV	4 274	2 915	2 311	662	494	826	4 785	16 268
Wind onshore	1 868	1 519	530	525	1 468	2 394	16 163	24 468
Decarbonisation	**11 041**	**7 597**	**8 215**	**5 765**	**3 945**	**2 140**	**2 883**	**41 586**
Central PV	3 584	2 100	2 252	1 625	1 604	1 206	1 613	13 985
Decentralised PV	4 271	3 035	3 077	1 738	958	291	639	14 008
Wind onshore	1 858	1 872	2 358	1 967	972	100	368	9 496

TABLE A12 | NTC VALUE CHANGES IN 2030 AND 2050 IN THE 'DELAYED' AND 'DECARBONISATION' SCENARIOS COMPARED TO THE BASE CASE

	Delayed Scenario				Decarbonisation Scenario			
	2030 winter	2030 summer	2050 winter	2050 summer	2030 winter	2030 summer	2050 winter	2050 summer
RS – RO	0	0	300	250	-300	-50	-50	150
RO – RS	150	150	500	450	-150	50	100	300
BG – RS	200	250	500	550	550	600	1 000	1 050
RS – BG	350	400	450	450	650	700	800	800
KO* – MK	100	100	0	0	100	100	0	0
MK – KO*	100	100	0	0	100	100	0	0
RS – MK	-250	-200	-50	-50	-550	-400	-450	-300
MK – RS	-700	-700	0	0	-750	-700	-200	0
KO* – AL	150	140	700	700	150	140	700	700
AL – KO*	150	140	200	500	150	140	200	500
RS – AL	0	0	0	0	0	0	0	0
Al – RS	0	0	0	0	0	0	0	0
RS – KO*	0	0	0	0	0	0	0	0
KO* – RS	0	0	0	0	0	0	0	0
KO* – ME	0	0	0	0	0	0	0	0
ME – KO*	0	0	0	0	0	0	0	0
RS – ME	-50	300	0	250	-350	-250	-350	-350
ME – RS	200	250	150	200	-150	-100	-250	-200
RS – BA	0	550	0	500	-550	-250	-550	-300
BA – RS	-100	400	0	500	-200	200	-100	250
BA – ME	550	800	150	300	250	400	-150	-100
ME – BA	1 350	1 100	450	350	850	700	-50	-50
AL – ME	0	0	0	0	0	50	0	50
ME – AL	0	0	0	0	200	200	250	250
AL – GR	-100	-100	0	0	-250	-250	-200	-200
GR – AL	-50	-50	0	0	-100	-100	-50	-50
AL – MK	200	200	0	0	300	300	150	400
MK – AL	400	400	0	0	450	450	50	50
MK – GR	250	400	0	0	-50	-50	-350	-450
GR – MK	300	500	0	0	250	400	-50	-100
BG – MK	70	100	0	0	-80	0	-200	-100
MK – BG	250	300	0	0	200	200	-50	-100
RO – BG	750	1 150	0	500	1 250	1 400	500	700
BG – RO	1 150	1 650	0	550	1 750	2 000	600	900
BG – GR	-878	-750	0	0	-1 128	-1 000	-550	-550
GR – BG	-32	0	0	0	-332	-350	-250	-350

Annex 2 | Assumptions

Assumed technology investment cost trajectories: RES and fossil

TABLE A13 | ASSUMED SPECIFIC COST TRAJECTORIES FOR THE VARIOUS TECHNOLOGIES (2016 €/kW)

Technology	CCS	2020	2030	2040	2050
Thermal	no	2 586	2 460	2 339	2 225
	yes	5 472	4 705	4 045	3 477
OCGT	no	879	877	876	874
	yes	1 688	1 496	1 326	1 175
CCGT	no	922	918	913	909
	yes	1 747	1 502	1 291	1 110
Biogas (low cost options: landfill and sewage gas)	no	1 608	1 504	1 406	1 315
Biogas (high cost options: agricultural digestion in small-scale CHP plants)	no	5 378	4 956	4 568	4 210
Solid biomass (low cost options: cofiring)	no	597	553	513	476
Solid biomass (medium cost options: large-scale CHP)	no	2 410	2 230	2 064	1 910
Solid biomass (high cost options: small/medium-scale CHP)	no	3 912	3 621	3 351	3 101
Biowaste	no	6 573	6 070	5 606	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))	–	3 273	2 963	3 269	3 167
Hydro large-scale	–	1 333	1 396	1 667	1 765
Hydro small-scale	–	1 338	1 763	1 956	1 994
Photovoltaics	–	1 015	824	693	596
Wind onshore	–	1 395	1 271	1 199	1 125
Wind offshore	–	2 693	2 521	2 293	2 346

Source: Green-X database and EEMM database

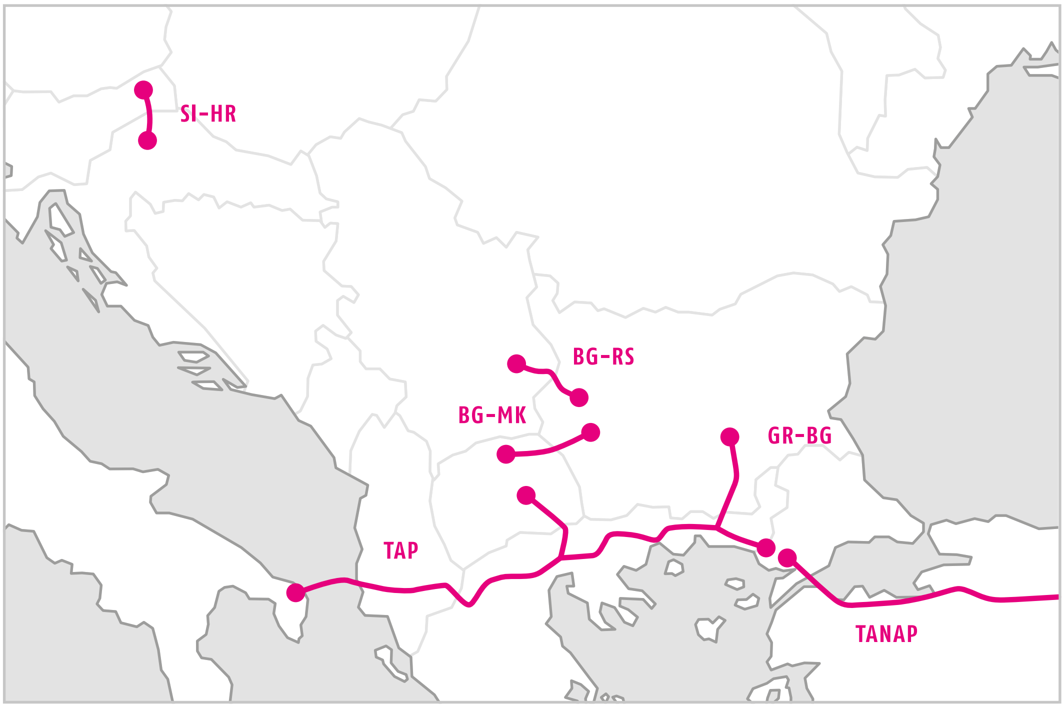
Infrastructure

TABLE A14 | NEW GAS INFRASTRUCTURE

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 A15 | NEW 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

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