SOUTH EAST EUROPE ELECTRICITY ROADMAP

Country report

Montenegro

SEERMAP: South East Europe Electricity Roadmap
Country report: Montenegro 2017

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

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

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

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

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

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

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

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

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

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

Local partners in SEERMAP target countries

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.

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

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

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

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

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

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

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

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

Montenegro currently has a mix of lignite and hydro capacity. The total lignite capacity currently installed, 219 MW, will need to be decommissioned by 2023 according to national plans, in line with Energy Community Acquis commitments. Several options are available to ensure that electricity demand is met in future.

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

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

The modelling work carried out under the SEERMAP project identifies the following key findings with respect to the different electricity strategy approaches that Montenegro can take:

- Irrespective of the investment portfolio implemented or whether RES support policies are in place, Montenegro will only generate none or a very small percentage of its electricity from lignite by 2050 according to the modelling results. Assuming a competitive electricity market, due to strong interconnections between Montenegro and its neighbours, the power plants in Montenegro compete with other power plants in the region and the EU. The wholesale price and carbon and fuel prices have a major influence on which power plants come online at any given moment to satisfy demand. In scenarios where a lignite based new power plant is built according to national plans, the new lignite based power plant. It is idle for most of the year by 2050 due to high carbon costs. National policy makers therefore have little scope to influence the electricity mix over the long term through investment decisions.

- Despite the large share of RES-based production even in the 'no target' scenario, current policies and trends fall slightly short of the deep electricity sector target reflected in the EU Roadmap 2050 of 93-99% emission reduction by 2050. Without a target or if action is delayed, Montenegro would decrease its carbon emissions by around 90%.
- Delayed action on renewables is feasible, but has two disadvantages compared with a long term planned effort to support renewable generation. Delayed or no action results in stranded fossil based power generation assets, including currently planned power plants. Translated into a price increase over a 10 year period, the cost of stranded assets is estimated at 2.7-2.8 EUR/MWh in the 'no target' and 'delayed' scenarios. In addition, assuming delayed action, the disproportionate effort required towards the end of the modelled period to enable the CO_2 emission target to be met implies a significant increase in RES support.
- In all scenarios, Montenegro produces significantly more electricity than it consumes throughout the modelling period; its generation and system adequacy indicators remain favourable as well.
- Decarbonisation of the electricity sector does not drive wholesale electricity prices up compared to a scenario where no emission reduction target is set. The price of electricity follows a similar trajectory under all scenarios and only diverges after 2045. After this year, prices are lower in scenarios with high levels of RES in the electricity mix, as a result of the low marginal cost of RES electricity production.
- Under all scenarios there is a significant increase in the wholesale electricity price compared with current (albeit historically low) price levels. This increase is characteristic of the entire SEERMAP region, and in fact the EU as a whole, in all scenarios for the modelled time period. The increase is driven by the price of carbon and the price of natural gas, both of which increase significantly by 2050. The share of electricity expenditure as a share of household income increases over time in all scenarios, and is particularly high over the long term in the 'delayed' scenario, where this value doubles compared with current levels by 2050. The increase is lowest over the long term in the 'decarbonisation' scenario. A positive implication of the wholesale price increase is that it makes investment in electricity generation more attractive to investors, addressing the current under-investment in the sector.
- Decarbonisation will require an approximately 40% increase in total investment in generation capacity over the entire modelled period compared with the 'no target' scenario. 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 social point of view, the high level of investment has a positive impact on GDP and a small negative impact on employment.
- Network investment needs are 30 mEUR beyond plans included in ENTSO-E TYNDP (2016). The necessary network investment is significantly lower than the investment needed in generation assets.

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

- The high penetration of RES in all scenarios suggests a policy focus on enabling RES integration; this involves investing in transmission and distribution networks, enabling demand side management and RES production through a combination of technical solutions and appropriate regulatory practices, and promoting investment in storage solutions including hydro and small scale storage.

- RES potential can be reaped through policies eliminating barriers to RES investment. De-risking policies addressing high financing cost and high cost of capital are especially relevant in the region and in Montenegro as well, as it would allow for cost-efficient renewable energy investments.
- Co-benefits of investing in renewable electricity generation can strengthen the case for increased RES investment. Co-benefits, not assessed here, include health and environmental benefits from reduced emissions of air pollutants.
- Policy makers need to address the trade-offs which characterise fossil fuel investments. Montenegro's new lignite capacity that is currently planned to replace existing capacity, to be decommissioned by 2023, is expected to be priced out of the market before the end of its lifetime due to a carbon price which was assumed to apply to Montenegro from 2030 onwards; this will result in stranded costs. These costs need to be weighed against any short term benefits that such investments may provide.
- Measures to address affordability may need to be considered over the long term. The practice of subsidising fossil fuel based electricity generation cannot be maintained over the long term due to EU rules on state aid, and other types of policy instruments will need to be considered.
- Regional level planning improves system adequacy compared with plans which emphasise reliance on national production capacities.

2 | Introduction

2.1 Policy context

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

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

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

2.2 The SEERMAP project at a glance

The South East Europe Electricity Roadmap (SEERMAP) project develops electricity sector scenarios until 2050 for the South East Europe region. Geographically the SEERMAP project focuses on 9 countries in South East Europe: Albania, Bosnia and Herzegovina, Kosovo* (in line with UNSCR 1244 and the ICJ Opinion on the Kosovo declaration of independence), former Yugoslav Republic of Macedonia (Macedonia), Montenegro and Serbia (WB6) and Bulgaria, Greece and Romania (EU3). The SEERMAP region consists of EU member states, as well as candidate and potential candidate countries. For non-member states some elements of EU energy policy are translated into obligations via the Energy Community Treaty, while member states must transpose and implement the full spectrum of commitments under the EU climate and energy acquis.

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

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

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

2.3 Scope of this report

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

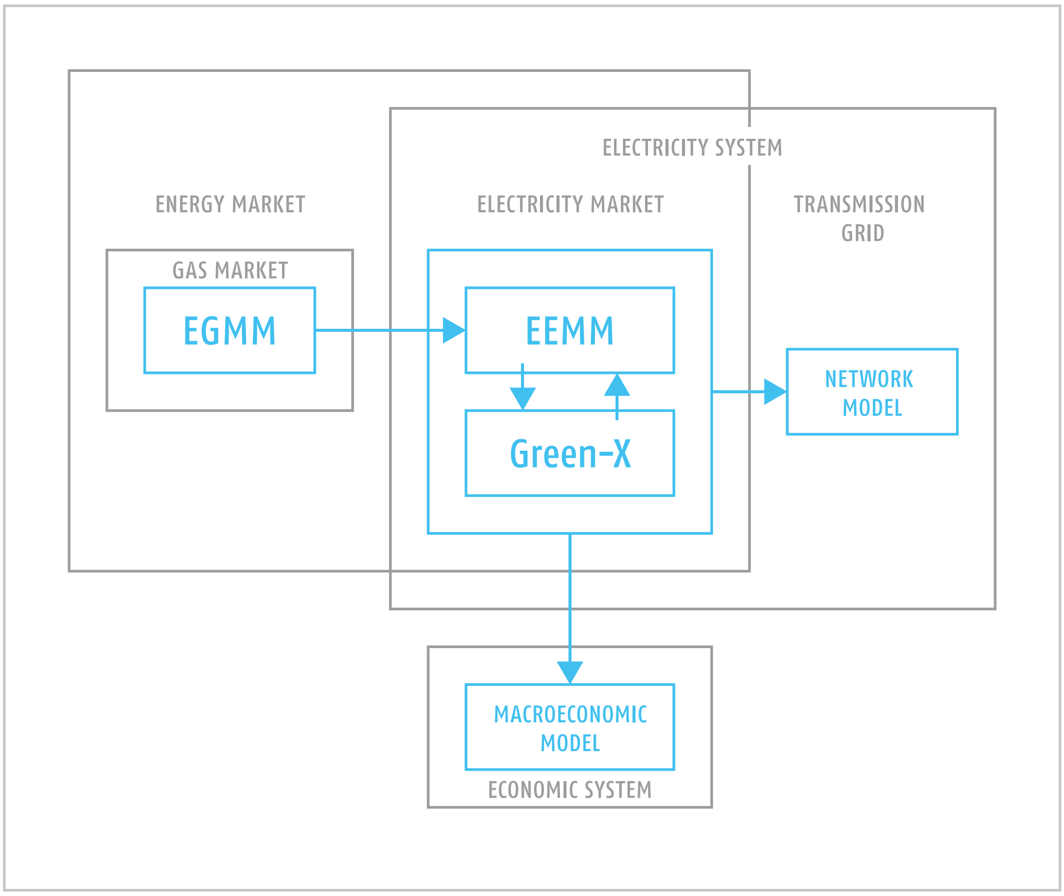
3 | Methodology

Electricity sector futures are explored using a set of five high resolution models incorporating the crucial factors which influence electricity policy and investment decisions. The European Electricity Market Model (EEMM) and the Green-X model together assess the impact of different scenario assumptions on power generation investment and dispatch decisions. The EEMM is a partial equilibrium microeconomic model. It assumes that the electricity market is fully liberalised and perfectly competitive. In the model, electricity generation as well as cross border capacities are allocated on a market basis without gaming or withholding capacity: the cheapest available generation will be used, and if imports are cheaper than producing electricity domestically demand will be satisfied with imports. Both production and trade are constrained by the available installed capacity and net transfer capacity (NTC) of cross border transmission networks respectively. Due to these capacity constraints, prices across borders are not always equalised. Investment in new generation capacity is either exogenous in the model (based on official policy documents), or endogenous. Endogenous investment is market-driven; power plant operators anticipate costs over the upcoming 10 years and make investment decisions based exclusively on profitability. If framework conditions (e.g. fuel prices, carbon price, available generation capacities) change beyond this timeframe then the utilisation of these capacities may change and profitability is not guaranteed.

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

The EEMM model has an hourly time step, modelling 90 representative hours with respect to load, covering all four seasons and all daily variations in electricity demand. The selection of these hours ensures that both peak and base load hours are represented,

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")



and that the impact of volatility in the generation of intermittent RES technologies on wholesale price levels is captured by the model. The model is conservative with respect to technological developments and thus no significant technological breakthrough is assumed (e.g. battery storage, fusion, etc.).

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

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

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

- the European Gas Market Model (EGMM) to provide gas prices for each country up to 2050 used as inputs for EEMM;

- the network model is used to assess whether and how the transmission grid needs to be developed due to generation capacity investments, including higher RES penetration;
- macroeconomic models for each country are used to assess the impact of the different scenarios on macroeconomic indicators such as GDP, employment, and the fiscal and external balances.

4 | Scenario descriptions and main assumptions

4.1 Scenarios

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

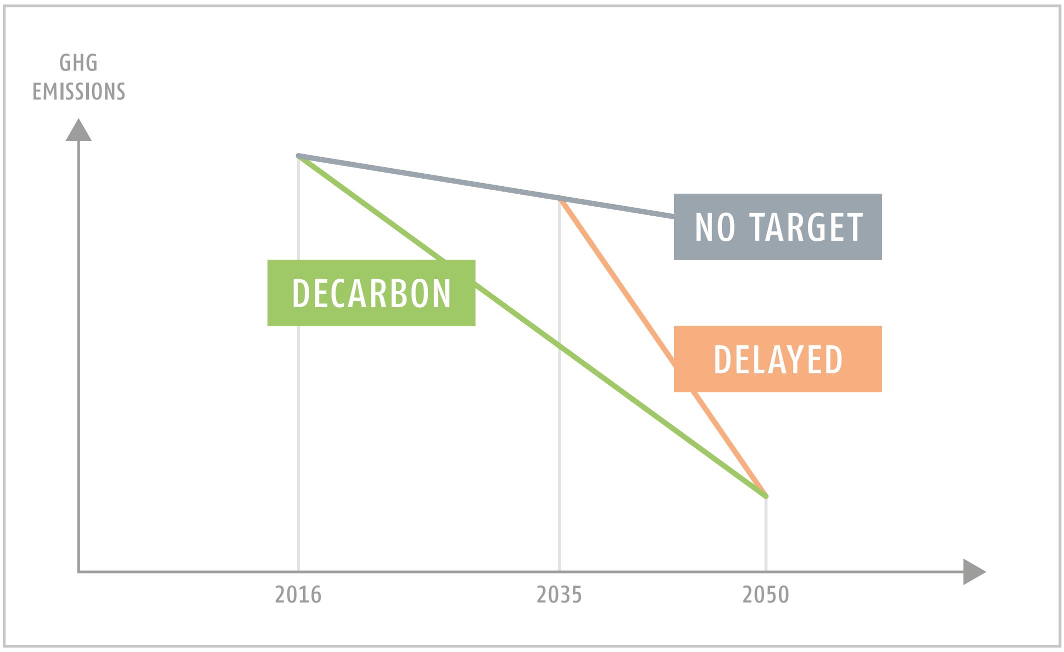
The modelling work does not take into account the impacts of the new Large Combustion Plant BREF (Commission Implementing Decision of 2017/1442), as it entered into force in July 2017.

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 reductions will be higher in some countries and lower in others, depending on where emissions can be reduced most cost-efficiently.

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

- In the 'no target' scenario all currently planned fossil fuel power plants are entered into the model exogenously. Information on planned power plants is taken from official national

FIGURE 2
THE CORE SCENARIOS



strategies/plans and information received from the local partners involved in the project. We have assumed the continuation of current renewable support policies up to 2020 and the gradual phasing out of support between 2021 and 2025. The scenario assumes countries meet their 2020 renewable target but do not set a CO_2 emission reduction target for 2050. Although a CO_2 target is not imposed, producers face CO_2 prices in this scenario, as well as in the others.

- In the 'decarbonisation' scenario, only those planned investments which had a final investment decision in 2016 were considered, resulting in lower exogenous fossil fuel capacity. With a 94% CO_2 reduction target, RES support in the model was calculated endogenously to enable countries to reach their decarbonisation target by 2050 with the necessary renewable investment. RES targets are not fulfilled nationally in the model, but are set at a regional level, with separate targets for the SEERMAP region and for the rest of the EU.
- The 'delayed' scenario considers that currently planned power plants are built according to national plans, similarly to the 'no target' scenario. It assumes the continuation of current RES support policies up to 2020 with a slight increase until 2035. This RES support is higher than in the 'no target' scenario, but lower than the 'decarbonisation' scenario. Support is increased from 2035 to reach the same CO_2 emission reduction target as the 'decarbonisation' scenario by 2050.

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

4.2 Main assumptions

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

Demand:

- Projected electricity demand is based – to the extent possible – on data from official national strategies. Where official projections do not exist for the entire period until 2050, electricity demand growth rates were extrapolated based on the EU Reference scenario for 2013 or 2016 (for non-MS and MS respectively). The PRIMES EU Reference scenarios assume low levels of energy efficiency and low levels of electrification of transport and space heating compared with a decarbonisation scenario. The average annual electricity growth rate for the SEERMAP region as a whole is 0.74% over the period 2015 and 2050. The annual demand growth rate for countries within the region is varies significantly, with the value for Greece as low as 0.2%, and for Bosnia and Herzegovina as high as 1.7%. Whereas the growth rate in all EU3 countries is below 0.7%, Macedonia is the only country in the WB6 where the growth rate is below 1% a year. For Montenegro, demand figures for 2015 and 2016 were provided by our local partner, and PRIMES projections were used up to 2050. These figures indicate an average annual growth rate in electricity demand of 1.3% between 2015 and 2050.
- 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 coal is expected to increase by approximately 15% between 2016 and 2050; in the same period gas prices increase by around 76% and oil prices by around 250%, because of historically low prices in 2016. Compared to 2012-2013 levels, this would mean an only 15-20% increase by 2050.
- Cost of different technologies: Information on the investment cost of new generation technologies is taken from EIA (2017).
- Weighted average cost of capital (WACC): The WACC has a significant impact on the cost of investment, with a higher WACC implying a lower net present value and therefore a more limited scope for profitable investment. The WACCs used in the modelling are country-specific, these values are modified by technology-specific and policy instrument-specific risk factors. The country-specific WACC values in the region are assumed to be between 10 and 15% in 2016, decreasing to between 9.6 and 11.2% by 2050. The value is highest for Greece in 2016, and remains one of the highest by 2050. In contrast, the WACC values for the other two EU member states, Romania and Bulgaria, are on the lower end of the spectrum, as are the values for Kosovo* and Macedonia. The country-specific WACC for Montenegro was assumed to be 12% in 2015, decreasing to 11.2% by 2050.
- Carbon price: a price for carbon is applied for the entire modelling period for EU member states and from 2030 onwards in non-member states, under the assumption that all candidate and potential candidate countries will implement the EU Emissions Trading Scheme or a corresponding scheme by 2030. The carbon price is assumed to increase from 33.5 EUR/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 Transadriatic (TAP) and Transanatolian (TANAP) gas pipelines (see Annex 2) are built between 2016 and 2021, and the expansion of the Revithoussa and the establishment of the Krk LNG terminals are taken into account. No further gas transmission infrastructure development was assumed in the period to 2050.

Renewable energy sources and technologies:

- Long-term technical RES potential is estimated based on several factors including the efficiency of conversion technologies and GIS-based data on wind speed and solar irradiation, and is reduced by land use and power system constraints. It is also assumed that the long term potential can only be achieved gradually, with renewable capacity increase restricted over the short term. A sensitivity analysis measured the reduced potential of the most contentious RES capacities, wind and hydro. The results of the sensitivity analysis are discussed in section 5.5.
- Capacity factors of RES technologies were based on historical data over the last 5 to 8 years depending on the technology.

Annex 2 contains detailed information on the assumptions.

5 | Results

5.1 Main electricity system trends

Montenegro is already in an advantageous position in terms of RES-generation due to a large share of hydro capacities, which accounted for 75% of total installed capacity in 2016. The total lignite capacity currently installed, 219 MW, will need to be decommissioned by 2023 according to national plans, in line with Energy Community Acquis commitments. Several options are available to ensure that electricity demand is met in future.

Lignite becomes insignificant as a source of electricity generation in all scenarios by 2050. Despite investment in new lignite capacity in the ‘no target’ and ‘delayed’ scenarios

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

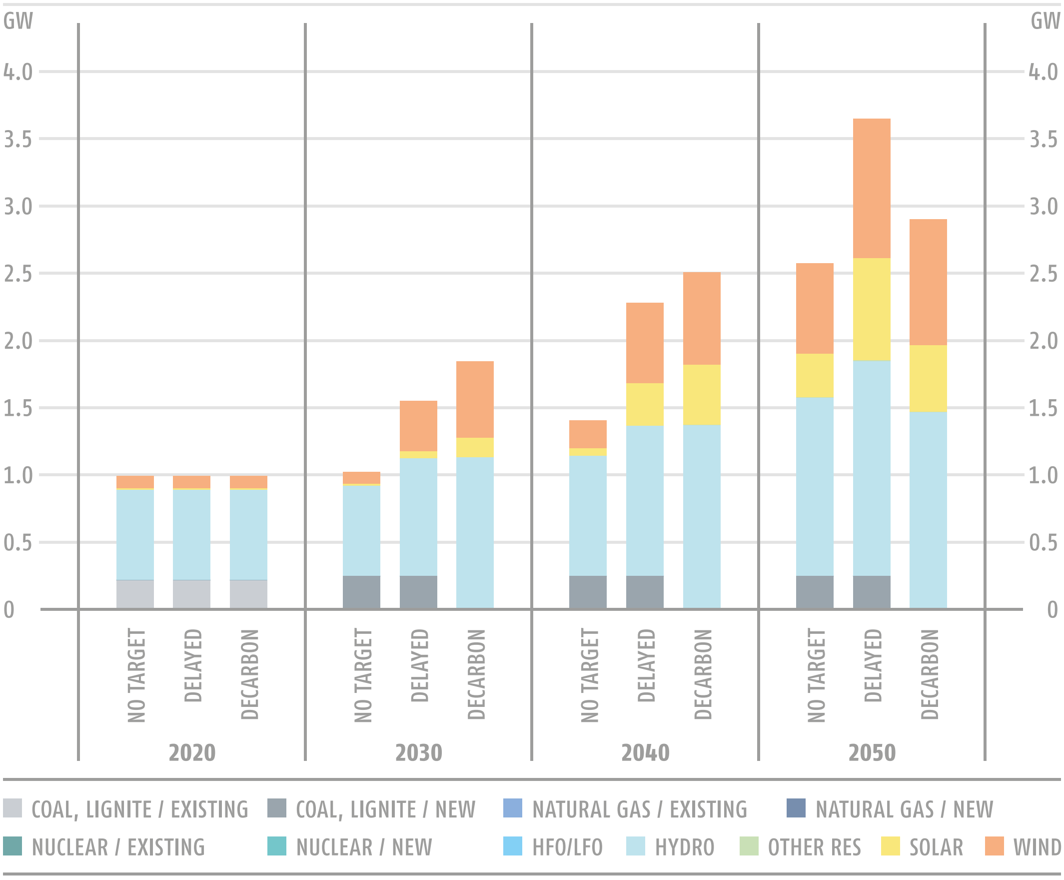


FIGURE 4
ELECTRICITY GENERATION AND DEMAND (TWh) AND RES SHARE (% OF DEMAND) IN MONTENEGRO, 2020-2050

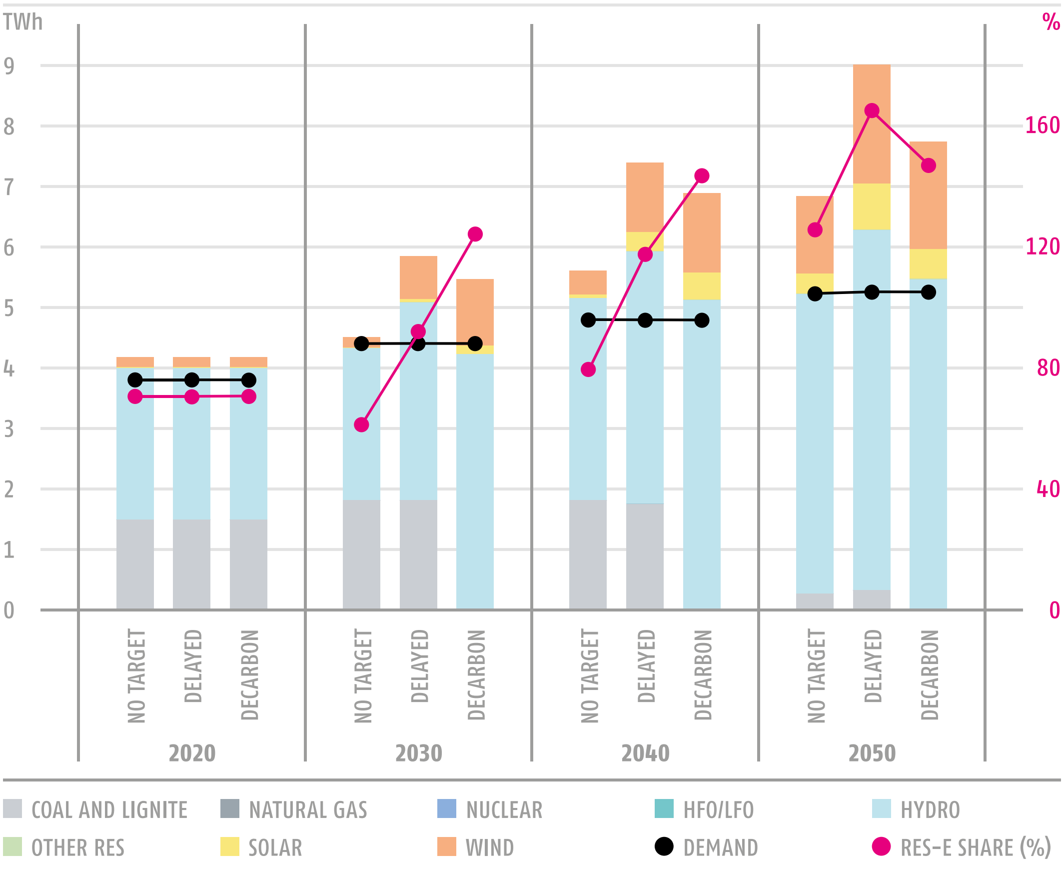
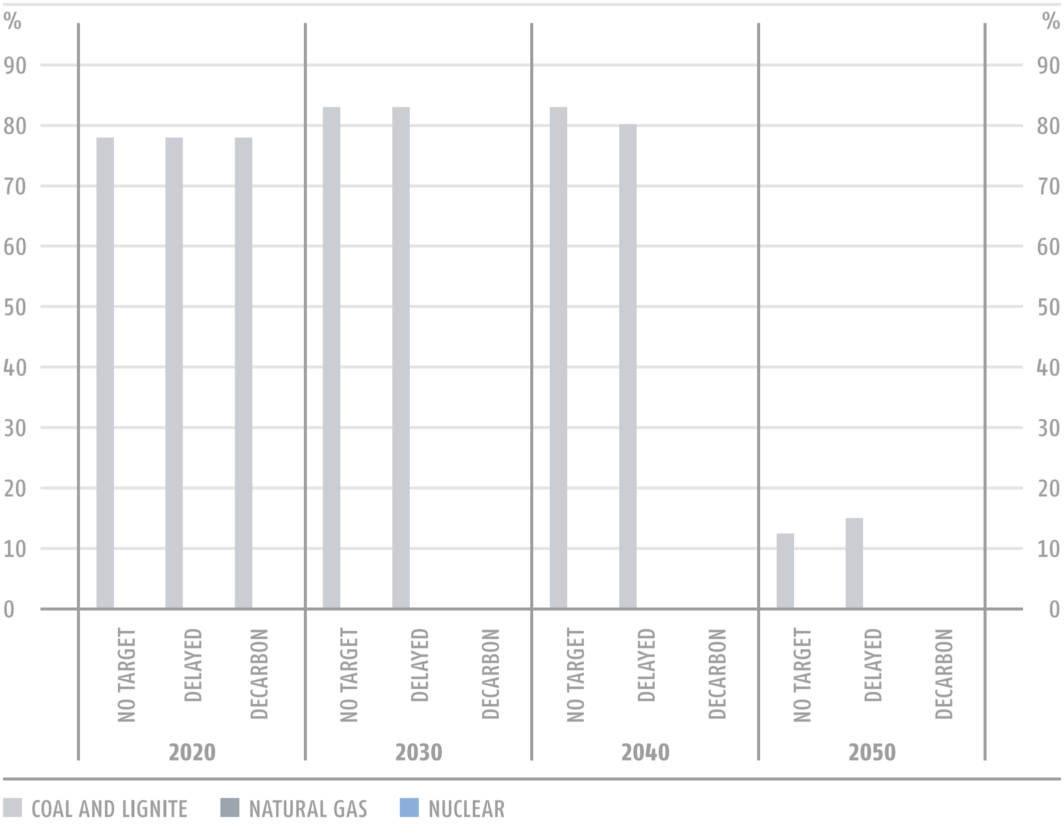


FIGURE 5
UTILISATION RATES OF CONVENTIONAL GENERATION IN MONTENEGRO, 2020-2050 (%)



according to national plans, the contribution of lignite to electricity generation is by 2050 is less than 4% in both scenarios. This is driven mainly by the high carbon price, as well as the increase in competitiveness of renewable technologies over time.

These figures suggest that Montenegro has very good potential for RES-based generation, giving it some flexibility to increase its contribution to meeting regional targets. In the 'decarbonisation' and 'delayed' scenarios, RES-based production reaches 147% and 165% of consumption in 2050, respectively.

Even though wind and solar capacities are expected to grow much faster than hydro, hydro maintains its role as the prominent source of power generation. Its current share of 62% of total generation increases to above 70% in both the 'decarbonisation' and the 'no target' scenarios by 2050. In the 'decarbonisation' scenario the share of wind power rises to 23% by 2050 from only 4% in 2020, but it reaches 19% even under the 'no target' scenario. In line with the sharp increase of solar capacities between 2040 and 2050 in the 'delayed' scenario, the share of solar power in 2050 is highest in this scenario with 8% of production, as opposed to 5-6% in the other scenarios.

In all scenarios, Montenegro is expected to significantly increase its net electricity exports. Domestic demand is projected to be only 52-53% higher in 2050 than in 2016, whereas production may rise by 170-225% between 2016 and 2050, depending on the scenario.

The importance of Montenegro's lignite power plant will fade by 2050 due to low utilization rates of lignite capacity in the 'no target' and 'delayed' scenarios. In 2016, 219 MW of lignite capacity generated almost 1.5 TWh of electricity, whereas in 2050, only around 0.3 TWh seems realistic with a generation fleet of similar size in the 'no target' and 'delayed' scenarios. This means a sharp drop of utilisation rates for the newly built lignite plant, which will be deployed between 2020 and 2030 in these two scenarios. In 2040, it is still projected to operate at a healthy utilisation rate of 80-83%, which then falls to 13-15%, raising questions about the recovery of the investment. The decrease in lignite based electricity generation is driven mainly by two factors: an increasing carbon price which is assumed to be applied in Montenegro from 2030 onwards, and by the increased competitiveness of renewable electricity generation resulting from decreasing technology costs and increasing electricity prices.

5.2 Security of supply

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

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

For Montenegro, the generation adequacy margin is positive throughout the modelling period, i.e. domestic generation capacity is sufficient to satisfy domestic demand in all hours of the year for all of the years shown. The system adequacy margin is even higher.

In addition to the adequacy margin indicators, the cost of increasing the generation adequacy margin to zero was calculated, if the generation adequacy indicator was negative to begin with. The cost of the necessary capacity was defined as the yearly fixed cost of an open cycle gas turbine (OCGT) which has adequate capacity to ensure that the generation adequacy margin reaches zero. As the generation adequacy margin for Montenegro was positive at the outset for all years under all scenarios, this cost for Montenegro is zero.

5.3 Sustainability

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

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

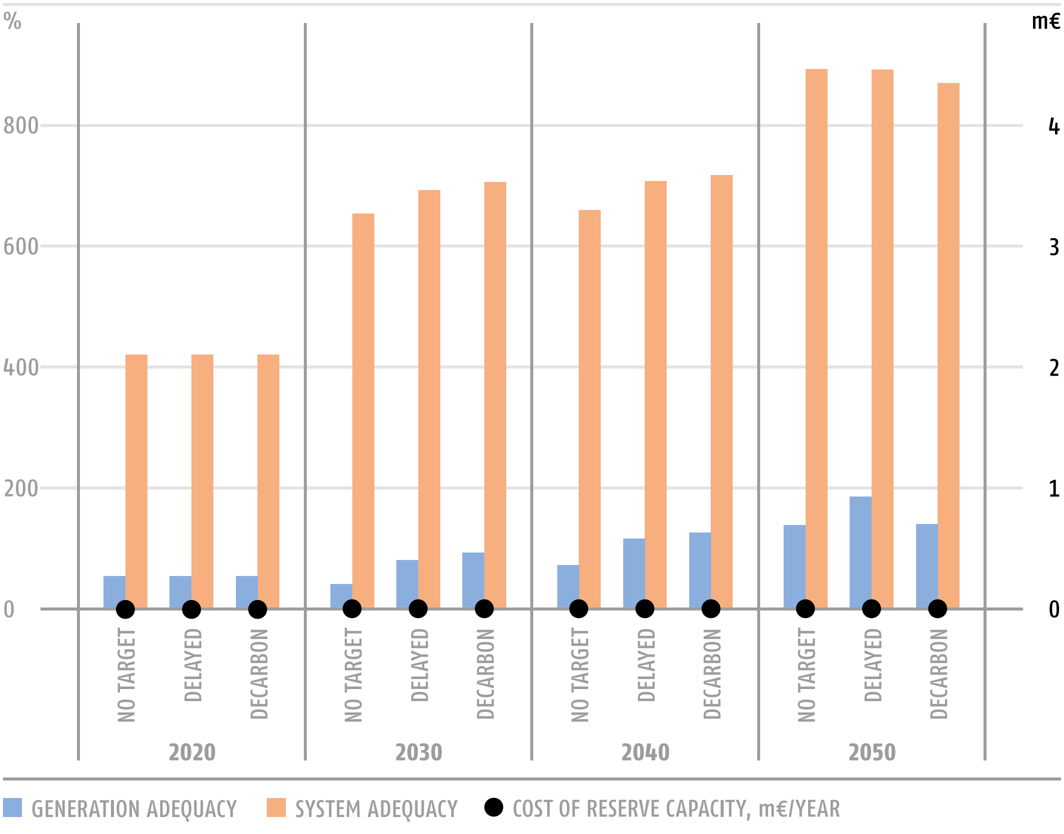
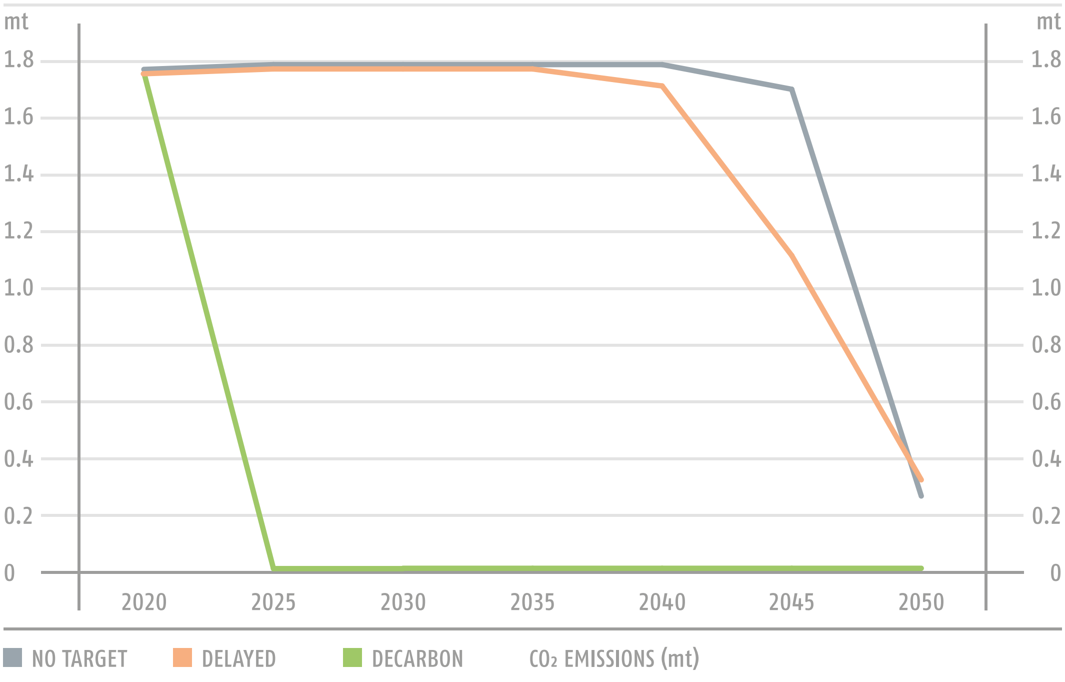


FIGURE 7
CO_2 EMISSIONS UNDER THE 3 CORE SCENARIOS IN MONTENEGRO, 2020-2050 (mt)



The 94% overall CO_2 emission reduction target for the EU28+Western Balkans region translates into a higher than average level of reduction in the Montenegrin electricity sector in the 'decarbonisation' scenario: with the decommissioning of fossil capacities, the electricity sector achieves a 100% emission reduction already by 2025. By 2050 CO_2 emissions are reduced compared to 1990 in the electricity sector in Montenegro by 89.2% and 91.1% in the 'delayed' and 'no target' scenarios respectively. This means that in the scenarios where decommissioned fossil-based generating capacities are replaced by new ones in 2024 (Plevlja 2) , Montenegro falls slightly short of meeting the regional goal of carbon reduction of 94% despite falling fossil-based production between 2040 and 2050. This is due to the fact that Pljevlja 2 will use lignite as a fuel, which has a high emission factor.

The share of renewable generation as a percentage of gross domestic consumption in the 'no target' scenario is 61.2% and 125.6% in 2030 and 2050, respectively. In the 'delayed' and 'decarbonisation' scenarios the share of renewable generation is 165.1% and 147.3% in 2050, respectively. The utilisation of RES technical potential in the scenario with the highest RES share by 2050, the 'delayed' scenario, will reach 92%, 97% and 79% for hydro, wind and solar, respectively. Interestingly, the 'decarbonisation' scenario is expected to bring lower utilisation of RES technical potential, with 85%, 88%, and 51% for hydro, wind and solar, respectively.

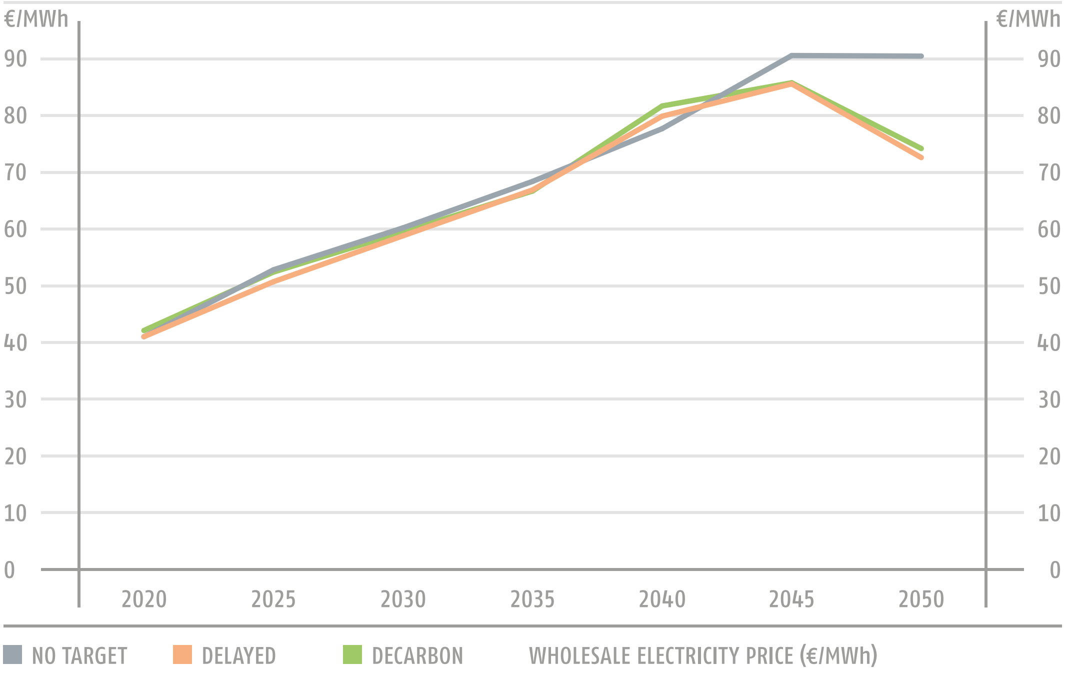
5.4 Affordability and competitiveness

In the market model (EEMM) the wholesale electricity price is determined by the highest marginal cost of the power plants needed to satisfy demand. The price trajectories are independent of the level of decarbonisation and similar in all scenarios, only diverging after 2045 when the two scenarios with decarbonisation targets result in lower wholesale prices. This is due to the fact that towards 2050 the share of renewables is high enough to satisfy demand in most hours at a low cost, driving the average annual price down.

The price development has several implications for policy makers. Retail prices depend on the wholesale price as well as taxes, fees and network costs. It is therefore difficult to project retail price evolution based on wholesale price information alone, but it is an important determinant of end user prices and could affect affordability for consumers. The average annual price increase over the entire period is 3.2% in the 'no target' scenario and 2.5% in the 'delayed' and 'decarbonisation' scenarios; the lower growth rate in these two scenarios is due to a decrease in the wholesale price during the last 5 years of the modelled time period. Although the price increase is high, prices in Europe were at historical lows in 2016 for the starting point of the analysis and will rise to approximately 60 EUR/MWh by 2030, similar to price levels 10 years ago. Still, macroeconomic analysis in Section 5.7 shows that if affordability is measured as the share of household electricity expenditure in disposable income, electricity expenditure increases more moderately compared with current levels, due to a high increase in household income. The price increase also has three positive implications, incentivising investment for new capacities, incentivising energy efficiency and reducing the need for RES support.

The investment needed in new capacities increases significantly between 2020 and 2030 in the 'no target' scenario. The following decade is expected to be less investment-heavy in this scenario, but investments are expected to pick up again between 2040 and 2050. In the 'decarbonisation' scenario, the investments are expected to peak between 2020 and 2030. In the 'delayed' scenario investments peak between 2040 and 2050, reflecting the significant effort needed to meet decarbonisation targets at the end of the period.

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



It is important to note that investments are assumed to be based on a profitability requirement (apart from the capacities planned in the national strategies) and financed by private actors. These actors factor in the different cost structure of renewables, i.e. higher capital expenditure and low operating expenditure in their investment decisions. From a social point of view, the consequences of a change in the overall investment level are limited to the impact on GDP, employment, as well as to the impact on the fiscal and external balance. These impacts are discussed in more detail in section 5.7.

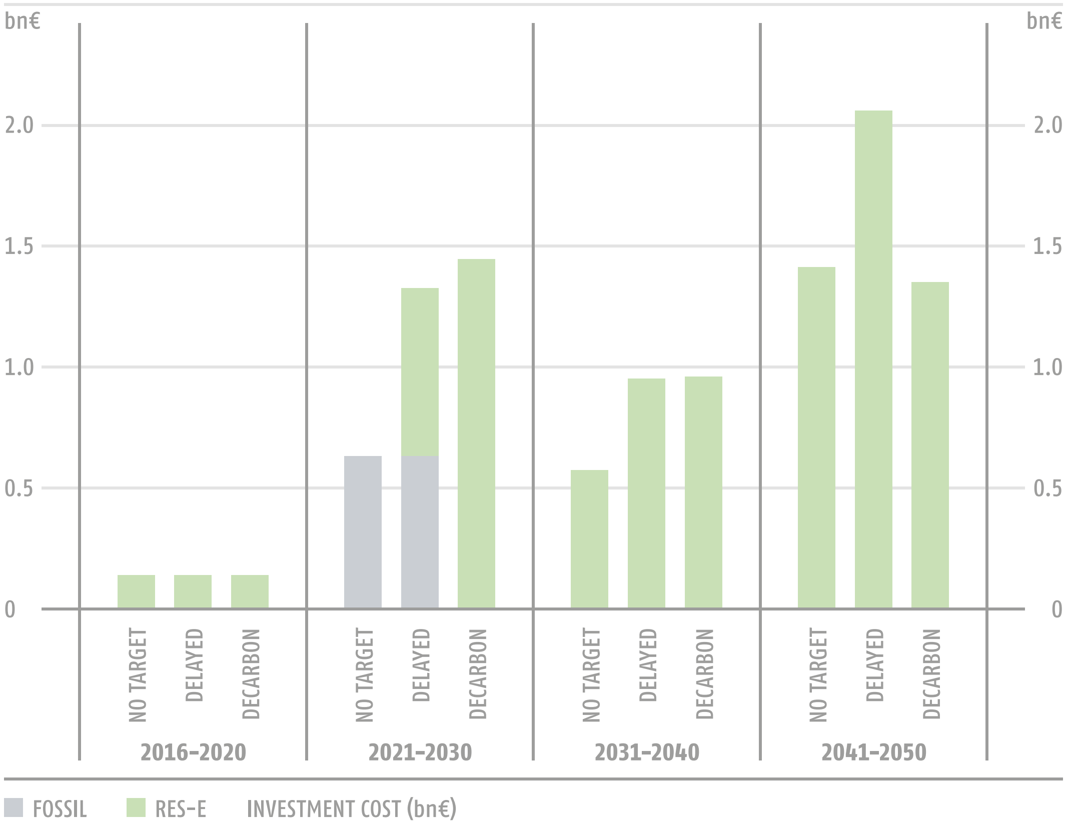
Despite the very significant investment needs associated with the 'decarbonisation' scenario, the renewables support needed to incentivise these investments decreases over time. The RES support needed to achieve complete decarbonisation in this scenario relative to the wholesale price plus RES support is 13% in the period 2020-2025 but only 2% in 2045-2050.

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

Even though no new RES support is assumed in the 'no target' scenario after 2025, RES-based capacities are expected to more than triple between 2025 and 2050. The 'decarbonisation' scenario foresees a decrease in support levels over time from 2030 onwards, from 9.3 EUR/MWh to 1.9 EUR/MWh by 2050. The rapid penetration of RES technologies even without support in the 'no target' scenario, and the decrease in RES support in the 'decarbonisation' scenario is made possible mainly by the increasing wholesale price for electricity which reduces the need for (additional) support.

Renewable energy investments may be incentivised with a number of support schemes using funding from different sources; in the model sliding feed-in premium equivalent values are calculated. Revenue from the auction of carbon allowances under the EU ETS is

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



a potential source of financing for renewable investment. Figure 12 contrasts cumulative RES support needs with ETS auction revenues, assuming 100% auctioning, and taking into account only allowances to be allocated to the electricity sector.

In the 'decarbonisation' scenario, there are no auction revenues, as only fossil fuel based plants receive an allocation under the EU Emissions Trading Scheme, and these plants disappear from the Montenegrin capacity mix by 2025 under this scenario. In the 'delayed' scenario, ETS revenues are expected to surpass the cost of RES support between 2030 and 2040, but the costs of support are significantly higher than the auction revenues in the following decade. As the need for RES support in this scenario rises significantly between 2040 and 2050, the balance of costs and revenues makes this option more expensive in this period than the 'decarbonisation' scenario.

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

Large stranded capacities might call for public intervention with all the associated cost borne by society/electricity consumers. For this reason we have estimated the stranded costs of fossil based generation assets that were built in the period 2017-2050. The

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

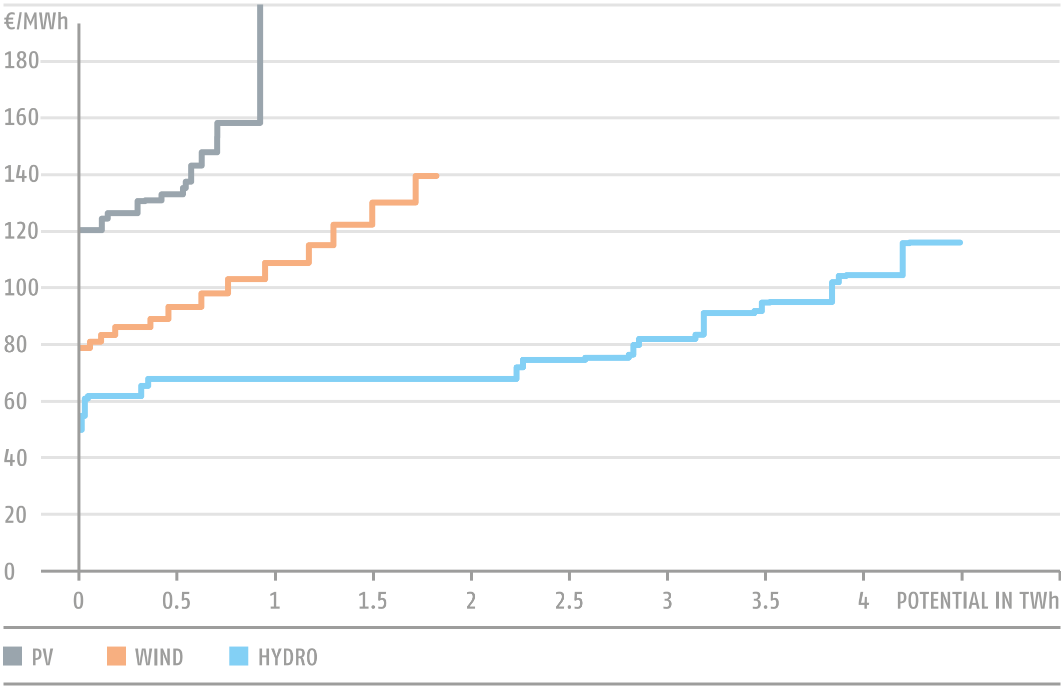


FIGURE 11
AVERAGE RES SUPPORT PER MWh OF TOTAL ELECTRICITY CONSUMPTION AND AVERAGE WHOLESALE PRICE, 2016-2050 (€/MWh)

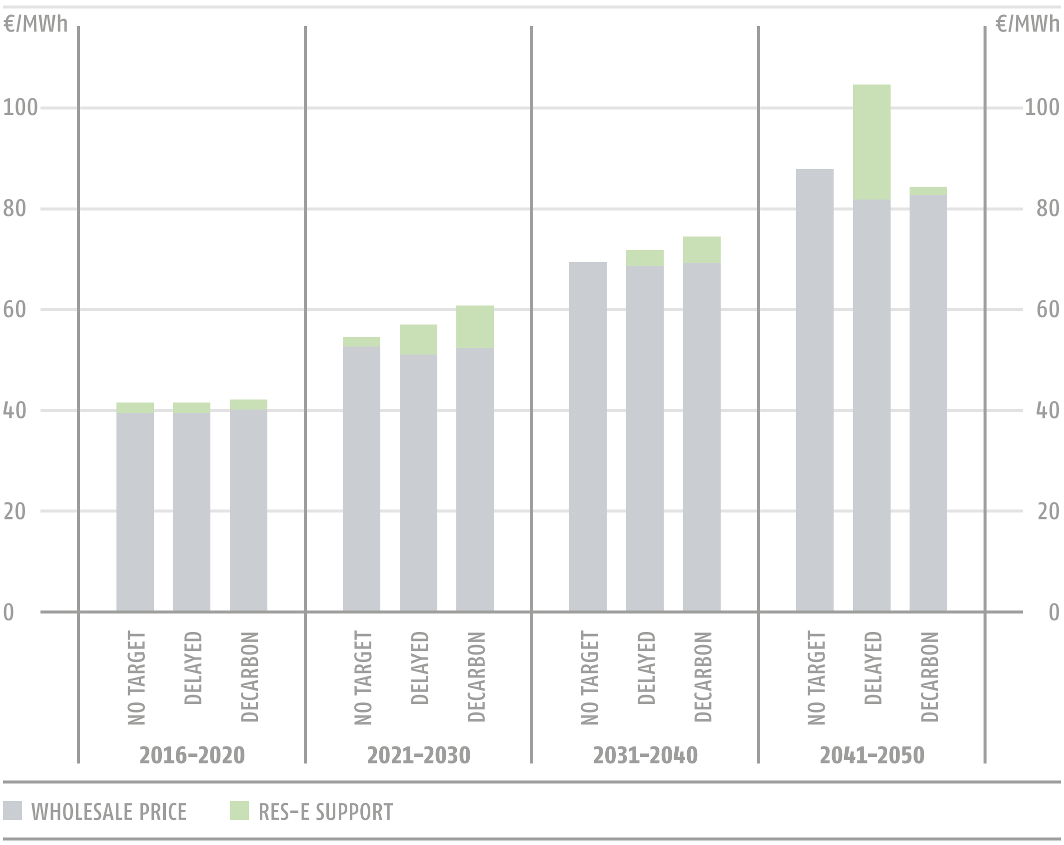
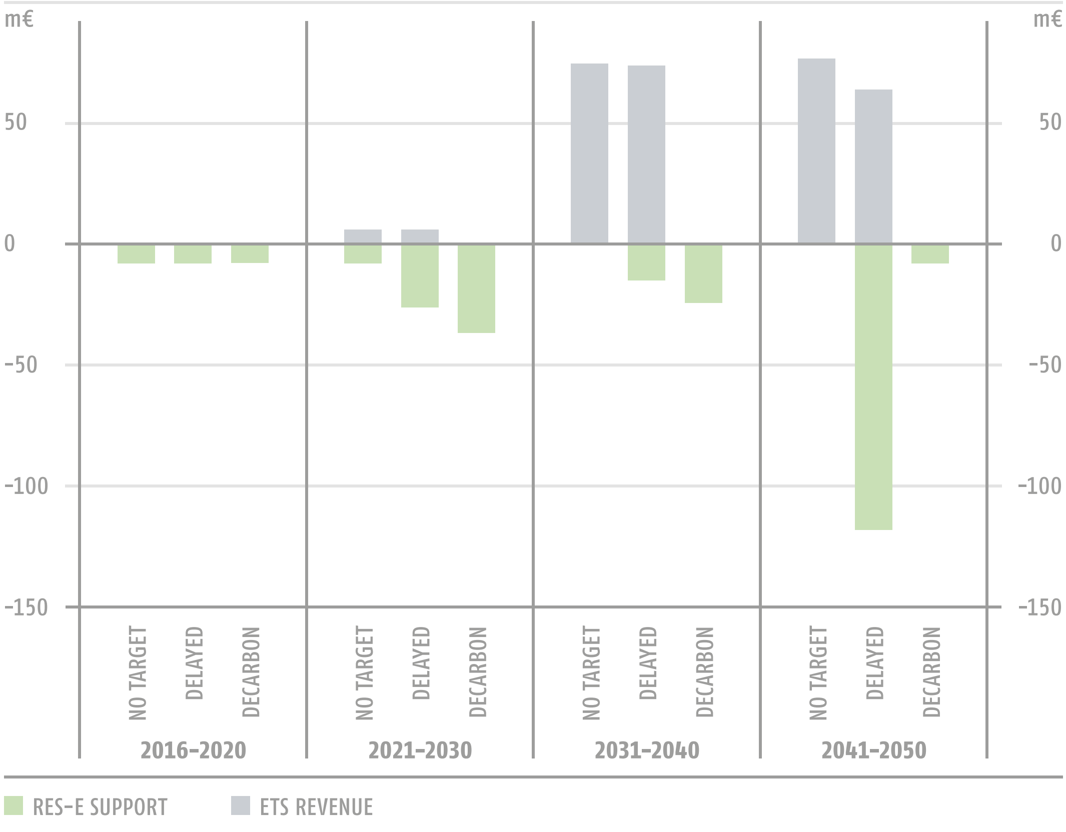


FIGURE 12
CUMULATIVE RES SUPPORT AND AUCTION REVENUES FOR 4 AND 10 YEAR PERIODS, 2016-2050 (m€)



calculation is based on the assumption that stranded costs will be collected as a surcharge on the consumed electricity (as is the case for RES surcharges) for over a period of 10 years after the these lignite based capacities become unprofitable.

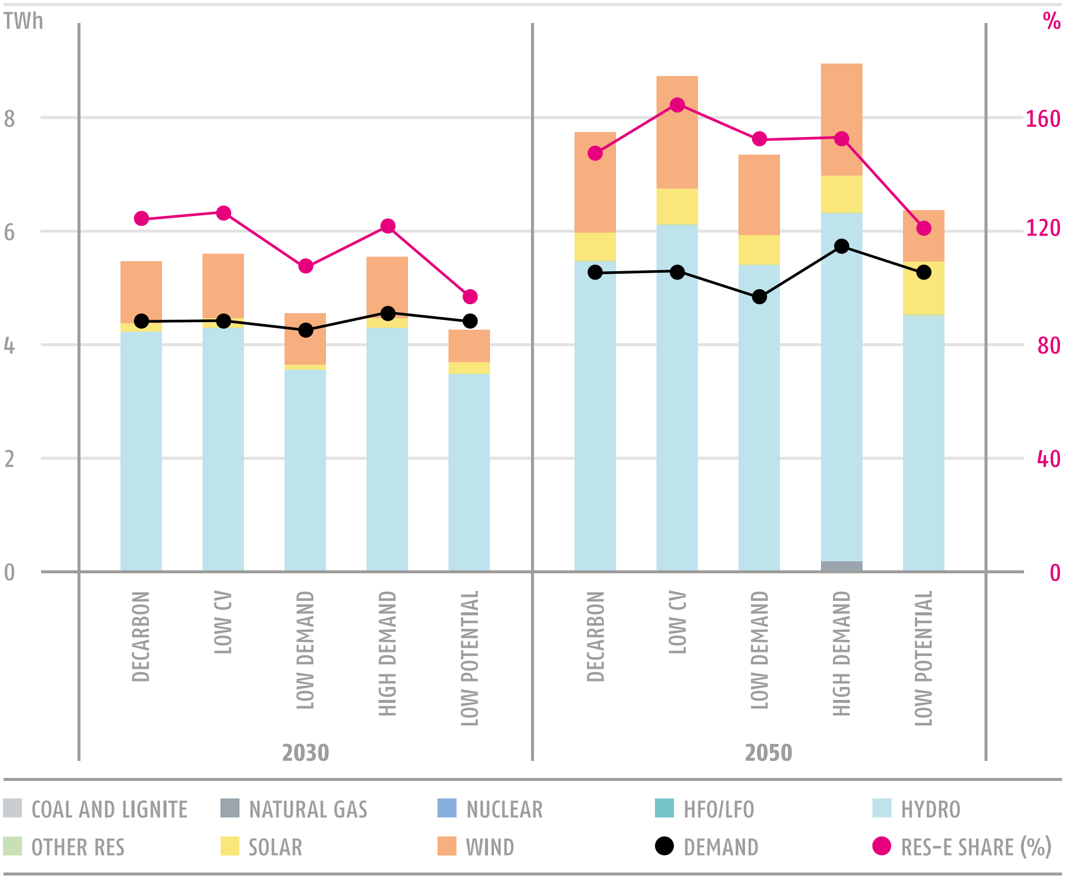
Based on this calculation unprofitable lignite-fired plants would have to receive a surcharge of 2.7 EUR/MWh and 2.8 EUR/MWh over a 10 year period to cover their economic losses in the 'no target' and 'delayed' scenarios, respectively. These costs are not included in the wholesale price values shown in this report. With no new fossil based capacity commissioned in the 'decarbonisation' scenario, no stranded costs occur.

5.5 Sensitivity analysis

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

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

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



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

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

- The CO_2 price is a key determinant of wholesale prices. A 50% reduction in the value of the carbon price results in an approximately 33% reduction in the wholesale price over the long term. However, in order to ensure that the same decarbonisation target is met, a higher RES support is required in this scenario which more than compensates for lower wholesale prices.
- Renewable support is also sensitive to demand, with required RES support significantly higher in a high demand scenario;
- High demand results in 450 MW higher RES deployment by 2050 than the 'decarbonisation' scenario, and the deployment of 100 MW natural gas capacity. Low demand, decreases RES-based capacities by around 180 MW.
- Lower hydro and wind potential doubles PV based capacity, and increases solar generation by 2.6 times. As solar technology is more expensive, it requires more support, this sensitivity run therefore results in significantly higher RES support requirements. It also results in a decrease in net exports as Montenegrin electricity generation loses some of its competitive edge with less low cost hydro based capacity available.

5.6 Network

Montenegro's transmission system is already well-connected with the neighbouring countries. In the future further new network investments are expected to be realised, in order to cope with higher RES integration and cross-border electricity trade. Peak load is expected to increase significantly, this will also have an impact on network development needs. For 2016 the recorded peak load on the transmission network of Montenegro was 576 MW (ENTSO-E DataBase), while the projected value for 2030 is 2039.6 MW (SECI DataBase) and for 2050 it is 2489.5 MW. Internal high and medium voltage transmission lines, as well as the distribution level will need investment.

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

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

- **Contingency analysis:** Analysis of the network constraints foresees several contingencies. Because of the projected tripping of the 110 kV overhead line connecting Bar and the Mozura Wind Power Plant, a new line needs to be built connecting the power plant with Ulcinj at a projected cost of 3.5 mEUR in the 'delayed' scenario. In the 'decarbonisation' scenario, an additional investment of 8 mEUR may become necessary for another line connecting Virpazar, Golubovci and Podgorica. A new substation for RES collection may become necessary at Brezna, incurring a cost of 20 mEUR. Furthermore, constraints on lines connecting the Perucica Hydro Power Plant to the grid may call for a new line between Vilusi and Herceg Novy at a cost of 5.5 mEUR.

TABLE 1 | OVERLOADINGS IN THE MONTENEGRIN SYSTEM, 2030

	Overloading	Solution	Units (km or pcs)	Cost m€
Delayed	WPP Mozura must go out of operation	New OHL 110 kV Ulcinj (ME) – Virpazar (ME)	40	3.50
Decarbon	WPP Mozura must go out of operation	New OHL 110 kV Ulcinj (ME) – Virpazar (ME) & OHL 110 kV Virpazar – Golubovci – Podgorica 1	80	8.00
	OHL 110 kV Brezna (ME) – Klicevo (ME)	New SS 400/110 kV Brezna for RESs collection	1	20.00
	OHL 110 kV HPP Perucica – Podgorica	New OHL 110 kV Vilusi (ME) – H. Novi (ME)	40	5.50

- **TTC and NTC assessment:** Total and Net Transfer Capacity (TTC/NTC) changes were evaluated between Montenegro and all of its neighbours, for all scenarios 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

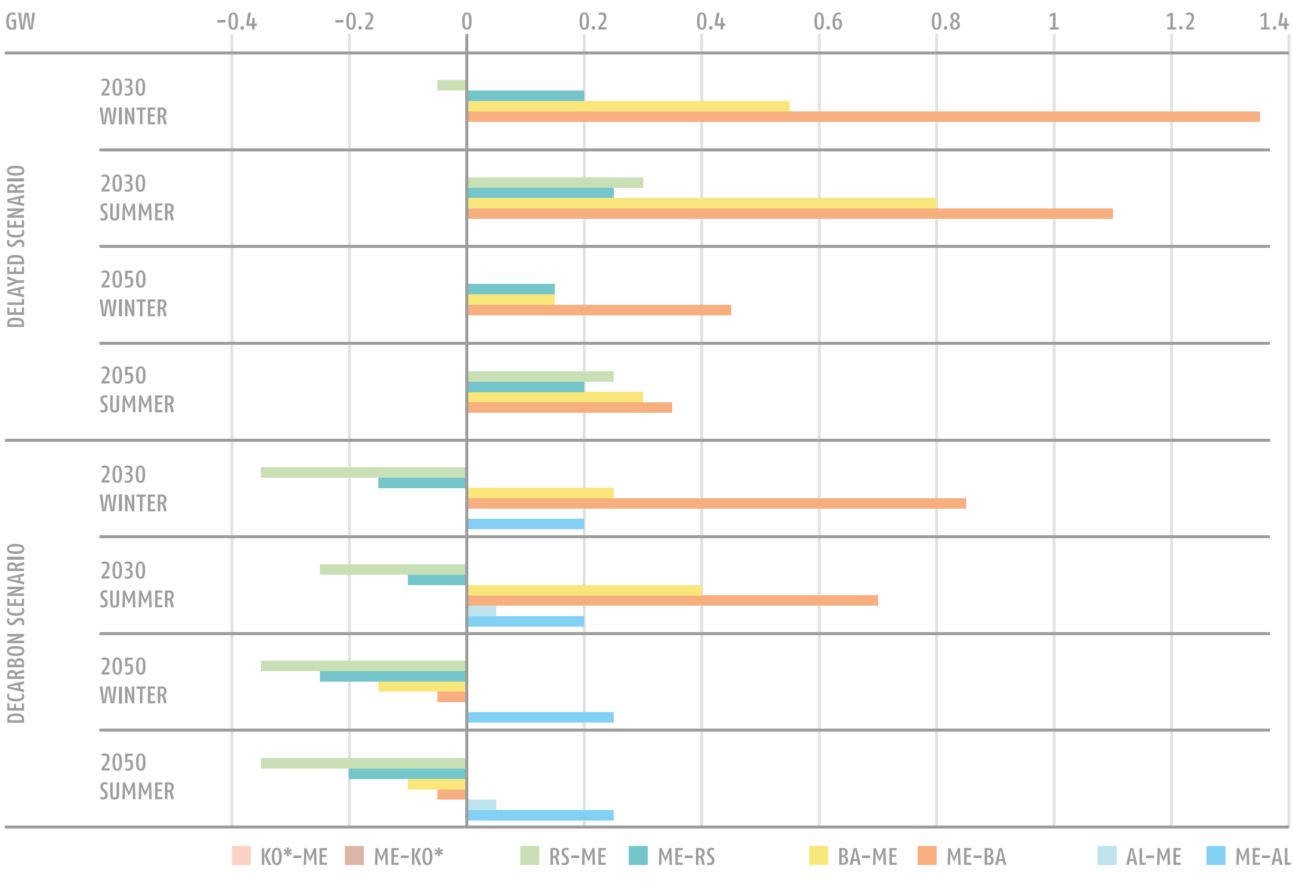


FIGURE 14
NTC VALUE CHANGES IN 2030 AND 2050 IN THE 'DELAYED' AND 'DECARBONISATION' SCENARIOS COMPARED TO THE 'BASE CASE' SCENARIO

latter of which is not known) have a significant influence on NTC values between the Montenegrin and the neighbouring electricity systems. Figure 14 presents the changes in NTC values for 2030 and 2050. We can distinguish two opposite impacts of higher RES deployments on the NTC values. First, high concentration of RES in a geographic area may cause congestion of the transmission network reducing NTCs and requiring further investment. Second, if RES generation replaces imported electricity, it may increase NTC for a given direction.

As the results show, NTC values generally increase in the 'delayed' scenario. Results are mixed in the 'decarbonisation' scenario: by 2050, NTCs are expected to be lower in most relations compared to the base case, highlighting the congestion effect. NTC changes are projected to be the most significant in relation with Serbia and Bosnia. Exports to Albania may be boosted by higher NTC in the 'decarbonisation' scenario.

- **Network losses:** Transmission network losses are affected in different ways. On the one hand losses are reduced as renewables, especially PV, are connected mostly to the distribution network, reducing the distance between generation and consumption. On the other hand, high levels of electricity trade, in particular in 2050, will increase transmission network losses. Figure 15 shows that in the 'decarbonisation' scenario transmission losses decrease significantly compared to the base case. In the 'delayed' scenario, the decrease is only evident in 2050.

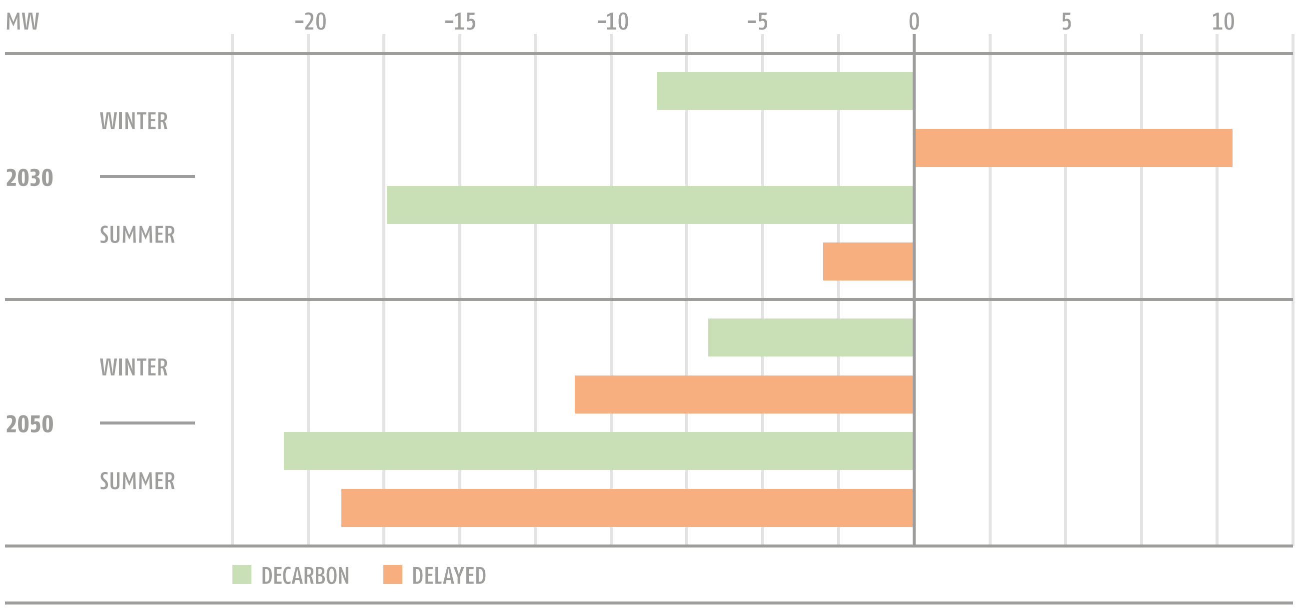


FIGURE 15
LOSS VARIATION COMPARED TO THE BASE CASE IN THE 'DELAYED' AND 'DECARBONISATION' SCENARIOS (MW, NEGATIVE VALUES INDICATE LOSS REDUCTION)

In the 'decarbonisation' scenario, network loss may decrease by over 50 GWh in both 2030 and in 2050. In the 'delayed' scenario, an increase of almost 20 GWh of network loss is forecasted in 2030, but this turns into a gain of 60 GWh by 2050. If monetised at the base-load price, the concurrent benefit of a 50 GWh reduction in network loss for TSOs is almost 4 mEUR per year.

Overall, a moderate amount of investment in the transmission network is necessary to accommodate new RES capacities in the Montenegrin electricity system in addition to ENTSO-E TYNDP (2016). The estimated cost of network investments is over 30 mEUR for the period. This figure includes not only the transmission network costs, but the necessary connecting facilities, as well as reinforcement of the national grid to facilitate the expected increase in RES generation. It does not include, however, investment needs related to the development of the distribution network, which may be significant due to the increase in solar generation capacity in particular.

5.7 Macroeconomic impacts

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

In the 'baseline' scenario, we expect the Montenegrin economy to grow by an average of 2.4% per annum over the projection horizon, slightly above the regional average. Nonetheless, this reflects a slowdown from the current robust (3.5%) level to around 2% by 2026-2030, as current rates have been largely fuelled by increasing fiscal deficit and large infrastructural spending leading to ballooning external and public debt levels. Employment growth will remain close to zero until 2050 reflecting a rigid labour market and the lack of an ability to create jobs. Gross government debt is expected to peak at around 80% of GDP and stabilize at that level later on. Gross external debt will gradually decrease from

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

an elevated level of above 140% of GDP, and stabilize at around 80% in the medium term. These levels can still be considered high given the relatively low level of GDP per capita, hence could be a source of considerable vulnerability.

The share of electricity expenditures in household disposable income was at around 4.0% in 2016, which is higher than the regional average of 2.5% and hence higher than the EU level of 2.9%. An increase to around 6.5% is projected mainly due to increasing real wholesale prices. At the same time the effect of renewable support on household electricity expenditure remains moderate.

The core scenarios exhibit a significant investment effort compared to the baseline. In all three scenarios investment is mainly concentrated in the 2021-2025 period, with an effect ranging from around 2.5% of GDP in the 'no target', 4% in the 'decarbonisation' to around 5.0% in the 'delayed' scenario. Additional investment is most persistent in the 'decarbonisation' scenario, phasing out only gradually throughout the horizon.

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

Results from the core scenarios suggest significant macroeconomic gains compared to the baseline. In the 'delayed' and 'decarbonisation' scenarios. The GDP level could be higher by around 6-6.5%, while gains are somewhat less pronounced in the 'no target' scenario, with a 2% increase on average until 2050. Long term GDP gains are higher and amount to around 10% and 9% in the 'delayed' and 'decarbonisation' scenarios, respectively, when compared to the 'baseline' scenario at the end of the projection horizon. The 'no target' scenario exhibits less marked gains, with a difference of 2.5% in GDP. These differences reflect different investment efforts in the scenarios. Employment effects are negligible in all three core scenarios. However, it is to be noted that in the long term,

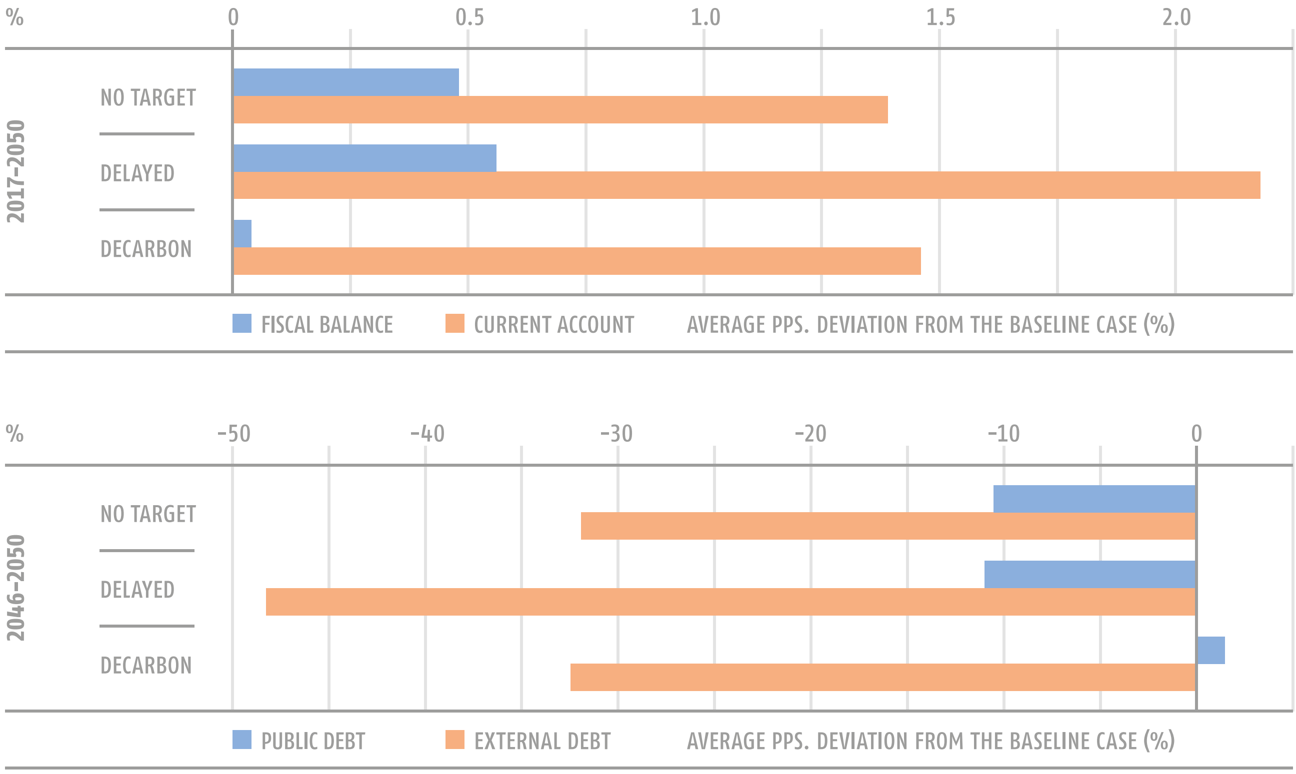


FIGURE 17
PUBLIC AND EXTERNAL BALANCES AND DEBT IMPACTS COMPARED WITH THE 'BASELINE' SCENARIO

the 'decarbonisation' scenario has a slight negative impact on employment, around -1% compared to the 'baseline' scenario.

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

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

The core scenarios improve the macroeconomic vulnerability of Montenegro quite visibly compared to the baseline. External debt levels are projected to decrease significantly in the 'no target' and 'delayed' scenarios, up to 30 and 50% of GDP, respectively, while public debt levels also decrease by around 10% of GDP. The difference in case of the 'decarbonisation' scenario is somewhat less marked but still significant with a fall of around 30% in the external debt and essentially unchanged levels of public debt. Differences in the external debt profiles are primarily explained by the fact that net energy exports (mainly electricity) increase in all scenarios: in particular in the 'no target' and 'delayed' scenarios, peaking at close to 3% of GDP in the 2030-2045 period, and more moderately in the 'decarbonisation' scenario.

FIGURE 18
HOUSEHOLD ELECTRICITY EXPENDITURE 2017-2050

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 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 is slightly greater compared to the baseline. The fiscal balance improves convincingly at around 0.8% of GDP from 2035 in the 'delayed' and 'no target' scenarios, due to higher carbon allowance revenues, reflecting the effect of significant fossil investments. Public sector revenues are slightly lower in the 'decarbonisation' scenario compared to the baseline on account of lower carbon allowance revenues. A higher fiscal deficit also leads to smaller current account gains in this scenario compared to the other two scenarios.

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.

Household electricity expenditure relative to disposable income remains broadly unchanged in the 'no target' scenario compared to the 'baseline' scenario. Similarly to other countries in the region, one can also observe a close to 10% decline in expenditure in the 2046-2050 period in the 'decarbonisation' scenario, which is primarily due to the large fall in real wholesale electricity prices at the end of the simulation horizon. This latter effect is more than offset by higher feed-in tariffs in the 'delayed' scenario leading to a 25% deterioration in affordability at the end of the projection horizon.

6 | Policy conclusions

The modelling work carried out under the SEERMAP project identifies some key findings with respect to the different electricity strategy approaches that Montenegro can take. We review these findings and suggest some policy relevant insights. **The analysis has uncovered some robust findings which are relevant for all scenarios, based on which no regret policy options can be identified.**

MAIN POLICY CONCLUSIONS

Regardless of whether or not Montenegro pursues an active policy to decarbonise its electricity sector, the share of renewable energy in the generation mix will increase significantly:

- Even if Montenegro replaces decommissioned fossil capacities with new ones in a 'no target' or 'delayed' scenario, 96% of generation will come from RES by 2050 according to modelling results. In the 'decarbonisation' scenario, there is no fossil-based generation from 2025;
- In all scenarios, the share of renewable energy will increase significantly as a result of the deteriorating competitiveness of fossil fuel technologies and an increase in the electricity wholesale price;
- The high penetration of RES found in all scenarios suggests that Montenegrin energy policy should focus on enabling RES integration;

A long term planned effort to decarbonise the electricity sector has significant benefits, but also poses some challenges:

- The 'decarbonisation' scenario demonstrates that it is technically possible and financially viable to reach 100% of decarbonisation for Montenegro with its abundant RES resources by 2030;
- Long term planned support for RES does not drive wholesale prices up relative to other scenarios with less ambitious RES policies, but on the contrary, it reduces them after 2045;
- Decarbonisation does not jeopardise Montenegro's position as a net electricity exporter, installed generating capacity within the country enables Montenegro to satisfy domestic demand using domestic generation in all seasons and hours of the day, with higher shares of net exports than in the 'no target' scenario;
- The macroeconomic analysis shows that household electricity expenditure relative to household income is expected to increase over time, but the increase is smallest in the decarbonisation scenario;
- Long term planned support for RES reduces the cost of stranded investments from 2.7 EUR/MWh in the 'no target' scenario to zero;
- Decarbonisation will require a significant increase in investment from about to 2.8 bnEUR to about 3.9 bnEUR over the 35-year period. Although these will be funded by private investors, Montenegro will need to create an environment which is conducive to investment.

6.1 Main electricity system trends

Montenegro is already in an advantageous position in terms of RES-generation due to a large share of hydro capacities, which accounted for 75% of total installed capacity in 2015. The total lignite capacity currently installed, 219 MW, will need to be decommissioned by 2023 according to national plans, in line with Energy Community Acquis commitments. Several options are available to ensure that electricity demand is met in future.

Lignite becomes insignificant as a source of electricity generation in all scenarios by 2050. Despite investment in new lignite capacity in the 'no target' and 'delayed' scenarios according to national plans, the contribution of lignite to electricity generation is by 2050 is less than 4% in both scenarios. This is driven mainly by the high carbon price, as well as the increase in competitiveness of renewable technologies over time.

Hydro maintains its role as the prominent source of power generation. Its current share of 62% of total generation increases to above 70% in both the 'decarbonisation' and the 'no target' scenarios by 2050. **In the 'decarbonisation' scenario the share of wind power in total generation rises to 23% by 2050** from only 4% in 2020, but it reaches 19% even under the 'no target' scenario.

The share of RES in electricity consumption will reach approximately 125% in 2050 in the 'no target' scenario; in the 'delayed' and 'decarbonisation' scenarios the RES share is 165% and 147%, respectively.

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

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

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 in power plants which are currently planned. Translated into a price increase over a 10 year period, the cost of stranded assets is estimated at 2.8 EUR/MWh, compared with no stranded costs in the 'decarbonisation' scenario. 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 all scenarios, Montenegro produces significantly more electricity than it consumes. Its generation and system adequacy indicators also remain favourable; installed generation capacity within the country enables Montenegro to satisfy domestic demand using domestic generation in all seasons and hours of the day, throughout the modelled period.

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

The network modelling results suggest that Montenegro would need to invest in its transmission and distribution network. More than 30 mEUR of investment is estimated to be needed in the Montenegrin network system in addition to planned investment already included in ENTSO-E TYNDP (2016), in order to ensure higher RES integration and cross-border electricity trade.

6.3 Sustainability

Montenegro has a high potential of renewables, in particular hydro and wind. Montenegro can make a higher than average contribution to meeting 2050 emission reduction targets compared to other countries in the region. In Montenegro CO_2 emissions are reduced in the electricity sector by 100% in the 'decarbonisation' scenario. Although the reduction in the 'delayed' scenario is around 90%, slightly less than the 94% target set for the EU28+Western Balkans region as a whole, the rate at which Montenegro is able to speed up its RES deployment at the end of the period highlights the flexibility it can provide on a regional level.

This potential can be reaped through policies eliminating barriers to RES investment. **A no-regret step involves de-risking policies addressing the high cost of capital.** This would allow for cost-efficient renewable energy investment.

6.4 Affordability and competitiveness

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 decarbonisation but by the CO_2 price, which is applied across all scenarios, and the price of natural gas, because natural gas based production is the marginal production unit within the region needed to meet demand in the region 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; this is due to the low marginal cost of RES electricity production.

Under all scenarios there is a significant increase in the wholesale electricity price compared with current (albeit historically low) price levels. This increase is driven by the price of carbon and the price of natural gas, both of which increase significantly by 2050. This has implications for affordability. The macroeconomic analysis shows that electricity expenditure as a share of household income will grow from 4 to 6% by 2050, and even to 8% in the 'delayed' scenario. Electricity remains most affordable over the long term in the 'decarbonisation' scenario. However, the price increase also has a positive impact in terms of attracting 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.

Decarbonisation will necessitate a 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. Montenegro will need to create an environment which enables this investment.

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 may mitigate volatility. 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 of RES technologies imply that the profitability of the investment is very sensitive to the cost of capital, which is significantly higher in the entire SEE region than in the Western European member states. Although much of the value of the cost of capital depends on country risk linked to the general macroeconomic performance of a country, **the cost of capital can be reduced to some extent through interventions by policy makers, first by ensuring a stable policy framework, and by putting in place de-risking measures. As outlined above, such measures are no-regret steps, as they yield minimised system costs and consumer expenditures.**

In scenarios where continuous RES support is provided to renewable electricity producers during the entire period until 2050, **the need for support is limited by increasing electricity wholesale prices which incentivise significant RES investment even without support.** Continued support also provides 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	219	219	0	0	0	0	0	0
		New	0	0	250	250	250	250	250	250
	Natural gas	Existing	0	0	0	0	0	0	0	0
		New	0	0	0	0	0	0	0	0
	Nuclear	Existing	0	0	0	0	0	0	0	0
		New	0	0	0	0	0	0	0	0
	HFO/LFO		0	0	0	0	0	0	0	0
	Hydro		668	671	671	671	746	893	1 144	1 325
	Wind		0	90	90	92	101	207	535	674
	Solar		3	12	12	12	22	57	157	325
	Other RES		0	0	0	0	0	0	0	2
Gross consumption, GWh			3 440	3 808	4 071	4 407	4 567	4 803	5 024	5 235
Net electricity generation, GWh	Total		4 006	4 187	4 512	4 516	4 824	5 610	7 190	6 848
	Coal and lignite		1 493	1 493	1 818	1 818	1 818	1 818	1 730	273
	Natural gas		0	0	0	0	0	0	0	0
	Nuclear		0	0	0	0	0	0	0	0
	HFO/LFO		0	0	0	0	0	0	0	0
	Hydro		2 499	2 511	2 511	2 511	2 791	3 340	4 279	4 954
	Wind		10	171	171	175	193	395	1 022	1 286
	Solar		5	12	12	12	22	58	158	327
	Other RES		0	0	0	0	0	0	1	8
Net import, GWh	Total		-566	-379	-440	-108	-257	-808	-2 165	-1 613
	BA_SRP		1 977	3 226	1 962	1 782	1 727	2 332	1 846	282
	KO		-69	319	805	225	144	92	985	207
	RS		-440	1 270	4 017	6 697	2 523	3 834	5 560	-549
	AL		-2 034	-865	1 272	120	769	629	2 396	832
	IT		0	-4 330	-8 497	-8 933	-5 420	-7 694	-12 953	-2 386
Net import ratio, %			-16.5%	-9.9%	-10.8%	-2.5%	-5.6%	-16.8%	-43.1%	-30.8%
RES-E share (RES-E production/gross consumption, %)			73.1%	70.7%	66.2%	61.2%	65.8%	79.0%	108.7%	125.6%
Utilisation rates of RES-E technical potential, %	Hydro		na	na	na	na	na	na	na	76%
	Wind		na	na	na	na	na	na	na	63%
	Solar		na	na	na	na	na	na	na	34%
Utilisation rates of conventional power production, %	Coal and lignite		78.0%	78.0%	83.0%	83.0%	83.0%	83.0%	79.0%	12.5%
	Natural gas		na	na	na	na	na	na	na	na
	Nuclear		na	na	na	na	na	na	na	na
Natural gas consumption of power generation, TWh			0	0	0	0	0	0	0	0
Security of supply	Generation adequacy margin		65%	55%	51%	42%	49%	73%	119%	139%
	System adequacy margin		364%	421%	705%	654%	643%	660%	961%	893%
CO_2 emission	Emission, Mt CO_2		1.8	1.8	1.8	1.8	1.8	1.8	1.7	0.3
	CO_2 emission reduction compared to 1990, %		41.0%	41.0%	40.4%	40.4%	40.4%	40.4%	43.3%	91.1%
Spreads	Clean dark spread, €(2015)/MWh		25.4	30.8	42.8	14.7	13.5	13.9	6.6	-13.6
	Clean spark spread, €(2015)/MWh		-2.9	-0.5	5.3	-5.2	-4.6	-5.7	-2.6	-10.9
Price impacts	Electricity wholesale price, €(2015)/MWh		34.7	41.0	52.8	60.2	68.4	77.7	90.6	90.5
	Total RES-E support/gross consumption, €(2015)/MWh, five year average		na	2.0	2.3	1.2	0.1	0	0	0
	Revenue from CO_2 auction/gross consumption, €(2015)/MWh		0	0	0	13.6	16.4	18.6	23.4	4.5
Investment cost, m€/5 year period	Coal and lignite		na	0	634	0	0	0	0	0
	Natural gas		na	0	0	0	0	0	0	0
	Total Fossil		na	0	634	0	0	0	0	0
	Total RES-E		na	142	0	0	117	459	842	573
	Total		na	142	634	0	117	459	842	573
Main assumptions	Coal price, €(2015)/GJ		1.78	1.95	1.93	1.89	1.98	2.04	2.04	2.04
	Lignite price, €(2015)/GJ		0.98	1.07	1.06	1.04	1.09	1.12	1.12	1.12
	Natural gas price, €(2015)/MWh		18.79	20.74	23.78	25.98	28.07	31.64	32.72	33.00
	CO_2 price, €(2015)/t		8.60	15.00	22.50	33.50	42.00	50.00	69.00	88.00

TABLE A2 | 'DELAYED' SCENARIO

			2016	2020	2025	2030	2035	2040	2045	2050
Installed capacity, MW	Coal, lignite	Existing	219	219	0	0	0	0	0	0
		New	0	0	250	250	250	250	250	250
	Natural gas	Existing	0	0	0	0	0	0	0	0
		New	0	0	0	0	0	0	0	0
	Nuclear	Existing	0	0	0	0	0	0	0	0
		New	0	0	0	0	0	0	0	0
	HFO/LFO		0	0	0	0	0	0	0	0
	Hydro		668	671	868	874	874	1 116	1 379	1 597
	Wind		0	90	367	373	381	600	854	1 035
	Solar		3	12	47	54	129	316	525	762
	Other RES		0	0	0	0	0	0	1	4
Gross consumption, GWh			3 440	3 808	4 074	4 409	4 569	4 800	5 032	5 263
Net electricity generation, GWh	Total		4 006	4 187	5 814	5 854	5 944	7 395	8 444	9 018
	Coal and lignite		1 493	1 493	1 818	1 818	1 818	1 757	1 134	331
	Natural gas		0	0	0	0	0	0	0	0
	Nuclear		0	0	0	0	0	0	0	0
	HFO/LFO		0	0	0	0	0	0	0	0
	Hydro		2 499	2 511	3 247	3 269	3 269	4 174	5 152	5 950
	Wind		10	171	701	712	727	1 145	1 627	1 966
	Solar		5	12	47	54	129	318	526	756
	Other RES		0	0	1	1	1	1	4	15
Net import, GWh	Total		-566	-379	-1 740	-1 445	-1 375	-2 596	-3 411	-3 754
	BA_SRP		1 560	3 215	1 728	1 695	2 328	2 103	-491	-477
	KO		119	635	872	45	-578	132	316	297
	RS		-186	987	3 042	1 274	-4 827	-2 234	-252	-3 250
	AL		-2 060	-835	1 596	-136	-277	28	753	977
	IT		0	-4 380	-8 978	-4 322	1 979	-2 626	-3 738	-1 302
Net import ratio, %			-16.5%	-9.9%	-42.7%	-32.8%	-30.1%	-54.1%	-67.8%	-71.3%
RES-E share (RES-E production/gross consumption, %)			73.1%	70.7%	98.1%	91.5%	90.3%	117.5%	145.2%	165.1%
Utilisation rates of RES-E technical potential, %	Hydro		na	na	na	na	na	na	na	92%
	Wind		na	na	na	na	na	na	na	97%
	Solar		na	na	na	na	na	na	na	79%
Utilisation rates of conventional power production, %	Coal and lignite		78.0%	78.0%	83.0%	83.0%	83.0%	80.2%	51.8%	15.1%
	Natural gas		na	na	na	na	na	na	na	na
	Nuclear		na	na	na	na	na	na	na	na
Natural gas consumption of power generation, TWh			–	–	–	–	–	–	–	–
Security of supply	Generation adequacy margin		65%	55%	92%	81%	76%	117%	164%	186%
	System adequacy margin		364%	421%	746%	693%	669%	708%	967%	892%
CO_2 emission	Emission, Mt CO_2		1.8	1.8	1.8	1.8	1.8	1.7	1.1	0.3
	CO_2 emission reduction compared to 1990, %		41.0%	41.0%	40.4%	40.4%	40.4%	42.4%	62.8%	89.2%
Spreads	Clean dark spread, €(2015)/MWh		25.4	30.8	40.6	13.4	12.0	16.2	1.6	-31.5
	Clean spark spread, €(2015)/MWh		-2.9	-0.5	3.1	-6.6	-6.1	-3.4	-7.6	-28.8
Price impacts	Electricity wholesale price, €(2015)/MWh		34.7	41.0	50.7	58.8	66.9	79.9	85.6	72.6
	Total RES-E support/gross consumption, €(2015)/MWh, five year average		na	2.0	9.5	2.2	1.8	4.6	6.9	38.8
	Revenue from CO_2 auction/gross consumption, €(2015)/MWh		0	0	0	13.6	16.4	18.0	15.3	5.4
Investment cost, m€/5 year period	Coal and lignite		na	0	634	0	0	0	0	0
	Natural gas		na	0	0	0	0	0	0	0
	Total Fossil		na	0	634	0	0	0	0	0
	Total RES-E		na	142	677	18	70	884	1 203	860
	Total		na	142	1 311	18	70	884	1 203	860
Main assumptions	Coal price, €(2015)/GJ		1.78	1.95	1.93	1.89	1.98	2.04	2.04	2.04
	Lignite price, €(2015)/GJ		0.98	1.07	1.06	1.04	1.09	1.12	1.12	1.12
	Natural gas price, €(2015)/MWh		18.79	20.74	23.78	25.98	28.07	31.64	32.72	33.00
	CO_2 price, €(2015)/t		8.60	15.00	22.50	33.50	42.00	50.00	69.00	88.00

TABLE A3 | 'DECARBONISATION' SCENARIO

			2016	2020	2025	2030	2035	2040	2045	2050
Installed capacity, MW	Coal, lignite	Existing	219	219	0	0	0	0	0	0
		New	0	0	0	0	0	0	0	0
	Natural gas	Existing	0	0	0	0	0	0	0	0
		New	0	0	0	0	0	0	0	0
	Nuclear	Existing	0	0	0	0	0	0	0	0
		New	0	0	0	0	0	0	0	0
	HFO/LFO		0	0	0	0	0	0	0	0
	Hydro		668	671	907	1 131	1 246	1 371	1 466	1 466
	Wind		0	90	504	572	603	686	779	934
	Solar		3	12	54	143	293	449	496	498
	Other RES		0	0	1	1	1	1	1	3
Gross consumption, GWh			3 440	3 807	4 072	4 408	4 569	4 797	5 032	5 261
Net electricity generation, GWh	Total		4 006	4 187	4 412	5 469	6 110	6 890	7 461	7 749
	Coal and lignite		1 493	1 493	0	0	0	0	0	0
	Natural gas		0	0	0	0	0	0	0	0
	Nuclear		0	0	0	0	0	0	0	0
	HFO/LFO		0	0	0	0	0	0	0	0
	Hydro		2 499	2 511	3 394	4 231	4 661	5 127	5 475	5 465
	Wind		10	171	961	1 093	1 152	1 309	1 484	1 776
	Solar		5	12	54	143	295	452	496	495
	Other RES		0	0	2	2	2	2	5	13
Net import, GWh	Total		-566	-380	-340	-1 061	-1 541	-2 093	-2 429	-2 488
	BA_SRP		1 560	2 280	741	1 153	482	1 898	-353	-525
	KO		119	486	53	-397	-271	-292	-194	-510
	RS		-186	2 113	2 166	27	-3 519	-2 683	-4 228	-5 983
	AL		-2 060	-1 060	212	565	114	383	-4	-262
	IT		0	-4 200	-3 512	-2 408	1 653	-1 399	2 349	4 792
Net import ratio, %			-16.5%	-10.0%	-8.3%	-24.1%	-33.7%	-43.6%	-48.3%	-47.3%
RES-E share (RES-E production/gross consumption, %)			73.1%	70.8%	108.3%	124.1%	133.7%	143.6%	148.3%	147.3%
Utilisation rates of RES-E technical potential, %	Hydro		na	na	na	na	na	na	na	85%
	Wind		na	na	na	na	na	na	na	88%
	Solar		na	na	na	na	na	na	na	51%
Utilisation rates of conventional power production, %	Coal and lignite		78.0%	78.0%	na	na	na	na	na	na
	Natural gas		na	na	na	na	na	na	na	na
	Nuclear		na	na	na	na	na	na	na	na
Natural gas consumption of power generation, TWh			–	–	–	–	–	–	–	–
Security of supply	Generation adequacy margin		65%	55%	67%	94%	106%	127%	144%	141%
	System adequacy margin		364%	421%	721%	706%	700%	718%	950%	870%
CO_2 emission	Emission, Mt CO_2		1.8	1.8	0	0	0	0	0	0
	CO_2 emission reduction compared to 1990, %		41.0%	41.0%	100%	100%	100%	100%	100%	100%
Spreads	Clean dark spread, €(2015)/MWh		25.4	31.9	42.4	14.1	11.7	17.9	1.9	-30.0
	Clean spark spread, €(2015)/MWh		-2.9	0.6	4.9	-5.9	-6.4	-1.7	-7.3	-27.2
Price impacts	Electricity wholesale price, €(2015)/MWh		34.7	42.1	52.4	59.5	66.7	81.7	85.8	74.2
	Total RES-E support/gross consumption, €(2015)/MWh, five year average		na	1.9	7.5	9.3	6.6	3.9	1.2	1.9
	Revenue from CO_2 auction/gross consumption, €(2015)/MWh		0	0	0	0	0	0	0	0
Investment cost, m€/5 year period	Coal and lignite		na	0	0	0	0	0	0	0
	Natural gas		na	0	0	0	0	0	0	0
	Total Fossil		na	0	0	0	0	0	0	0
	Total RES-E		na	142	949	500	294	669	950	403
	Total		na	142	949	500	294	669	950	403
Main assumptions	Coal price, €(2015)/GJ		1.8	2.0	1.9	1.9	2.0	2.0	2.0	2.0
	Lignite price, €(2015)/GJ		0.98	1.07	1.06	1.04	1.09	1.12	1.12	1.12
	Natural gas price, €(2015)/MWh		18.79	20.74	23.78	25.98	28.07	31.64	32.72	33.00
	CO_2 price, €(2015)/t		8.60	15.00	22.50	33.50	42.00	50.00	69.00	88.00

TABLE A4 | SENSITIVITY ANALYSIS – LOW CARBON PRICE

			2016	2020	2025	2030	2035	2040	2045	2050
Installed capacity, MW	Coal, lignite	Existing	219	219	0	0	0	0	0	0
		New	0	0	0	0	0	0	0	0
	Natural gas	Existing	0	0	0	0	0	0	0	0
		New	0	0	0	0	0	0	0	0
	Nuclear	Existing	0	0	0	0	0	0	0	0
		New	0	0	0	0	0	0	0	0
	HFO/LFO		0	0	0	0	0	0	0	0
	Hydro		668	671	915	1 146	1 371	1 459	1 592	1 648
	Wind		0	72	472	593	656	735	944	1 050
	Solar		3	12	59	165	343	537	557	651
	Other RES		0	0	4	4	4	5	5	6
Gross consumption, GWh			3 443	3 811	4 079	4 422	4 586	4 810	5 057	5 298
Net electricity generation, GWh	Total		3 997	4 154	4 396	5 601	6 739	7 421	8 278	8 738
	Coal and lignite		1 493	1 493	0	0	0	0	0	0
	Natural gas		0	0	0	0	0	0	0	0
	Nuclear		0	0	0	0	0	0	0	0
	HFO/LFO		0	0	0	0	0	0	0	0
	Hydro		2 499	2 511	3 421	4 288	5 127	5 459	5 919	6 101
	Wind		0	138	901	1 132	1 252	1 404	1 791	1 983
	Solar		5	12	59	166	345	540	548	633
	Other RES		0	0	15	15	15	19	20	22
Net import, GWh	Total		-554	-343	-317	-1 179	-2 153	-2 611	-3 221	-3 441
	BA_SRP		1 576	3 123	865	729	838	843	506	88
	KO		-68	725	-96	25	-422	-59	15	582
	RS		-119	2 111	-246	-22	-637	-3 124	-2 552	-3 349
	AL		-1 943	-2 214	-13	44	90	648	848	1 648
	IT		0	-4 088	-827	-1 955	-2 021	-920	-2 038	-2 409
Net import ratio, %			-16.1%	-9.0%	-7.8%	-26.7%	-46.9%	-54.3%	-63.7%	-64.9%
RES-E share (RES-E production/gross consumption, %)			72.7%	69.8%	107.8%	126.7%	146.9%	154.3%	163.7%	164.9%
Utilisation rates of RES-E technical potential, %	Hydro		na	na	na	na	na	na	na	95.0%
	Wind		na	na	na	na	na	na	na	98.7%
	Solar		na	na	na	na	na	na	na	67.2%
Utilisation rates of conventional power production, %	Coal and lignite		78.0%	78.0%	na	na	na	na	na	na
	Natural gas		na	na	na	na	na	na	na	na
	Nuclear		na	na	na	na	na	na	na	na
Natural gas consumption of power generation, TWh			0	0	0	0	0	0	0	0
Security of supply	Generation adequacy margin		65%	55%	68%	97%	127%	142%	166%	168%
	System adequacy margin		364%	421%	721%	709%	721%	734%	970%	881%
CO_2 emission	Emission, Mt CO_2		1.8	1.8	0	0	0	0	0	0
	CO_2 emission reduction compared to 1990, %		41.0%	41.0%	100%	100%	100%	100%	100%	100%
Spreads	Clean dark spread, €(2015)/MWh		22.5	28.4	36.4	3.3	-1.4	7.8	-15.6	-54.3
	Clean spark spread, €(2015)/MWh		-5.8	-3.0	-1.1	-16.7	-19.5	-11.8	-24.8	-51.5
Price impacts	Electricity wholesale price, €(2015)/MWh		31.8	38.5	46.5	48.7	53.5	71.6	68.4	49.9
	Total RES-E support/gross consumption, €(2015)/MWh, five year average		na	1.8	24.0	25.7	28.7	28.2	29.1	49.8
	Revenue from CO_2 auction/gross consumption, €(2015)/MWh		0	0	0	0	0	0	0	0
Investment cost, m€/5 year period	Coal and lignite		na	0	0	0	0	0	0	0
	Natural gas		na	0	0	0	0	0	0	0
	Total Fossil		na	0	0	0	0	0	0	0
	Total RES-E		na	117	941	603	626	519	987	452
	Total		na	117	941	603	626	519	987	452
Main assumptions	Coal price, €(2015)/GJ		1.78	1.95	1.93	1.89	1.98	2.04	2.04	2.04
	Lignite price, €(2015)/GJ		0.98	1.07	1.06	1.04	1.09	1.12	1.12	1.12
	Natural gas price, €(2015)/MWh		18.79	20.74	23.78	25.98	28.07	31.64	32.72	33.00
	CO_2 price, €(2015)/t		4.30	7.50	11.25	16.75	21.00	25.00	34.50	44.00

TABLE A5 | SENSITIVITY ANALYSIS – LOW DEMAND

			2016	2020	2025	2030	2035	2040	2045	2050
Installed capacity, MW	Coal, lignite	Existing	219	219	0	0	0	0	0	0
		New	0	0	0	0	0	0	0	0
	Natural gas	Existing	0	0	0	0	0	0	0	0
		New	0	0	0	0	0	0	0	0
	Nuclear	Existing	0	0	0	0	0	0	0	0
		New	0	0	0	0	0	0	0	0
	HFO/LFO		0	0	0	0	0	0	0	0
	Hydro		668	671	868	952	1 079	1 180	1 420	1 450
	Wind		0	80	464	478	494	570	734	748
	Solar		3	12	47	85	205	373	463	524
	Other RES		0	0	1	1	1	1	1	3
Gross consumption, GWh			3 440	3 770	3 981	4 256	4 353	4 508	4 687	4 831
Net electricity generation, GWh	Total		3 997	4 169	4 182	4 561	5 188	5 877	7 149	7 354
	Coal and lignite		1 493	1 493	0	0	0	0	0	0
	Natural gas		0	0	0	0	0	0	0	0
	Nuclear		0	0	0	0	0	0	0	0
	HFO/LFO		0	0	0	0	0	0	0	0
	Hydro		2 499	2 511	3 247	3 560	4 037	4 412	5 290	5 403
	Wind		0	153	885	912	943	1 087	1 394	1 420
	Solar		5	12	47	85	206	375	459	519
	Other RES		0	0	2	2	2	2	5	11
Net import, GWh	Total		-557	-399	-200	-304	-836	-1 369	-2 463	-2 523
	BA_SRP		1 842	2 361	774	1 599	56	922	-353	-848
	KO		-164	545	106	-19	-408	-600	-403	-827
	RS		-364	2 015	2 208	1 565	-3 161	-4 463	-5 269	-7 431
	AL		-1 870	-1 125	441	-342	-973	5	-482	-488
	IT		0	-4 196	-3 729	-3 106	3 651	2 767	4 043	7 071
Net import ratio, %			-16.2%	-10.6%	-5.0%	-7.1%	-19.2%	-30.4%	-52.5%	-52.2%
RES-E share (RES-E production/gross consumption, %)			72.8%	71.0%	105.0%	107.1%	119.2%	130.4%	152.5%	152.2%
Utilisation rates of RES-E technical potential, %	Hydro		na	na	na	na	na	na	na	83.6%
	Wind		na	na	na	na	na	na	na	70.3%
	Solar		na	na	na	na	na	na	na	54.1%
Utilisation rates of conventional power production, %	Coal and lignite		78.0%	78.0%	na	na	na	na	na	na
	Natural gas		na	na	na	na	na	na	na	na
	Nuclear		na	na	na	na	na	na	na	na
Natural gas consumption of power generation, TWh			0	0	0	0	0	0	0	0
Security of supply	Generation adequacy margin		65%	56%	62%	68%	85%	105%	151%	149%
	System adequacy margin		364%	425%	728%	697%	702%	725%	1 014%	934%
CO_2 emission	Emission, Mt CO_2		1.8	1.8	0	0	0	0	0	0
	CO_2 emission reduction compared to 1990, %		41.0%	41.0%	100%	100%	100%	100%	100%	100%
Spreads	Clean dark spread, €(2015)/MWh		25.4	31.6	42.3	14.6	15.3	25.2	-3.1	-29.4
	Clean spark spread, €(2015)/MWh		-2.9	0.3	4.8	-5.4	-2.8	5.6	-12.3	-26.6
Price impacts	Electricity wholesale price, €(2015)/MWh		34.7	41.8	52.4	60.0	70.2	89.0	80.8	74.7
	Total RES-E support/gross consumption, €(2015)/MWh, five year average		na	1.8	13.3	5.5	4.8	0.8	0	0
	Revenue from CO_2 auction/gross consumption, €(2015)/MWh		0	0	0	0	0	0	0	0
Investment cost, m€/5 year period	Coal and lignite		na	0	0	0	0	0	0	0
	Natural gas		na	0	0	0	0	0	0	0
	Total Fossil		na	0	0	0	0	0	0	0
	Total RES-E		na	128	821	185	300	483	1 126	154
	Total		na	128	821	185	300	483	1 126	154
Main assumptions	Coal price, €(2015)/GJ		1.8	2.0	1.9	1.9	2.0	2.0	2.0	2.0
	Lignite price, €(2015)/GJ		0.98	1.07	1.06	1.04	1.09	1.12	1.12	1.12
	Natural gas price, €(2015)/MWh		18.79	20.74	23.78	25.98	28.07	31.64	32.72	33.00
	CO_2 price, €(2015)/t		8.60	15.00	22.50	33.50	42.00	50.00	69.00	88.00

TABLE A6 | SENSITIVITY ANALYSIS – HIGH DEMAND

			2016	2020	2025	2030	2035	2040	2045	2050
Installed capacity, MW	Coal, lignite	Existing	219	219	0	0	0	0	0	0
		New	0	0	0	0	0	0	0	0
	Natural gas	Existing	0	0	0	0	0	0	0	0
		New	0	0	0	0	100	100	100	100
	Nuclear	Existing	0	0	0	0	0	0	0	0
		New	0	0	0	0	0	0	0	0
	HFO/LFO		0	0	0	0	0	0	0	0
	Hydro		668	671	915	1 146	1 378	1 459	1 592	1 648
	Wind		0	80	486	569	663	771	933	1 044
	Solar		3	12	59	165	345	582	606	655
	Other RES		0	0	4	4	4	5	5	6
Gross consumption, GWh			3 440	3 845	4 164	4 566	4 792	5 096	5 417	5 731
Net electricity generation, GWh	Total		3 997	4 169	4 423	5 555	7 290	7 962	8 708	8 958
	Coal and lignite		1 493	1 493	0	0	0	0	0	0
	Natural gas		0	0	0	0	508	428	391	182
	Nuclear		0	0	0	0	0	0	0	0
	HFO/LFO		0	0	0	0	0	0	0	0
	Hydro		2 499	2 511	3 421	4 288	5 154	5 459	5 926	6 128
	Wind		0	153	928	1 086	1 266	1 472	1 772	1 980
	Solar		5	12	59	166	347	586	599	645
	Other RES		0	0	15	15	15	18	20	23
Net import, GWh	Total		-557	-324	-259	-989	-2 498	-2 866	-3 291	-3 227
	BA_SRP		1 486	1 837	1 068	1 196	580	1 103	-528	55
	KO		-20	598	-264	-256	-382	-120	-17	235
	RS		116	1 957	634	-1 094	-4 449	-2 398	-3 040	-3 256
	AL		-2 139	-691	-18	-27	319	138	632	912
	IT		0	-4 025	-1 679	-808	1 433	-1 588	-337	-1 173
Net import ratio, %			-16.2%	-8.4%	-6.2%	-21.7%	-52.1%	-56.2%	-60.8%	-56.3%
RES-E share (RES-E production/gross consumption, %)			72.8%	69.6%	106.2%	121.7%	141.5%	147.8%	153.5%	153.1%
Utilisation rates of RES-E technical potential, %	Hydro		na	na	na	na	na	na	na	95.0%
	Wind		na	na	na	na	na	na	na	98.1%
	Solar		na	na	na	na	na	na	na	67.5%
Utilisation rates of conventional power production, %	Coal and lignite		78.0%	78.0%	na	na	na	na	na	na
	Natural gas		na	na	na	na	58.0%	48.8%	44.7%	20.8%
	Nuclear		na	na	na	na	na	na	na	na
Natural gas consumption of power generation, TWh			0	0	0	0	0.9	0.7	0.7	0.3
Security of supply	Generation adequacy margin		65%	54%	65%	91%	133%	145%	164%	158%
	System adequacy margin		364%	417%	707%	686%	704%	708%	910%	818%
CO_2 emission	Emission, Mt CO_2		1.8	1.8	0	0	0.2	0.1	0.1	0.1
	CO_2 emission reduction compared to 1990, %		41.0%	41.0%	100%	100%	94.1%	95.1%	95.5%	97.9%
Spreads	Clean dark spread, €(2015)/MWh		25.4	32.3	42.6	49.6	56.2	69.3	71.2	61.3
	Clean spark spread, €(2015)/MWh		-2.9	1.0	5.1	7.5	10.3	16.7	16.4	5.9
Price impacts	Electricity wholesale price, €(2015)/MWh		34.7	42.4	52.7	59.5	66.5	80.0	81.9	71.9
	Total RES-E support/gross consumption, €(2015)/MWh, five year average		na	1.8	23.9	20.0	19.7	16.8	13.7	28.9
	Revenue from CO_2 auction/gross consumption, €(2015)/MWh		0	0	0	0	1.5	1.5	1.7	1.0
Investment cost, m€/5 year period	Coal and lignite		na	0	0	0	0	0	0	0
	Natural gas		na	0	0	0	0	0	0	0
	Total Fossil		na	0	0	0	0	0	0	0
	Total RES-E		na	128	949	553	682	577	940	393
	Total		na	128	949	553	682	577	940	393
Main assumptions	Coal price, €(2015)/GJ		1.8	2.0	1.9	1.9	2.0	2.0	2.0	2.0
	Lignite price, €(2015)/GJ		0.98	1.07	1.06	1.04	1.09	1.12	1.12	1.12
	Natural gas price, €(2015)/MWh		18.79	20.74	23.78	25.98	28.07	31.64	32.72	33.00
	CO_2 price, €(2015)/t		8.60	15.00	22.50	33.50	42.00	50.00	69.00	88.00

TABLE A7 | SENSITIVITY ANALYSIS – LOW RENEWABLE POTENTIAL

			2016	2020	2025	2030	2035	2040	2045	2050
Installed capacity, MW	Coal, lignite	Existing	219	219	0	0	0	0	0	0
		New	0	0	0	0	0	0	0	0
	Natural gas	Existing	0	0	0	0	0	0	0	0
		New	0	0	0	0	0	0	0	0
	Nuclear	Existing	0	0	0	0	0	0	0	0
		New	0	0	0	0	0	0	0	0
	HFO/LFO		0	0	0	0	0	0	0	0
	Hydro		668	671	897	930	1 047	1 083	1 206	1 206
	Wind		0	45	276	303	332	378	467	480
	Solar		3	12	65	196	414	556	725	928
	Other RES		0	0	4	4	4	5	5	13
Gross consumption, GWh			3 440	3 807	4 072	4 408	4 569	4 797	5 034	5 261
Net electricity generation, GWh	Total		4 000	4 102	3 963	4 270	4 983	5 348	6 135	6 372
	Coal and lignite		1 493	1 493	0	0	0	0	0	0
	Natural gas		0	0	0	0	0	0	0	0
	Nuclear		0	0	0	0	0	0	0	0
	HFO/LFO		0	0	0	0	0	0	0	0
	Hydro		2 499	2 511	3 356	3 480	3 918	4 050	4 501	4 491
	Wind		4	86	526	578	634	721	890	911
	Solar		5	12	66	197	417	559	723	919
	Other RES		0	0	15	15	15	18	21	51
Net import, GWh	Total		-560	-295	109	138	-414	-551	-1 101	-1 111
	BA_SRP		1 871	2 131	723	1 104	280	897	-697	-1 295
	KO		-225	990	334	-294	-388	-223	-453	-495
	RS		-339	1 489	1 851	849	-2 651	-1 051	-1 840	-6 574
	AL		-1 868	-749	824	478	495	374	419	-500
	IT		0	-4 157	-3 623	-1 999	1 849	-547	1 469	7 754
Net import ratio, %			-16.3%	-7.8%	2.7%	3.1%	-9.1%	-11.5%	-21.9%	-21.1%
RES-E share (RES-E production/gross consumption, %)			72.9%	68.5%	97.3%	96.9%	109.1%	111.5%	121.9%	121.1%
Utilisation rates of RES-E technical potential, %	Hydro		na	na	na	na	na	na	na	69.5%
	Wind		na	na	na	na	na	na	na	45.1%
	Solar		na	na	na	na	na	na	na	95.8%
Utilisation rates of conventional power production, %	Coal and lignite		78.0%	78.0%	na	na	na	na	na	na
	Natural gas		na	na	na	na	na	na	na	na
	Nuclear		na	na	na	na	na	na	na	na
Natural gas consumption of power generation, TWh			0	0	0	0	0	0	0	0
Security of supply	Generation adequacy margin		65%	54%	60%	56%	70%	76%	98%	97%
	System adequacy margin		364%	420%	713%	668%	663%	667%	901%	808%
CO_2 emission	Emission, Mt CO_2		1.8	1.8	0	0	0	0	0	0
	CO_2 emission reduction compared to 1990, %		41.0%	41.0%	100%	100%	100%	100%	100%	100%
Spreads	Clean dark spread, €(2015)/MWh		25.4	32.0	42.4	49.8	56.4	71.1	73.7	63.6
	Clean spark spread, €(2015)/MWh		-2.9	0.7	4.9	7.6	10.6	18.4	18.9	8.3
Price impacts	Electricity wholesale price, €(2015)/MWh		34.7	42.2	52.5	59.6	66.8	81.7	84.3	74.2
	Total RES-E support/gross consumption, €(2015)/MWh, five year average		na	1.2	18.1	10.1	9.9	9.4	11.6	82.9
	Revenue from CO_2 auction/gross consumption, €(2015)/MWh		0	0	0	0	0	0	0	0
Investment cost, m€/5 year period	Coal and lignite		na	0	0	0	0	0	0	0
	Natural gas		na	0	0	0	0	0	0	0
	Total Fossil		na	0	0	0	0	0	0	0
	Total RES-E		na	79	708	206	446	278	736	224
	Total		na	79	708	206	446	278	736	224
Main assumptions	Coal price, €(2015)/GJ		1.8	2.0	1.9	1.9	2.0	2.0	2.0	2.0
	Lignite price, €(2015)/GJ		0.98	1.07	1.06	1.04	1.09	1.12	1.12	1.12
	Natural gas price, €(2015)/MWh		18.79	20.74	23.78	25.98	28.07	31.64	32.72	33.00
	CO_2 price, €(2015)/t		8.60	15.00	22.50	33.50	42.00	50.00	69.00	88.00

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

Capital expenditures	No target 2016-2050	Delayed 2016-2050	Decarbon 2016-2050
Biogas	1	3	40
Solid biomass	4	6	190
Biowaste	0	0	0
Geothermal ele.	0	0	0
Hydro large-scale	889	1 358	1 151
Hydro small-scale	91	211	214
Central PV	30	187	226
Decentralised PV	194	374	357
CSP	0	0	0
Wind onshore	924	1 713	1 727
Wind offshore	0	0	0
RES-E total	2 133	3 853	3 906

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

Support expenditures in M€	2016-2020	2021-2025	2026-2030	2031-2035	2036-2040	2041-2045	2046-2050	Total
No target	**40**	**53**	**27**	**1**	**–**	**–**	**–**	**120**
Central PV	–	–	–	–	–	–	–	–
Decentralised PV	3	3	1	0	–	–	–	8
Wind onshore	31	45	25	1	–	–	–	102
Delayed	**40**	**214**	**48**	**42**	**108**	**174**	**1 007**	**1 633**
Central PV	–	3	0	1	2	6	58	69
Decentralised PV	3	6	2	2	11	18	95	137
Wind onshore	31	129	36	21	49	76	402	744
Decarbon	**39**	**168**	**200**	**150**	**93**	**30**	**50**	**729**
Central PV	–	4	6	6	6	7	35	64
Decentralised PV	3	5	6	7	3	0	7	31
Wind onshore	30	155	188	137	84	16	9	619

Annex 2 | Assumptions

Assumed technology investment cost trajectories: RES and fossil

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

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

Source: Green-X database

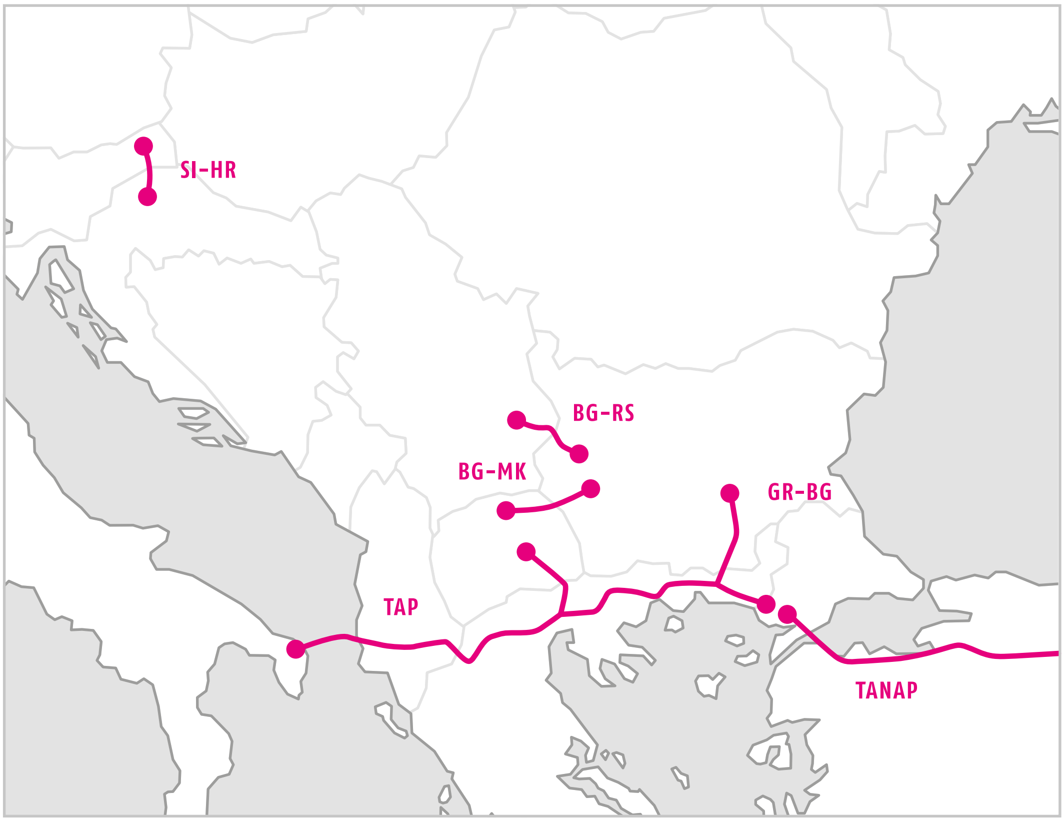
Infrastructure (table for the whole region)

TABLE A11 | NEW GAS INFRASTRUCTURE IN THE REGION

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

Source: ENTSO-G TYNDP

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



Source: ENTSO-G TYNDP 2017

TABLE A12 | CROSS BORDER TRANSMISSION NETWORK CAPACITIES

From	To	Year of commissioning	Capacity, MW O → D	Capacity, MW D → O
ME	IT	2019	500	500
ME	IT	2023	700	700
ME	RS	2025	400	600
RS	ME	2025	500	500
IT	ME	2045	2 000	2 000

Source: ENTSO-E TYNDP 2017

Generation units and their inclusion in the core scenarios

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

Unit name	Installed capacity [MW]	Expected year of commissioning	Expected year of decommissioning	Fuel type	Type	CCS	No target	Delay	De-carbon
TPP Plevlja	218.5	1982	2023	lignite	thermal	no	yes	yes	yes
TPP Plevlja 2	250.0	2024	2075	lignite	thermal	no	yes	yes	no

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