SEERMAP

South East Europe Electricity Roadmap

SOUTH EAST EUROPE ELECTRICITY ROADMAP

Country report

Albania

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

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SEERMAP
South East Europe Electricity Roadmap

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**

MINISTERIUM FÜR EIN LEBENSWERTES ÖSTERREICH

European Climate Foundation

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

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

REKK FOUNDATION

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

TU WIEN TECHNISCHE UNIVERSITÄT WIEN

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

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ekc

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

OGResearch

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

ERRA ENERGY REGULATORS REGIONAL ASSOCIATION

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

Local partners in SEERMAP target countries

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

Co-PLAN (Albania) is a non-profit organization, its research and consultative work builds upon four expertise areas: namely Spatial Planning and Land Development, Urban and Regional Governance, Urban Environmental Management, with cross-cutting research.

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

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

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

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

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

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

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

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.

Albania is set to embark on a balanced, albeit slow development path leading to an energy mix based almost exclusively on RES capacities by 2050. Hydro capacities are likely to dominate the generation fleet throughout the projected period, but Albania will gradually exploit its wind potential as well. Most of the new capacities are expected to be deployed after 2030, with the exception of photovoltaic developments, as recent government plans aim to exploit 50 MWp installed solar capacity till 2020.

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 Albania can take:

- Albania is expected to meet the overall decarbonisation target for the EU28+Western Balkans region even in the 'no target' scenario, which gives the country room to evaluate a number of policy options, in particular the role of natural gas in the energy mix.

- A maximum of 460 MW gas-fired capacity is projected in the 'no target' scenario, with the share of natural gas in the electricity mix peaking in 2030 with 31% of electricity production and declining to just 4% by 2050. By contrast, in the 'decarbonisation' scenario the share of gas in the electricity mix never surpasses 5%.
- If Albania chooses to actively support RES technologies, a long term effort appears more advantageous than delayed action. First, the 'decarbonisation' scenario leads to significantly lower stranded costs related to natural gas generation assets. Second, if action is delayed, the disproportionate effort needed towards the end of the modelled period to reach the CO_2 emission reduction target requires a significant increase in RES support.
- The country is likely to become a net electricity exporter by 2030 in all scenarios. Its system adequacy margin is positive throughout the entire period, while installed generation capacity within the country enables Albania to satisfy domestic demand in all hours of the year using domestic generation from around 2040.
- Compared to a scenario with no emission reduction target, decarbonisation policies do not drive up wholesale electricity prices. The price of electricity follows a similar trajectory under all scenarios and only diverges after 2045, when prices are lower in scenarios with more 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 is observable across the entire SEE region – and in fact the EU as a whole –in all scenarios for the modelled time period, driven by the increasing price of carbon and natural gas. Despite higher absolute wholesale prices, household expenditure on electricity as a share of disposable income increases only slightly in all scenarios according to the macroeconomic analysis, and decreases to current levels by 2050 in the 'decarbonisation' scenario. Furthermore, the positive implication of higher wholesale prices is that investment in electricity generation becomes more attractive to investors, addressing the current underinvestment in the sector.
- Policies aiming at a higher level of decarbonisation – delayed or not – will require a significant increase in investment in generation capacity. These investments are assumed to be financed by private actors who accept higher investment costs in exchange for lower operation (including fuel) and maintenance costs when making their investment decisions. From a social point of view, the high level of investment has a positive impact on GDP as well as on the current account and external balance. This latter effect is a result of higher net electricity exports enabled by greater RES-based generation and lower imports of natural gas.
- Transmission network investments needs remain below 100 mEUR in the decarbonisation scenarios compared to the reference network development based on the ENTSO-E TYNDP. This is low in comparison to investment needed in generation capacity.

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; 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 utilised with the help of policies eliminating barriers to RES investment. De-risking policies that reduce high financing and high capital costs are especially relevant in the region including Albania, 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 include increased GDP as a result of increased investment in generation capacity, an improved external balance due to higher net electricity exports, and lower wholesale electricity prices over the long term which can result from high penetration of RES. Additional co-benefits include health and environmental benefits from reduced emissions to air, however, these benefits are not addressed in this report.
- Policy makers need to address the trade-offs which characterise fossil fuel investments. Gas based capacities are expected to be priced out of the market before the end of their lifetime in all scenarios; the resulting stranded costs are lowest in the 'decarbonisation' scenario.
- Regional level planning improves system adequacy compared with national plans emphasizing reliance on domestic 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 (Central and South Eastern Europe Gas Connectivity) 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*, 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 Albania. 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

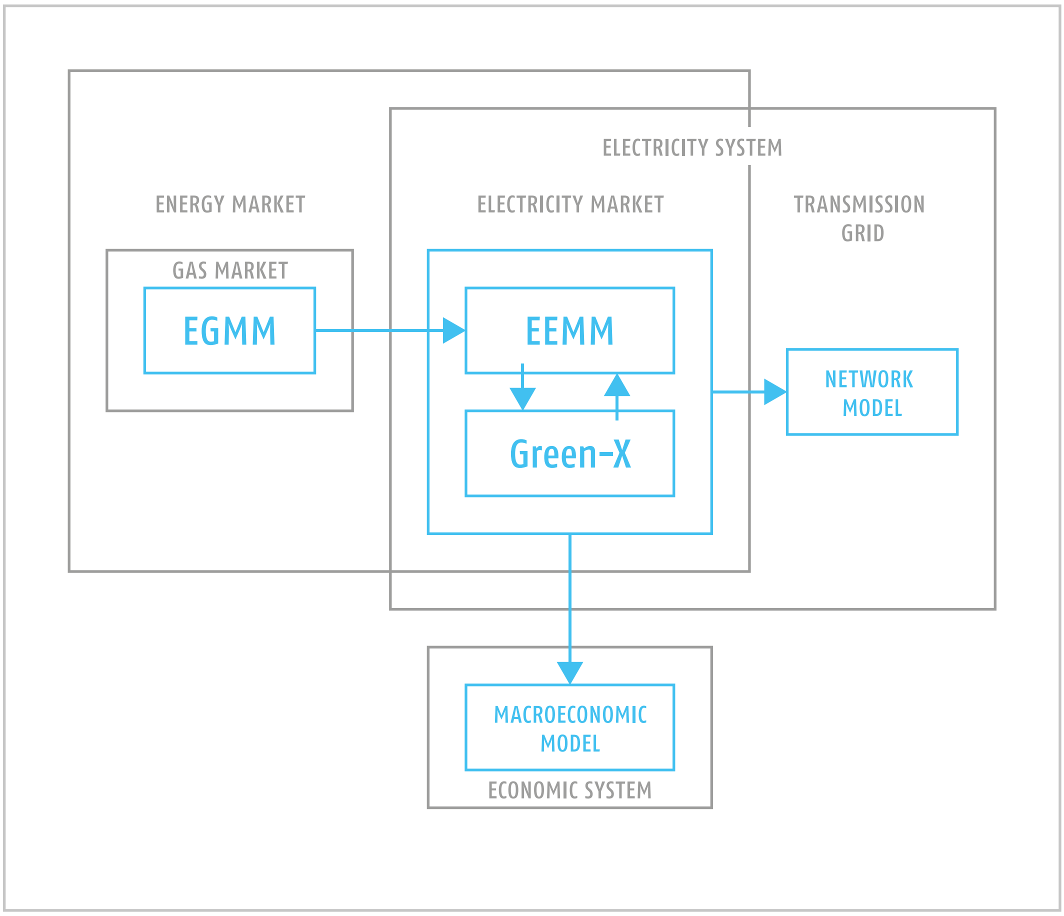
Electricity sector futures are explored using a set of five high resolution models incorporating the crucial factors which influence electricity policy and investment decisions. The European Electricity Market Model (EEMM) and the Green-X model together assess the impact of different scenario assumptions 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, 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

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")



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.

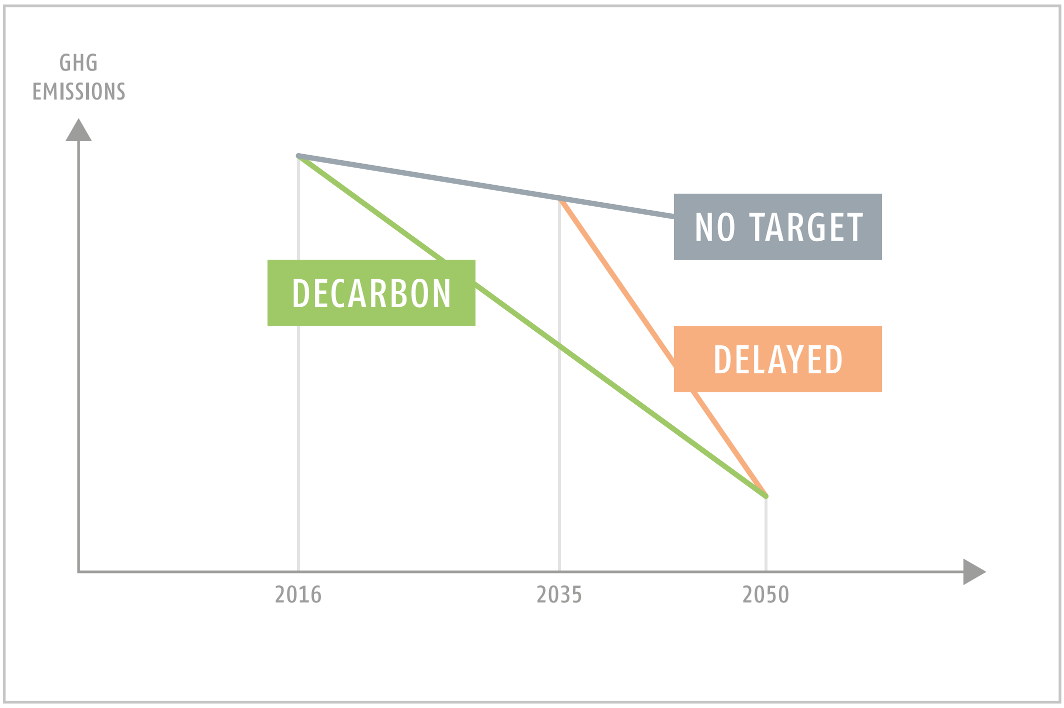
The modelling work does not take into account the impacts of the new Large Combustion Plant BREF (Commission Implementing Decision of 2017/1442), as it entered into force in July 2017, when SEERMAP modelling part was already finalised.

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

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

- In the 'no target' scenario all currently planned fossil fuel power plants are entered into the model exogenously. Information on planned power plants is taken from official national strategies/plans and information received from the local partners involved in the project. We have assumed the continuation of current renewable support policies up to 2020 and the gradual phasing out of support between 2021 and 2025. The scenario assumes countries meet their 2020 renewable target but do not set a CO_2 emission reduction target for 2050. Although a CO_2 target is not imposed, producers face CO_2 prices in this scenario, as well as in the others.
- In the 'decarbonisation' scenario, only those planned investments which had a final investment decision in 2016 were considered, resulting in lower exogenous fossil fuel

FIGURE 2
THE CORE SCENARIOS



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 Albania, demand figures indicating an average annual growth rate of 1.3% between 2015 and 2050 were provided by our local partner.

- Demand side management (DSM) measures were assumed to shift 3.5% of total daily demand from peak load to base load hours by 2050. The 3.5% assumption is a conservative estimate compared to other projections from McKinsey (2010) or TECHNOFI (2013). No demand side measures were assumed to be implemented before 2035.

Factors affecting the cost of investment and generation:

- Fossil fuel prices: Gas prices are derived from the EGMM model. The price of oil and coal were taken from IEA (2016) and EIA (2017) respectively. The price of both oil and coal is expected to increase by approximately 15% by 2050 compared with 2016. The gas price is differentiated by country, the increase in the price of gas in Albania according to the EGMM is between 69% between 2020 and 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 Albania was assumed to be 12% in 2015, decreasing to 10.7% by 2050. Other studies also estimated WACC values for the region and confirm that values are high.
- 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 II) 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

Albania is set to embark on a an electricity sector development path that will lead to an energy mix based almost exclusively on RES capacities by 2050. The potentially smooth expansion of its RES-based capacities is facilitated by a starting point where Albania has no fossil-based capacity at all; in 2015, 1800 MW of hydro capacity was supplemented by 2 MW of solar and 5 MW of other RES. Hydro capacities are likely to dominate its generation fleet throughout the modelled time period, but Albania will gradually exploit its wind and solar potential as well. In the 'decarbonisation' scenario, total installed capacity may increase 4-fold between 2020 and 2050, with the shares of hydro, wind, and solar at 49%, 23%, and 27%, respectively by 2050. Most of the new capacities are expected to be deployed after 2030.

Albania is facing a policy choice regarding the role of natural gas. In the 'no target' and 'delayed' scenarios, gas-fired capacities enter into production early in the

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

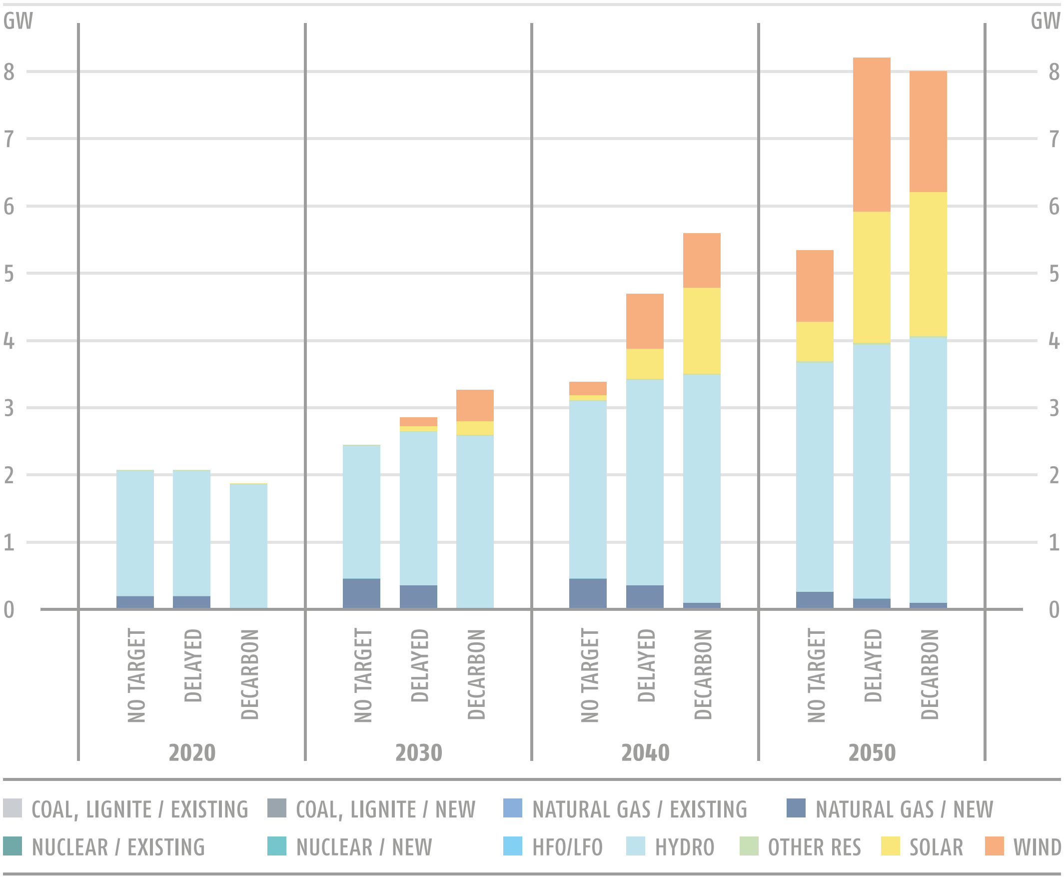


FIGURE 4
ELECTRICITY GENERATION AND DEMAND (TWh) AND RES SHARE (% OF DEMAND) IN ALBANIA, 2020-2050

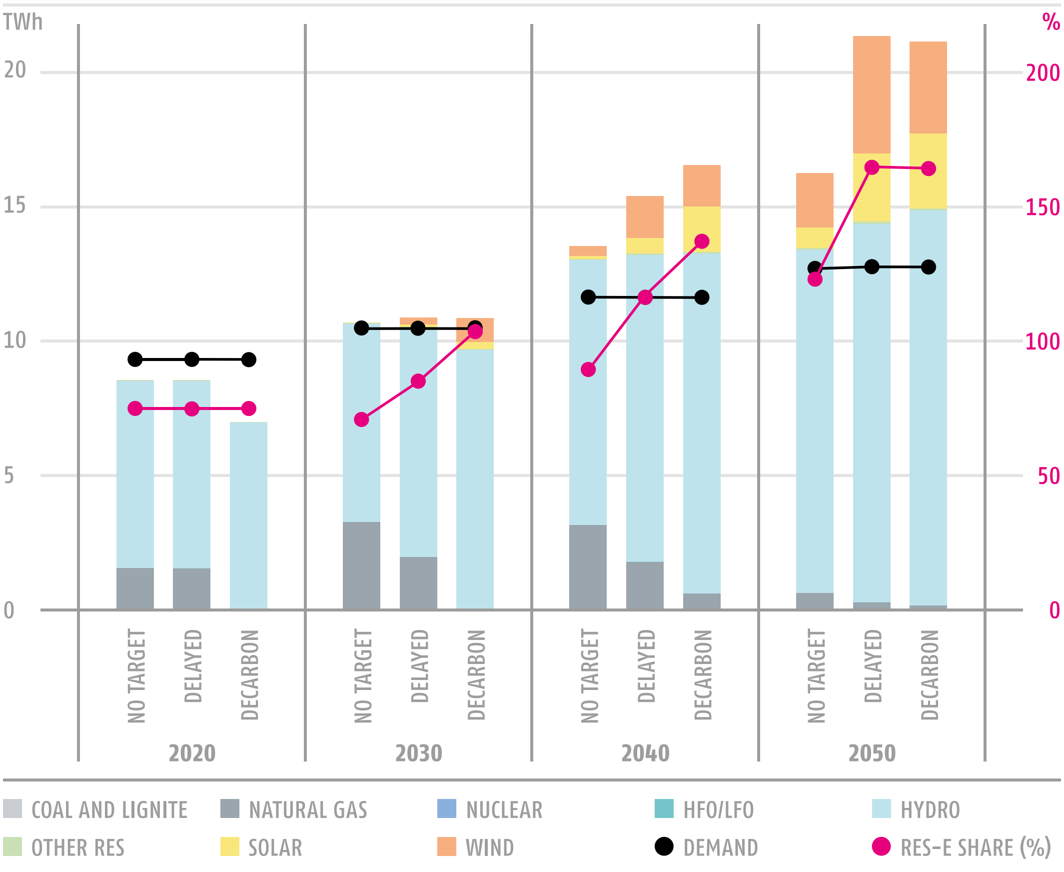
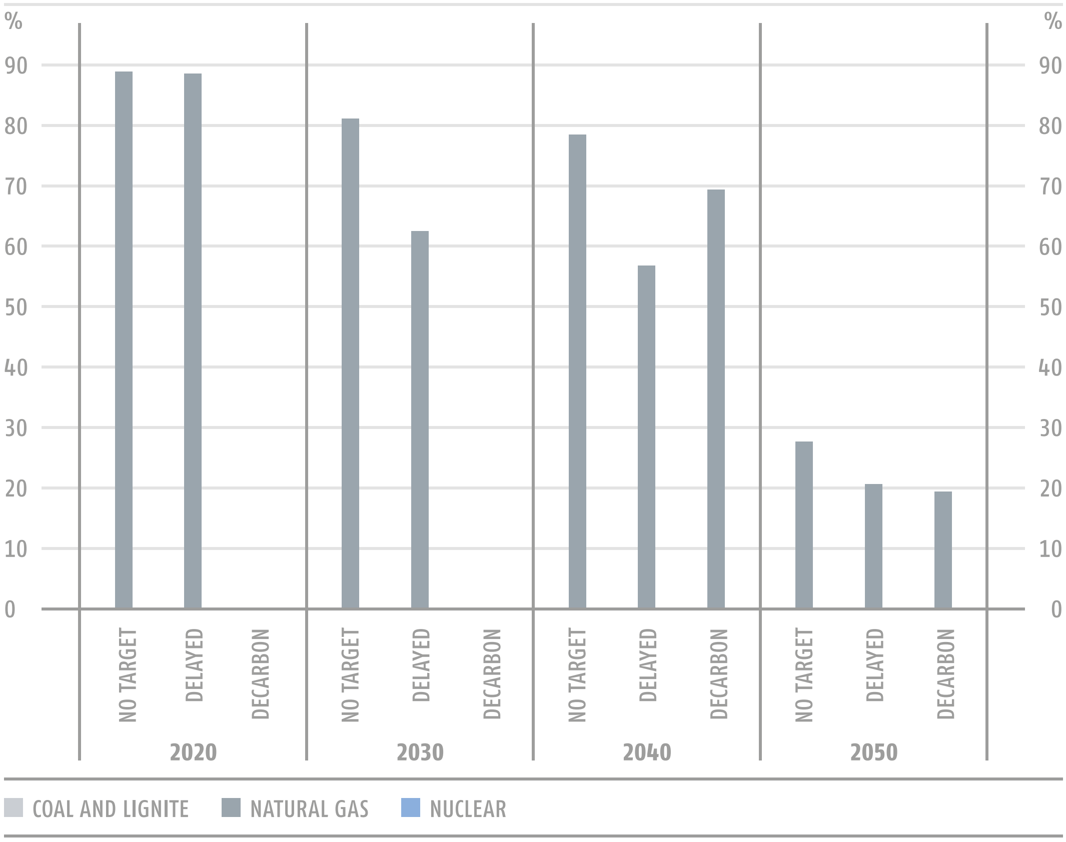


FIGURE 5
UTILISATION RATES OF CONVENTIONAL GENERATION IN ALBANIA, 2020-2050 (%)



modelled period. A maximum of 460 MW gas-fired capacity is projected in the 'no target' scenario between 2030 and 2045, with generation likely peaking in 2030 at 31% of electricity production and declining to just 4% by 2050. Natural gas based electricity generation decreases over the second half of the modelled time horizon due to an increase in both the price of carbon and natural gas. In the 'decarbonisation' scenario, only 100 MW of gas-fired capacity is deployed by 2035; its share in the electricity mix never surpasses 5% and falls to only 1% in 2050.

With expanding production capacities, Albania is projected to become a net electricity exporter by 2030 in all scenarios. A 15% higher level of hydro capacity, as well as accelerrating deployment of wind and solar capacities after 2030 in the 'delayed' and 'decarbonisation' scenarios leads to 30% more electricity generation in 2050 compared to the 'no target' scenario, resulting in an even stronger position as a net electricity exporter. As gas-fired generation becomes insignificant by 2050, even in the 'no target' scenario Albania reaches a minimum of 123% of RES-share if compared to consumption, potentially moving up to 165% in the 'delayed' and 'decarbonisation' scenarios.

The policy choice favouring the early installation of gas-fired capacities might be supported by the expectation of high utilisation rates until 2040, especially in the 'no target' scenario where utilisation is projected at 67.5% even in 2045. In the 'decarbonisation' scenario, however, gas-fired capacities entering the electricity generation mix between 2030 and 2035 have utilisation rates above 50% for only 10-15 years; as a result these investments will be stranded. This issue is discussed further in section 5.4. The rapid decline of utilisation rates after 2040 is a combined effect of rising natural gas and carbon allowance 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 Albania, the generation adequacy margin turns positive around 2040 in all scenarios, later than when the country is expected to become a net exporter (See Figure 6). This is beacuse a margin is required to ensure that domestic generation capacity is sufficient to satisfy domestic demand in all modelled hours of the year. The system adequacy margin, however, is positive for all hours of all years shown.

In addition to the adequacy margin indicators, the cost of increasing the generation adequacy margin to zero was calculated for countries with initially negative values. The cost of the required capacity was defined as the yearly fixed cost of an open cycle gas turbine (OCGT) which has the capacity to ensure that the generation adequacy margin reaches zero. By 2040 the generation adequacy margin becomes positive in all scenarios, but prior to that time the cost of increasing generation adequacy is highest in the ‘decarbonisation’ scenario.

5.3 Sustainability

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

The 94% overall decarbonisation target for the EU28+Western Balkans region translates into a higher than average level of decarbonisation in the Albanian electricity sector. Even with more gas-fired capacities deployed in the ‘no target’ and ‘delayed’ scenarios, by 2050 CO_2 emissions in the electricity sector compared with 1990 are reduced by 95% and 97.7% in these two scenarios, respectively. In the ‘decarbonisation’ scenario, emission reduction reaches 98.7% (See Figure 7). This is due to a relative advantage for renewable electricity production in Albania, and to the fact that it has a very advantageous low carbon starting position in 2016.

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

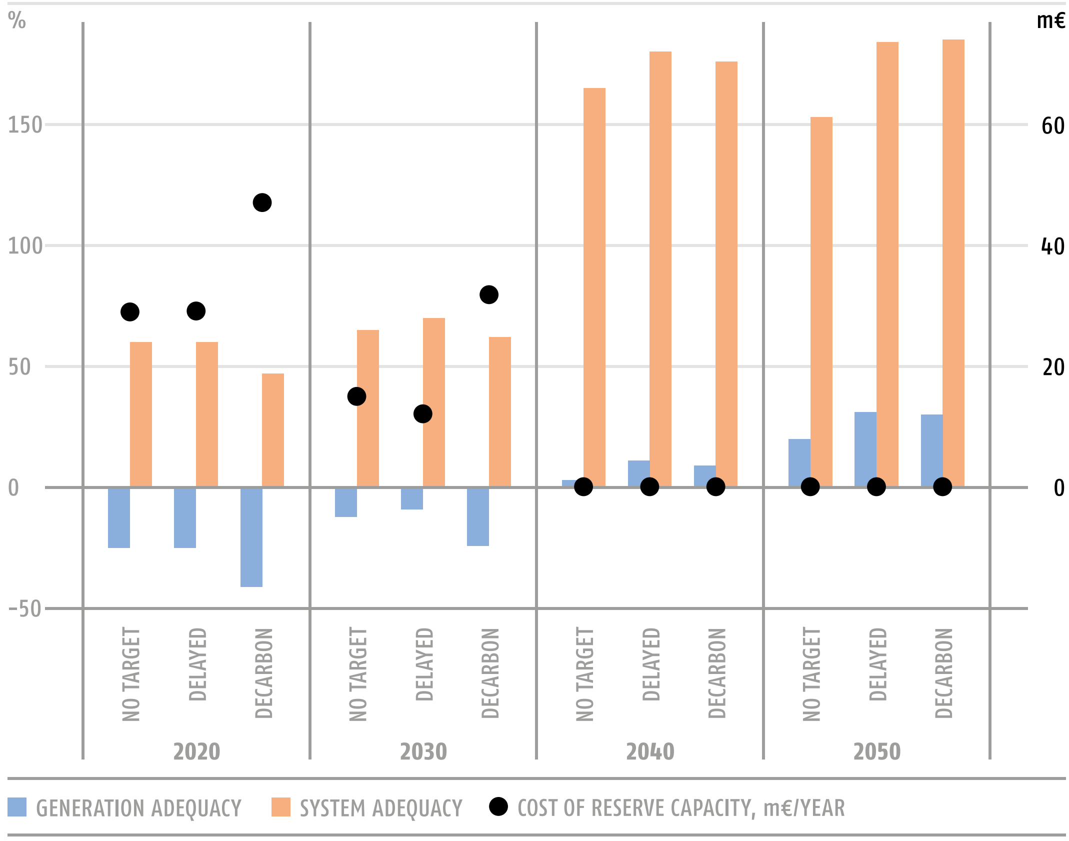


FIGURE 7
CO_2 EMISSIONS UNDER THE 3 CORE SCENARIOS IN ALBANIA, 2020-2050 (mt)

The share of renewable generation as a percentage of gross domestic consumption in the 'no target' scenario is 70.9% in 2030 and 123.1% in 2050. In both the 'delayed' and 'decarbonisation' scenarios the share of renewable generation is around 165% in 2050. The utilisation of RES technical potential is highest in the' delayed' scenario in 2050, at 88% for hydro, 95% for wind and 61% for solar. In the 'decarbonisation' scenario, utilisation of wind potential is significantly lower (74%). Recent government plans in Albania aim to exploit 50 MWp installed solar plant till 2020. This information was not included in the modelling as it was finalised before the information was made public.

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 in Albania is 2.9% in the 'no target' scenario and 2.2% and 2.3% respectively, in the 'delayed' and 'decarbonisation' scenarios. The lower growth in the latter two secnarios is due to a fall in wholesale prices over 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 only slightly even with the significant increase in wholesale electricity prices. 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 required for new capacities increases significantly over the entire modelled time period, particularly in the 'delayed' and 'decarbonisation' scenarios between 2040 and 2050, reflecting the significant effort needed to meet decarbonisation targets at the end of the period. It is lowest in the 'no target' scenario, except for the 2016-2020 period when 200 MW of gas-fired capacities are expected to be deployed.

Investments are assumed to be financed by private actors based on a profitability requirement (apart from the capacities planned in the national strategies), factoring 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 the overall investment level are limited to the impact on GDP and an improvement in the external balance and debt. These impacts are discussed in more detail in section 5.7.

Despite the significant investment needs associated with the 'decarbonisation' scenario, the renewables support needed to incentivise these investments remains low throughout the entire period, initially at 0.1 EUR/MWh, rising to 4.3 EUR/MWh by the end of the modelled time horizon. The RES support relative to electricity cost (wholesale price plus RES support) rises only to 5.4% between 2045 and 2050 in the 'decarbonisation' scenario. In the 'delayed' scenario, however, the rapid deployment of additional capacities towards the end of the

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

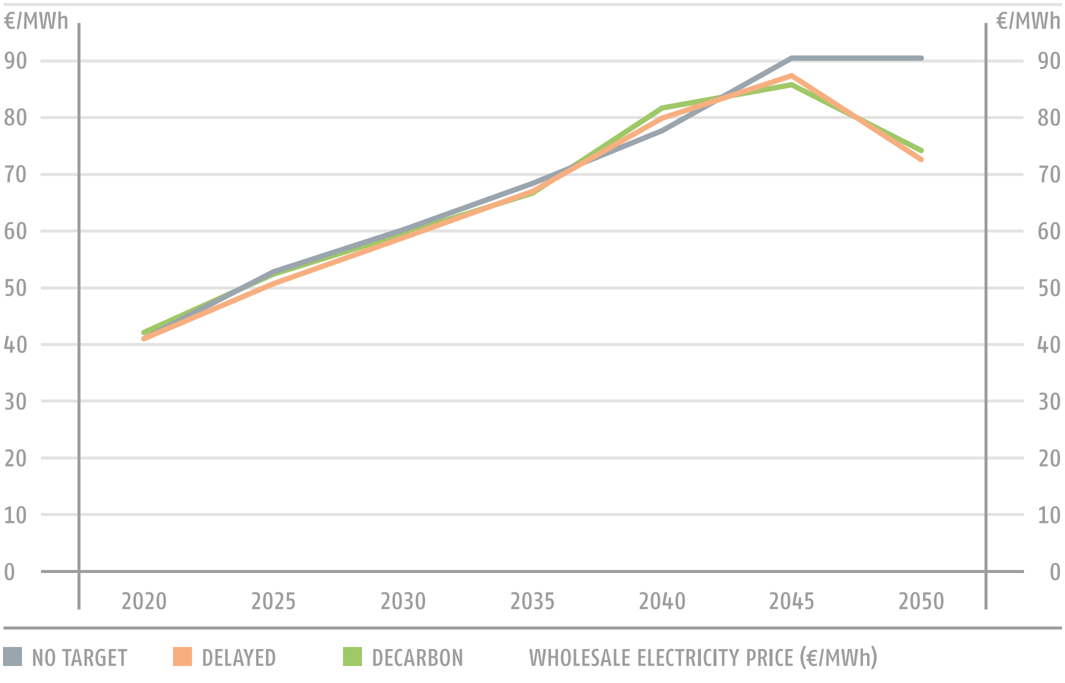


FIGURE 9
CUMULATIVE INVESTMENT COST FOR 4 AND 10 YEAR PERIODS, 2016-2050 (bn€)

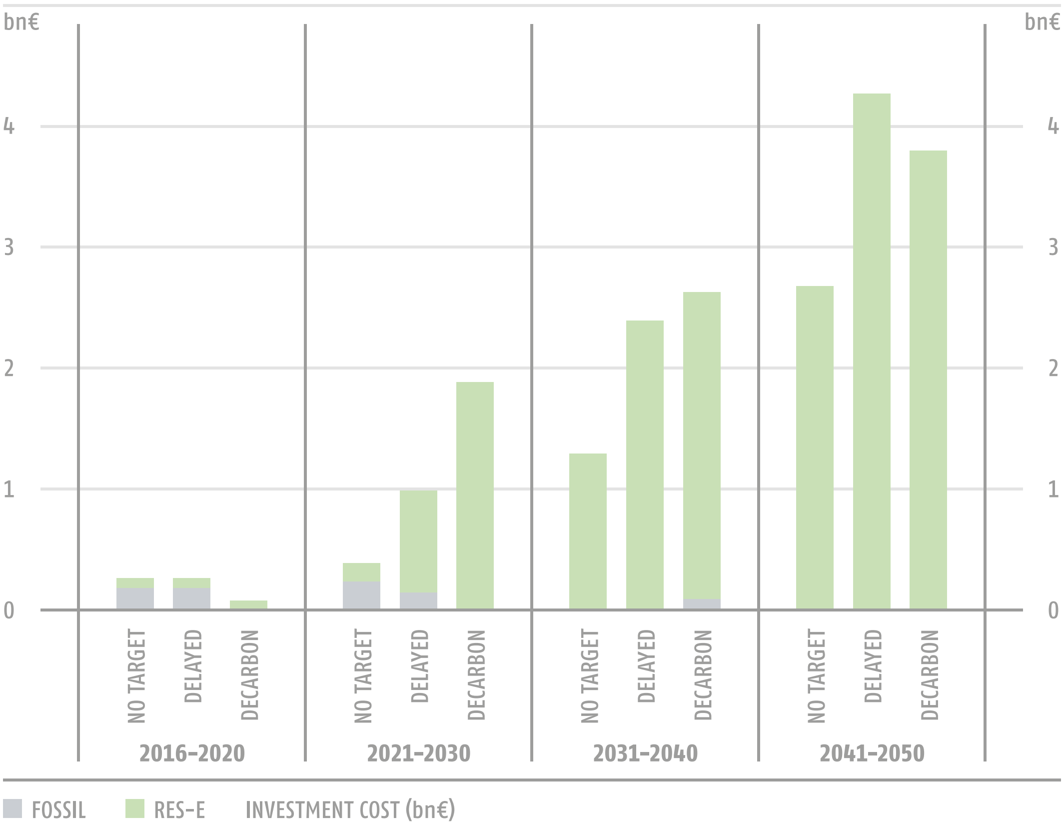
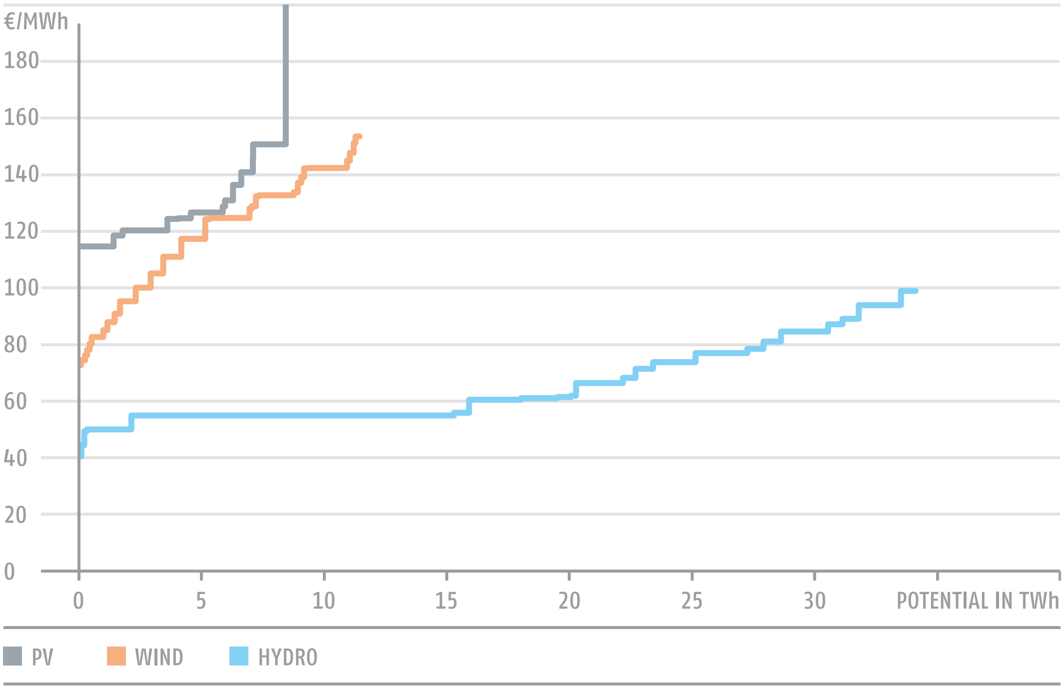


FIGURE 10
LONG TERM COST OF RENEWABLE TECHNOLOGIES IN ALBANIA (€/MWh)



modelled time horizon that are needed to achieve 2050 decarbonisation targets will require substantial support, estimated at 34% of total electricity cost over the last five years.

Although RES technologies are already at grid parity in some locations with costs falling further, some support will still be needed in 2050 to incentivise new investment. This is partly due to the locational impact: as the best locations with highest potential are used first, 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.

In the 'no target' scenario, RES-support is completely phased out by 2026. The growing need for support in the two other scenarios is partly explained by the fact that a relatively high utilisation rate of technical RES potential is foreseen by the end of the period (95% of wind in the 'delayed' scenario and 91% of hydro in the 'decarbonisation' scenario, with solar above 60% in both scenarios), suggesting that the effect of the locational impact which increases the need for support, is stronger than the effect of the increasing wholesale electricity price, 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 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.

With a heavier reliance on gas-fired generation, auction revenues are expected to be higher in Albania in the 'delayed' scenario than in the 'decarbonisation' scenario. However, overall RES support needed during the modelled time horizon is significantly higher than revenues in both scenarios. From a budgetary perspective, the 'no target' scenario is the most advantageous, as insignificant RES support (zero after 2025) is up against auction revenues that may come close to 50 mEUR in the 2030-40 and 2040-50 periods. On the other hand, the budgetary balance is especially unfavourable in the

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

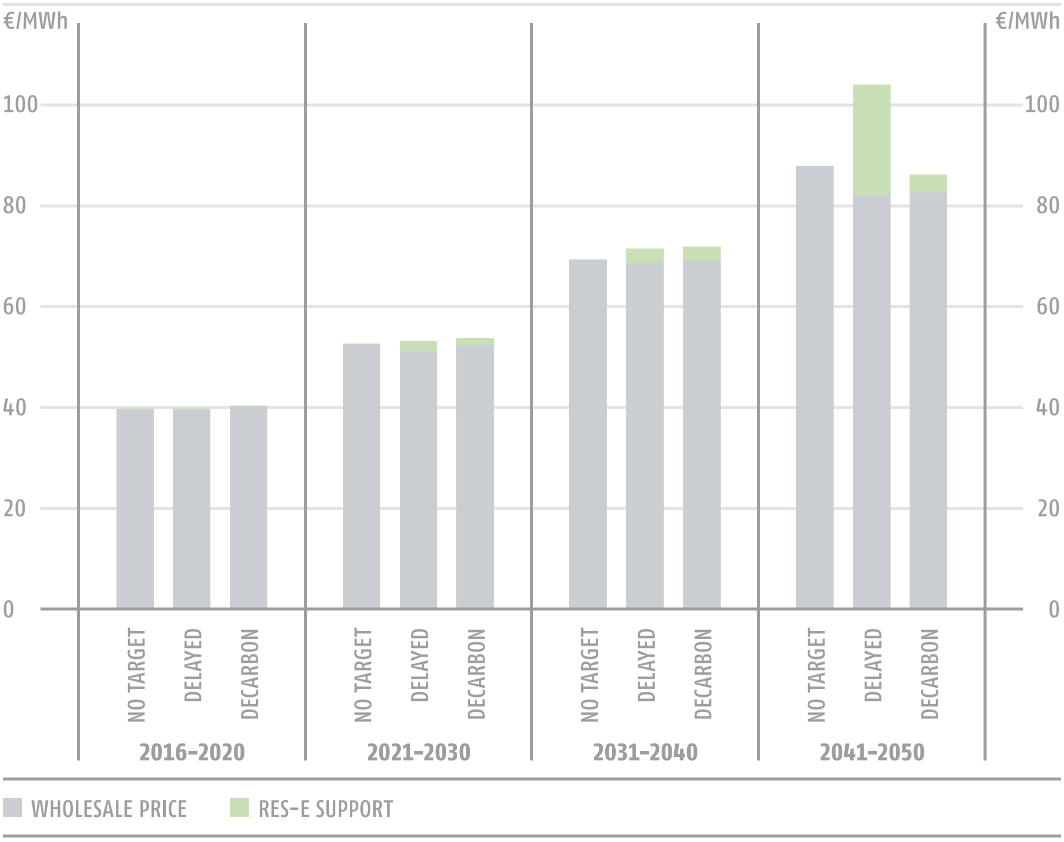
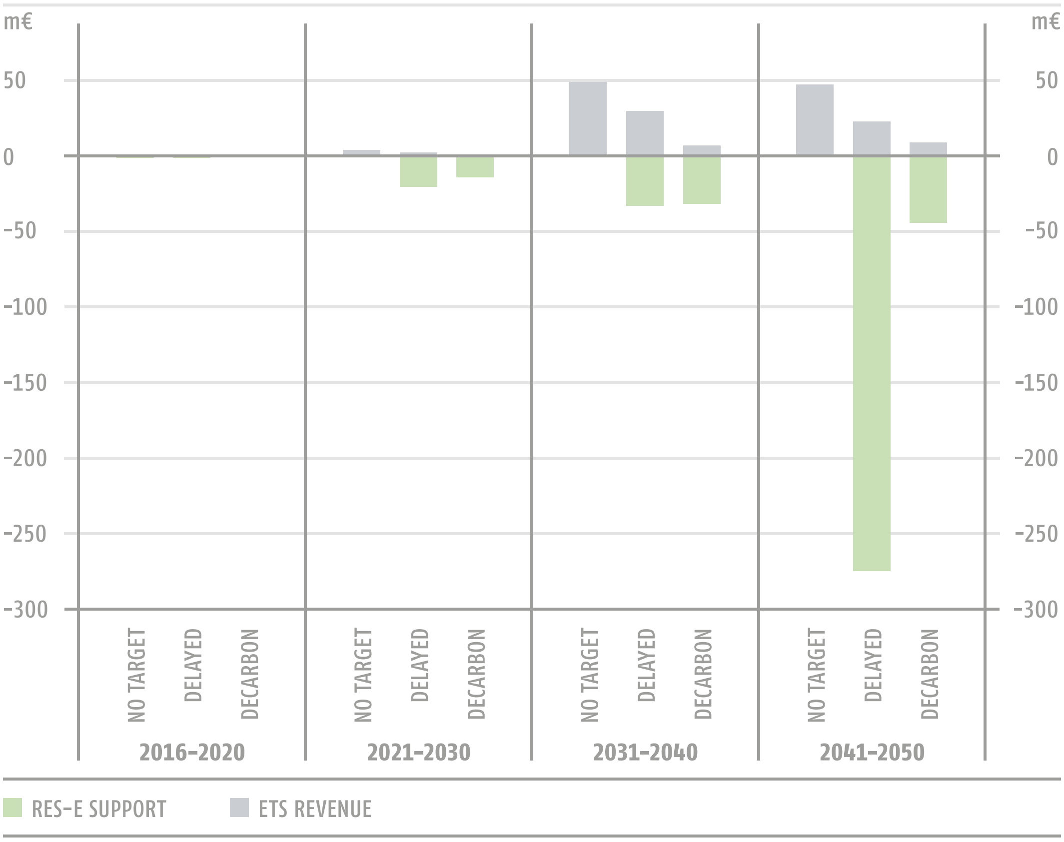


FIGURE 12
CUMULATIVE RES SUPPORT AND AUCTION REVENUES FOR 4 AND 10 YEAR PERIODS, 2016-2050 (m€)



2040s in the 'delayed' scenario, when support needs are expected to exceed auction revenues by more than 250 mEUR.

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 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 gas based capacities become unprofitable.

Based on this calculation, unprofitable gas-fired plants would receive 0.8 EUR/MWh in the 'no target' and 'delayed' scenarios, and 0.1 EUR/MWh in the 'decarbonisation' scenario, financed by a surcharge on consumption. Even though gas-fired capacities are expected to enter earlier in the 'delayed' scenario, providing them with a longer period of high utilisation rates, the smaller capacities in the 'decarbonisation' scenario result in lower overall stranded costs. These costs are not included in the wholesale price values shown in this report. Expressed as absolute values, stranded costs are expected to be around 100 mEUR in the 'no target' and 'delayed' scenarios, but only 7 mEUR in the 'decarbonisation' scenario.

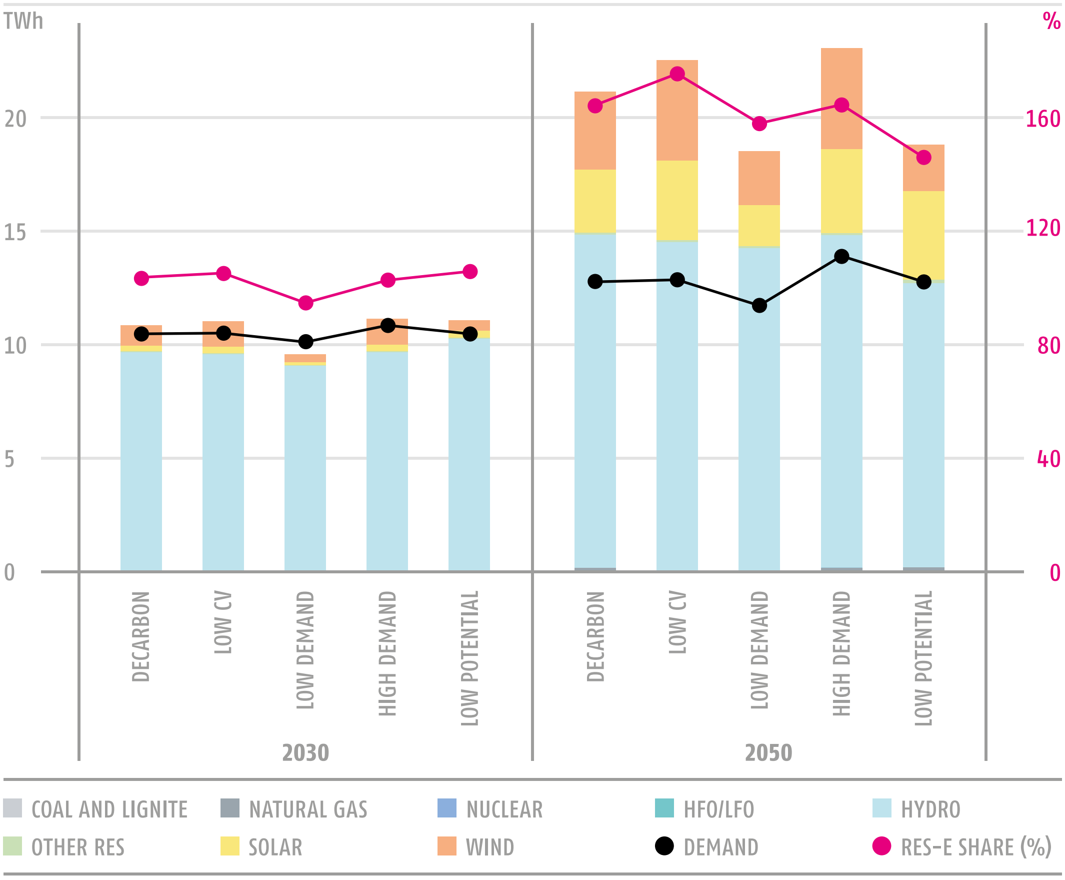
5.5 Sensitivity analysis

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

- Carbon price: to test the impact of a lower CO_2 price, a scenario was run which assumed that CO_2 prices would be half of the value used for the three core scenarios for the entire period until 2050;
- Demand: the impact of higher and lower demand growth was tested, with a +/-0.25% change in the growth rate for each year in all the modelled countries (EU28+WB6), resulting in a 8-9% deviation from the core trajectory by 2050;
- RES potential: the potential for large-scale hydropower and onshore wind power were assumed to be 25% lower than in the core scenarios; this is where the NIMBY effect is strongest and where capacity increase is least socially acceptable.

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

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



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

- The CO_2 price is a key determinant of wholesale price, with a 50% reduction in carbon price resulting in an approximately 33% decline in the wholesale price over the long term compared to the 'decarbonisation' scenario. However, to ensure that the same decarbonisation target is met, a higher RES support is required in this scenario, and as a result the sum of the wholesale price and RES support is second highest in this run.
- A lower carbon price would result in lower wholesale prices, making gas-fired generation uncompetitive; the 100 MW gas-fired capacity that is assumed to enter into production by 2035 in the 'decarbonisation' scenario is not expected to be deployed.
- The same holds for the low-demand scenario, with no gas-fired capacity expected to enter the generation portfolio. The utilisation rate of gas-fired capacities, however, is not very sensitive to higher demand.
- RES-based production more closely follows demand, with around +/- 10% difference compared to the reference case in the high and low demand sensitivity assessments.
- Lower hydro and wind potential results in 11% less electricity generation in 2050 compared to the 'decarbonisation' scenario, even though solar capacities are expected to be 41% higher. As solar is a more expensive technology option than hydro or wind, a significant increase in RES support is required in this sensitivity assessment compared with the 'decarbonisation' scenario. Albania is still a net exporter with 146% of RES as a share of consumption (as opposed to 164.4% in the 'decarbonisation' scenario).

5.6 Network

Albania's transmission system is already well-connected with the neighbouring countries but additional network investments in internal high voltage transmission lines and at the distribution level will be needed. The network will have to cope with higher RES integration and cross-border electricity trade and peak load that is expected to increase significantly from 1552 MW in 2016 (ENTSO-E DataBase) to 1893 MW in 2030 (SECI DataBase) and 2310 MW in 2050.

For the comparative assessment, a 'base case' network scenario was constructed with development 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 anticipates contingencies at internal 220 kV lines. These problems could be solved by investments in the range of 82-94 mEUR by 2050, depending on the scenario.

TABLE 1 | OVERLOADINGS IN THE ALBANIAN SYSTEM, 2030 AND 2050

	Overloading	Solution	Units (km or pcs)	Cost m€
2030	OHL220 kV VauDejes(AL) – Komani (AL)	New OHL 220 kV Komani (AL)-Titan (AL)	70	11.15
2050	OHL220 kV Fier (AL) – RRasbull (AL)	'Delayed' scenario: New TR 400/220 kV Fier (AL)	1	3
	OHL220 kV Fier (AL) – RRasbull (AL)	'Decarbonisation' scenario: New TR 400/220 kV Fier (AL) + Second line OHL220 kV Fier(AL) – RRasbull (AL)	1 + 80	3 + 12
	na	SS Skakavica (AL) + 400 kV OHLs (to Tirana (AL) and Prizren (KS)	130 + SS 400 kV	65

- **TTC and NTC assessment:** Total and Net Transfer Capacity (TTC/NTC) changes were evaluated between Albania 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 latter of which is not known) have a significant influence on NTC values between the Albanian and the neighbouring electricity systems. Figure 14 presents the changes in NTC values for 2030 and 2050, where two opposite impacts of higher RES deployments could be observed on the NTC values. First, high concentration of RES in a geographic area may cause congestion in the transmission network reducing NTCs and requiring further investment. Second, if RES generation replaces imported electricity, it may increase NTC for a given direction.

As the results show, NTC values generally increase in the RES intensive 'decarbonisation' and 'delayed' scenarios, with the exception of the neighbouring Greek system. This shows that the 'congestion' impact of RES is unlikely to seriously hinder the projected increase of Albania's net electricity export.

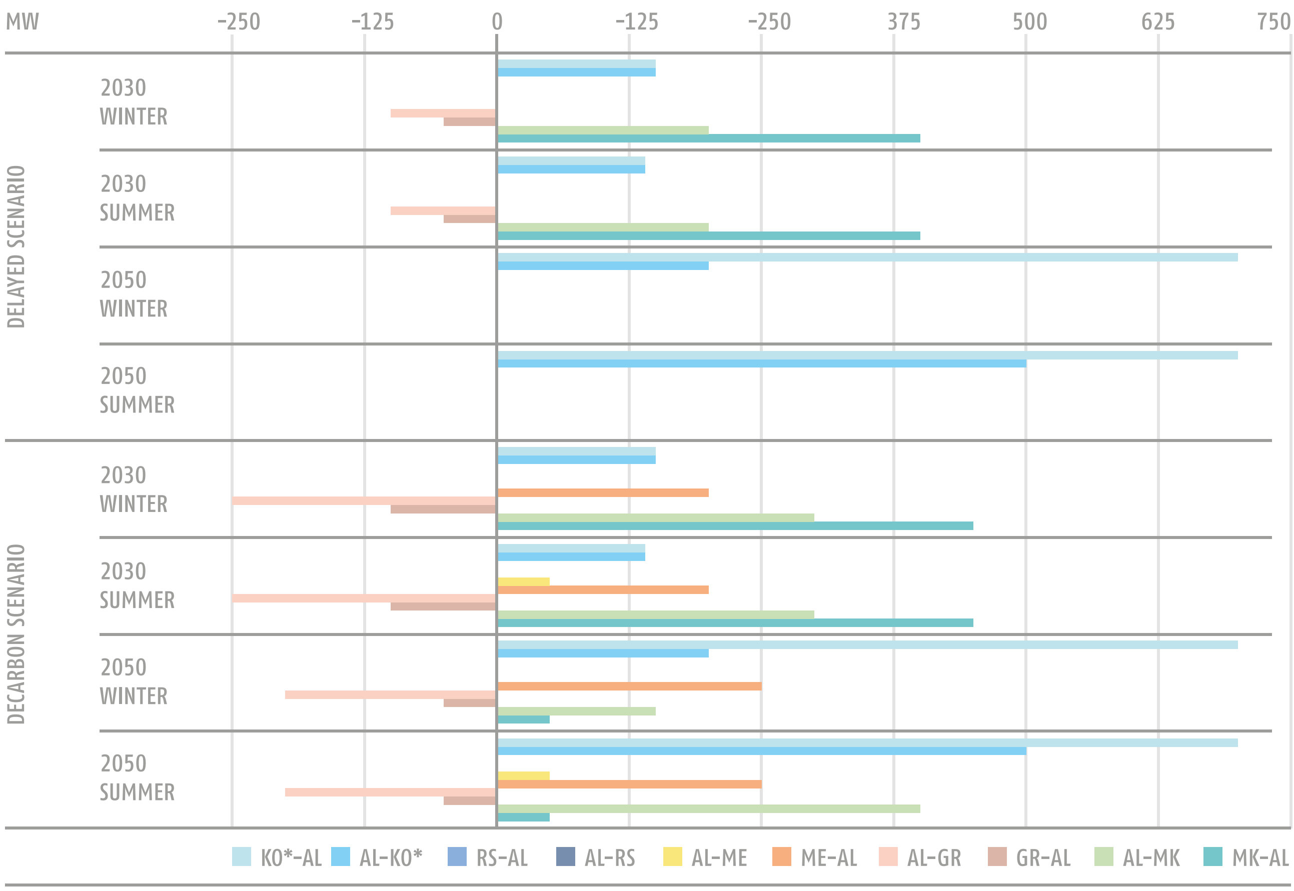


FIGURE 14
NTC VALUE CHANGES IN 2030 AND 2050 IN THE 'DELAYED' AND 'DECARBONISATION' SCENARIOS COMPARED TO THE 'BASE CASE' SCENARIO

- **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 and as a result the distance between production and consumption decreases. 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' and 'delayed' scenarios transmission losses fall significantly compared to the base case.

As the figure illustrates, the higher RES deployment in the two scenarios reduces transmission losses to around 5 MW in 2030 and to 5-8 MW in 2050 across the modelled hours as a non-weighted average of varying winter and summer figures. This represents a 19-20 GWh loss variation in a year in 2030. In 2050, the amount of avoided loss may be slightly less in the 'delayed' scenario (17 GWh), but close to 30 GWh in the 'decarbonisation' scenario. If monetised at the base-load price, the concurrent benefit of avoiding a loss of 20 GWh for TSOs is around 1.5 mEUR per year.

Overall, some investment in the transmission network is necessary to accommodate new RES capacities in the Albanian electricity system, but the estimated cost of network investments remain below 100 mEUR for the period, in addition to the ENTSO-E TYNDP development. 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.

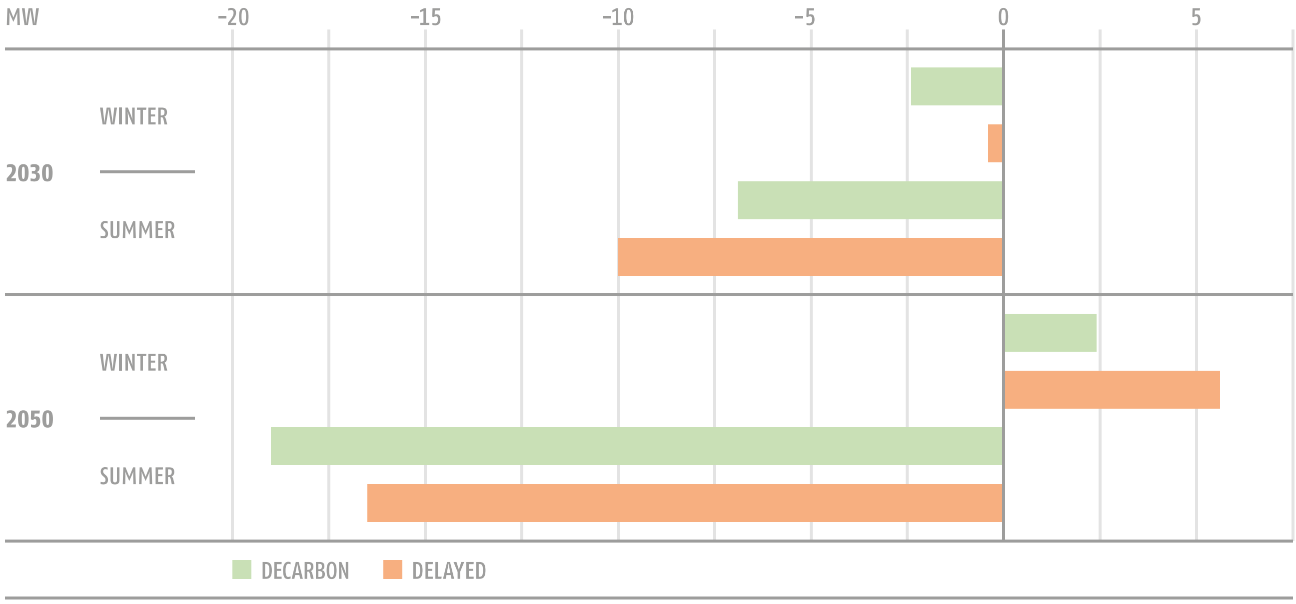


FIGURE 15
LOSS VARIATION COMPARED TO THE BASE CASE IN THE 'DELAYED' AND 'DECARBONISATION' SCENARIOS (MW, NEGATIVE VALUES INDICATE LOSS REDUCTION)

5.7 Macroeconomic impacts

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

The 'baseline' scenario suggests that Albania will experience economic growth of around 3% per annum until 2050, the second highest growth rate projected in the SEERMAP region. This ensures solid convergence towards the EU. Nonetheless substantial employment gains are not expected, following the country's traditionally weak performance in generating jobs. Both fiscal and external debt will stabilize around 50% of GDP, which is not extremely high but could be a source of vulnerability given the relatively low level of GDP per capita.

The 4.1% of household electricity expenditure to household income in 2016 is higher than the regional average of 2.5% and also than the EU average of 2.9%. In the 'baseline' scenario this ratio is projected to increase moderately until 2050.

The three core scenarios require some additional investment compared to the 'baseline' scenario, but even in the most intensive periods additional investment never exceeds 1% of GDP. In the 'no target' scenario, most of the investment is concentrated before 2020, while in the 'decarbonisation' scenario the intensive period starts after 2020, and remains relatively persistent. In the 'delayed' scenario there are two investment peaks, in the periods 2021-2025 and 2036-2040.

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.

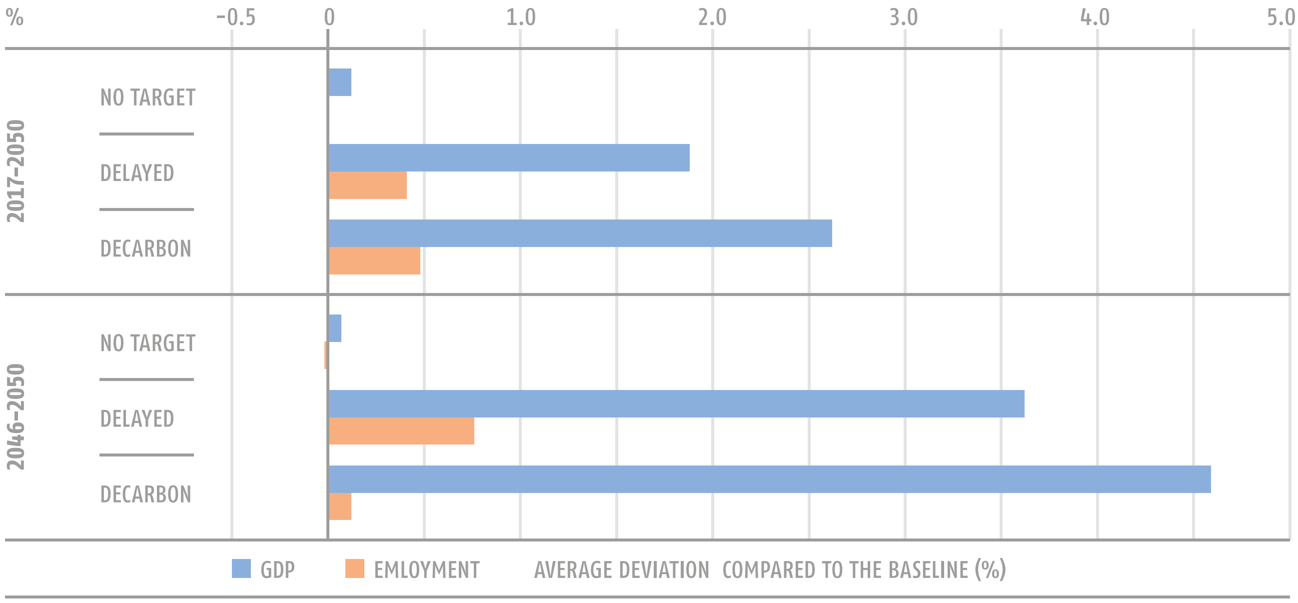


FIGURE 16
GDP AND EMPLOYMENT IMPACTS COMPARED WITH THE 'BASELINE' SCENARIO

Overall, the results suggest moderate macroeconomic gains from the three core scenarios. In the 'decarbonisation' scenario the GDP is on average 2.5% higher until 2050 compared to the 'baseline' scenario, leading to 4.5% higher real income per capita by the end of the period. Gains are somewhat more moderate in the 'delayed' scenario, dropping slightly below 2% on average and reaching a 3.5% long term GDP effect. For the 'no target' scenario, there is practically no GDP effect compared to the baseline. Employment effects are more muted and they mostly expire in the long term.

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.

All three core scenarios improve the macroeconomic vulnerability indicator of Albania. While public debt level remains practically constant across the scenarios, external debt decreases significantly, compared to the baseline; by 13% in the 'decarbonisation' scenario and 8% in the 'delayed' scenario, while remaining virtually constant in the 'no target' scenario. Differences in the external debt profiles are primarily explained by the fact that net energy imports (electricity and gas) do not change in the 'no target' scenario compared to the 'baseline' while gas imports decrease and net exports increase in the other two scenarios.

Public debt positions are affected by two main factors. First, intensive fossil investments raise carbon allowance related budget revenues in the 'no target' and 'delayed' scenarios, while in the 'decarbonisation' scenario less fossil investment decreases such revenues. Second,

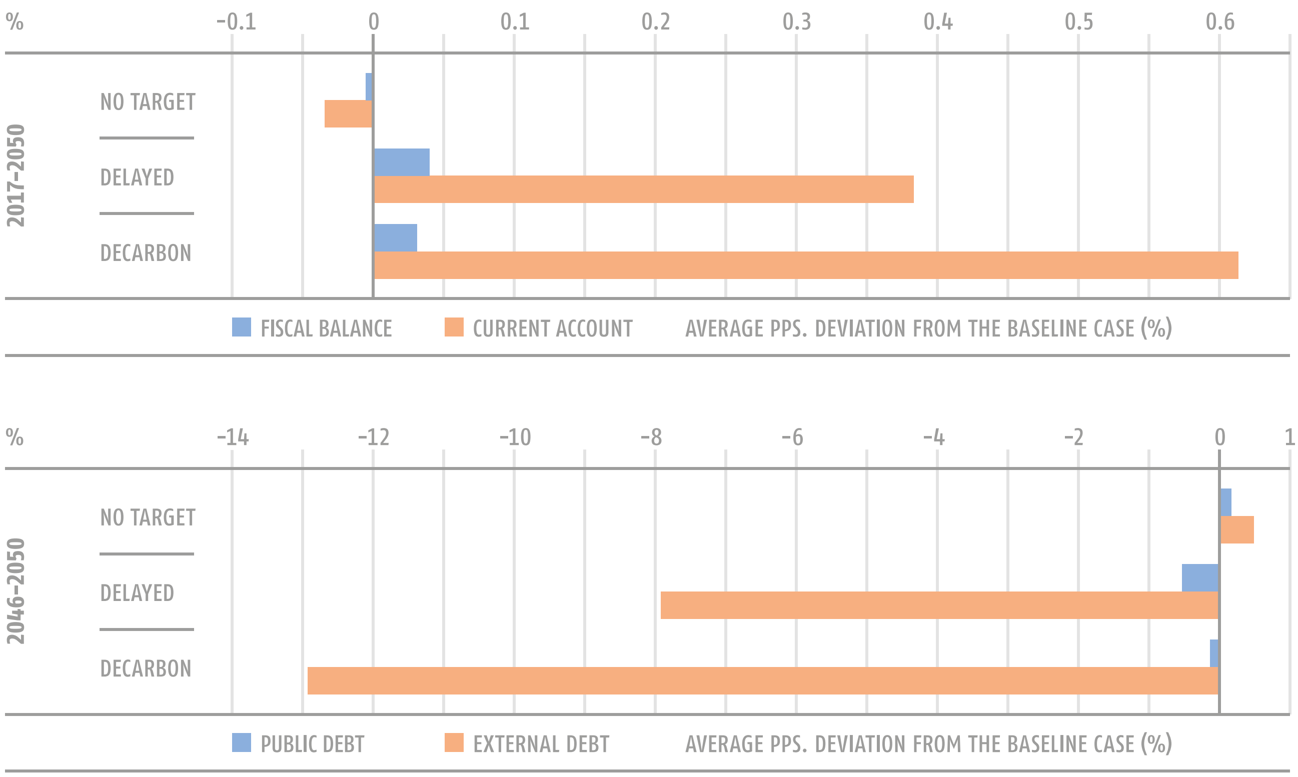


FIGURE 17
PUBLIC AND EXTERNAL BALANCES AND DEBT IMPACTS COMPARED WITH THE 'BASELINE' SCENARIO

a higher GDP increases budget revenues and decreases public debt by a simple scale effect (lower effective debt service). In the 'no target' and 'delayed' scenarios all of these effects lead to a lower level of public debt than in the 'baseline' scenario. In the 'decarbonisation' scenario, the effect of lower CO_2 revenues has a slightly greater impact compared to the baseline. The core scenarios have roughly no effect on the fiscal balance.

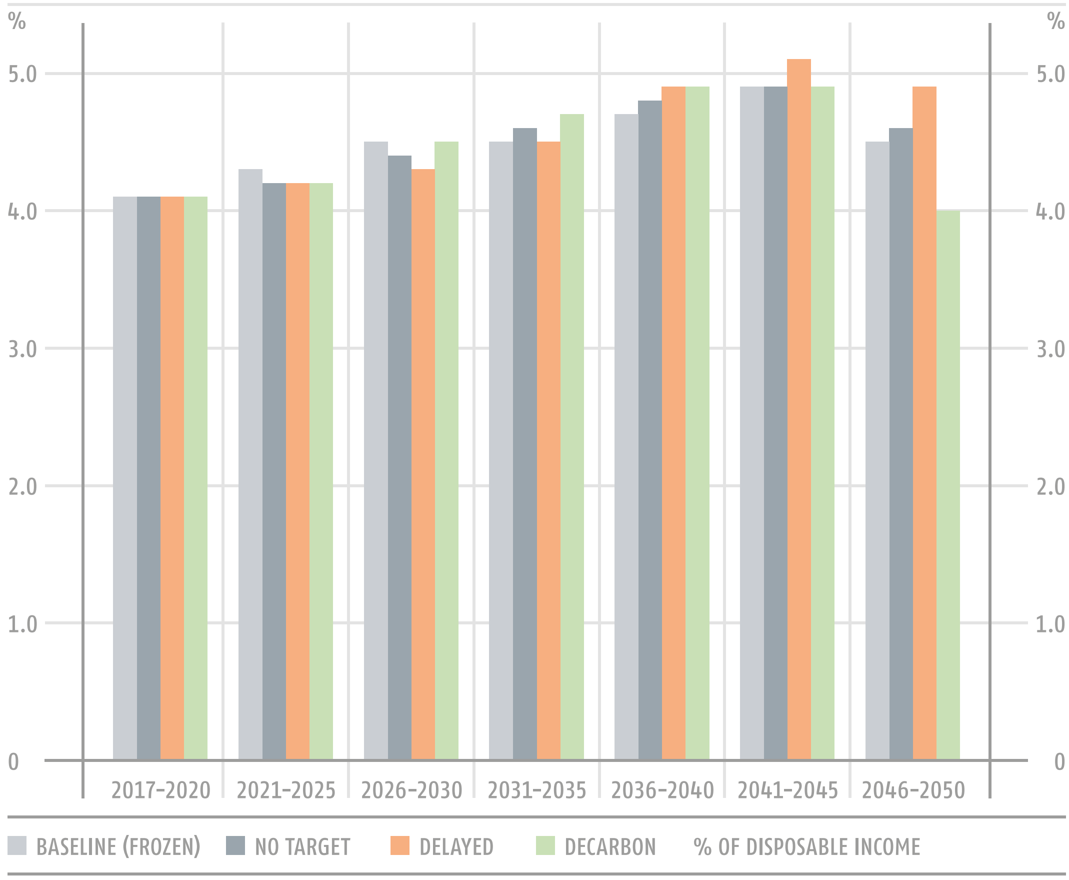
Affordability measures the burden of the electricity bill for households as the ratio of household electricity expenditure to household disposable income. The indicator is tracked closely throughout the whole period in order to identify notable increases.

Overall, the core scenarios do not affect household electricity expenditure significantly. The most pronounced difference is in the 'decarbonisation' scenario by 2050; in this scenario household electricity expenditure decreases to its current level after an increase over previous decades, as shown in Figure 18. This is primarily attributable to the large decrease in wholesale electricity prices at the end of the simulation period. At the same time in the 'delayed' scenario, the significant drop in wholesale electricity prices at the end of the projected time horizon is offset by the increase in RES support.

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 Albania 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.**

FIGURE 18
HOUSEHOLD ELECTRICITY EXPENDITURE 2017-2050



MAIN POLICY CONCLUSIONS

Regardless of whether or not Albania pursues an active policy to decarbonise its electricity sector, RES-based capacities will expand significantly:

- Albania is set to achieve a minimum of 123% of RES-share in electricity consumption under the modelled scenarios; the share of RES even reaches 165% in the 'delayed' and 'decarbonisation' scenarios;
- Gas-fired production becomes insignificant by 2050 in all scenarios, but has a transitional role in the 'no target' and 'delayed' scenarios;
- The high penetration of RES found in all scenarios suggests that Albanian energy policy should focus on enabling RES integration.

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

- Albania is expected to meet the overall EU indicative decarbonisation target for 2050 in all three scenarios, which gives the country room to evaluate a number of policy options;
- Installed generation capacity enables Albania to satisfy domestic demand using domestic generation in all seasons and hours of the day from around 2040 in the 'decarbonisation' scenario;
- Decarbonisation does not drive up wholesale prices relative to other less ambitious RES policy scenarios but, on the contrary, reduces them after 2045;

- The long term evolution of household electricity expenditure as a share of disposable income is most favourable in the 'decarbonisation' scenario;
- The 'decarbonisation' scenario has a number of positive implications according to the macroeconomic analysis, with the highest positive impact on GDP and the most favourable impact on the current account and external debt;
- However, implementing a long term planned effort to support RES is challenging as it will require significantly more investment, about 8.4 bnEUR over the 35-year period in the 'decarbonisation' scenario, compared with about 4.6 bnEUR in the 'no target' scenario.

Questions regarding the role of natural gas:

- A maximum of 460 MW gas-fired capacity is projected in the 'no target' scenario; in this scenario the share of natural gas in the electricity mix peaks in 2030 at 31% of electricity production and then falls to just 4% by 2050;
- In the 'decarbonisation' scenario, only 100 MW of gas-fired capacity is deployed by 2035, thus the share of gas in the electricity mix never surpasses 5%;
- The policy choice favouring the early installation of gas-fired capacities might be supported by the expectation that these capacities will be highly utilised until 2040, while capacities entering later in the 'decarbonisation' scenario would only experience utilisation rates above 50% for only 10-15 years. An assessment of the cost of stranded investments, however, favour the 'decarbonisation' scenario with a surcharge of only 0.1 EUR/MWh, as opposed to 0.8 EUR/MWh in the other two scenarios;
- The question of gas network capacity contracting may also be subject to Albania's choices made regarding the building of generation capacity.

6.1 Main electricity system trends

Albania is set to embark on an electricity sector development path that will lead to an energy mix based almost exclusively on RES capacities by 2050. Hydro capacities are likely to dominate its generation fleet throughout the projected time horizon, but Albania will gradually exploit its wind and solar potential as well with most new capacities expected to be deployed after 2030.

The country is facing a policy choice regarding the role of natural gas. Gas is projected to play a transitional role in the 'no target' and 'delayed' scenarios. In these scenarios gas-fired capacities will enter into production early in the modelled time horizon; in the former scenario the share of natural gas in the electricity mix is expected to peak in 2030 with 31% of electricity production. In the 'decarbonisation' scenario capacities enter later and the share of gas in the electricity mix never surpasses 5%.

Even if renewable subsidies are phased out without a CO_2 emission target, as assumed in the 'no target' scenario, gas-fired production becomes insignificant by 2050. The decline in natural gas based generation over the second half of the modelled time horizon is driven by increasing carbon and natural gas prices. The share of RES in electricity consumption will reach approximately 123% in the 'no target' scenario as a share of electricity consumption. This will result in 95% emission reduction which is significantly higher than the indicative decarbonisation target of the EU for the electricity sector. In the other two scenarios, the RES-share in consumption might reach around 165%. Due to its expanding production capacities, Albania will become net electricity exporter by 2030 in all scenarios.

The high penetration of RES in all scenarios suggests that a robust no-regret action for Albanian 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.

A long term planned effort seems more advantageous than delayed action. First, the stranded cost of gas generation assets is significantly lower in the 'decarbonisation' scenario, at around 7 mEUR compared with 97 mEUR in the 'delayed' scenario. Second, if action is delayed, **the disproportionate effort needed towards the end of the modelled period to enable the CO_2 emissions target to be reached requires a significant increase in RES support in the 'delayed' scenario.**

6.2 Security of supply

Albania is expected to become a net electricity exporter by 2030 in all scenarios. Due to the high level of connectivity with its neighbours, **its system adequacy margin is positive throughout the entire period,** and installed generation capacity within the country enables Albania to satisfy domestic demand using domestic generation in all seasons and hours of the day from around 2040.

In order to address intermittency of a significant share of the installed generation capacity, Albania 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 Albania would need to invest in its transmission and distribution network. Depending on the scenario, network investments range from an estimated 82 to 94 mEUR beyond investments needed to implement the ENTSO-E 2016 TYNDP.

6.3 Sustainability

Albania has a high potential of renewables, especially hydro and wind, and thus can make a higher than average contribution to meeting 2050 emission reduction targets compared to other countries. In Albania CO_2 emissions are reduced in the electricity sector by 99% in the 'decarbonisation' scenario, but even if no decarbonisation target is set, emission reduction is projected to reach 95%, which is higher than the 94% target set in the model for the EU28+Western Balkans region as a whole. The high RES potential is an asset for Albania, enabling the country to reach emission reduction targets without disproportionate effort, and to become a net electricity exporter.

Renewable potential can be reaped through policies eliminating barriers to RES investment. **A no-regret step involves de-risking policies addressing high financing costs and high cost of capital** to 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 in which 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, applied across all scenarios, and the price of natural gas, because natural gas based production is the marginal production unit needed to meet demand in a significant number of hours of the year in the region.

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

Under all scenarios there is a significant increase in the wholesale electricity price compared with current (albeit historically low) price levels. This 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 as an increased wholesale price is likely to result in increased end user prices. However, the price increase also has a positive impact in terms of attracts investment needed to replace outgoing capacity. Rising electricity prices can be observed in the entire SEE region and across all the EU in all scenarios for the modelled time period. In addition, **the macroeconomic analysis shows that despite the high absolute increase in wholesale prices, the core scenarios do not affect household electricity expenditure significantly due to a strong increase in household disposable income.** The increase in electricity expenditure relative to household income is lowest in the 'decarbonisation' scenario over the long term.

Policies aiming at a higher level of decarbonisation – delayed or not – 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. From a social point of view, the high level of investment has a positive impact on GDP. At the same time, in the long term, the external debt decreases by 13% in the 'decarbonisation' scenario and by 8% in the 'delayed' scenario as a result of higher net energy exports enabled by bigger RES-based generation capacities.

Although not modelled in full detail, **wholesale price volatility of electricity is also expected to increase,** ceteris paribus, in a world with a high share of intermittent renewables. **Demand 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.

The 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 SEERMAP region than in 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 a no-regret step, yielding minimal system cost and consumer expenditures.**

In the 'no target' scenario, RES-support is completely phased out by 2026. The increasing need for support in the two other scenarios may be explained by the fact that a relatively high utilisation rate of technical RES potential is foreseen by the end of the period. However, the need for support is limited by increasing electricity wholesale prices that incentivise significant RES investment even without support. **The significant difference between support needs in the 'delayed' and in the 'decarbonisation' scenario at the end of the modelled period provides a strong argument favouring long-term planning.** Long-term planning would also provide investors with the necessary stability to ensure that higher level of renewable investments will take place.

7 | References

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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	0	0	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	200	360	460	460	460	460	260
	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		1 801	1 866	1 866	1 977	2 274	2 638	3 032	3 413
	Wind		0	0	0	0	28	200	784	1 066
	Solar		2	2	2	2	29	78	249	585
	Other RES		5	5	5	8	8	10	16	19
Gross consumption, GWh			8 267	9 330	9 894	10 471	11 072	11 641	12 246	12 703
Net electricity generation, GWh	Total		6 752	8 551	9 834	10 686	12 119	13 543	15 934	16 263
	Coal and lignite		0	0	0	0	0	0	0	0
	Natural gas		0	1 557	2 838	3 266	3 500	3 162	2 721	631
	Nuclear		0	0	0	0	0	0	0	0
	HFO/LFO		0	0	0	0	0	0	0	0
	Hydro		6 730	6 972	6 972	7 388	8 498	9 858	11 331	12 755
	Wind		0	0	0	0	53	381	1 496	2 034
	Solar		3	3	3	3	38	102	326	767
	Other RES		19	19	21	29	31	40	61	75
Net import, GWh	Total		1 515	778	60	-215	-1 048	-1 902	-3 688	-3 560
	ME		2 034	865	-1 272	-120	-769	-629	-2 396	-832
	GR		-1 217	-470	1 028	507	1 071	-354	-1 153	-175
	IT		0	0	0	0	0	0	0	0
	MK		0	87	590	-457	-429	-849	-618	-645
	KO		697	296	-287	-144	-921	-70	479	-1 907
Net import ratio, %			18.3%	8.3%	0.6%	-2.1%	-9.5%	-16.3%	-30.1%	-28.0%
RES-E share (RES-E production/gross consumption, %)			81.7%	75.0%	70.7%	70.9%	77.9%	89.2%	107.9%	123.1%
Utilisation rates of RES-E technical potential, %	Hydro		na	na	na	na	na	na	na	79%
	Wind		na	na	na	na	na	na	na	44%
	Solar		na	na	na	na	na	na	na	18%
Utilisation rates of conventional power production, %	Coal and lignite		na	na	na	na	na	na	na	na
	Natural gas		na	88.9%	90.0%	81.1%	86.8%	78.5%	67.5%	27.7%
	Nuclear		na	na	na	na	na	na	na	na
Natural gas consumption of power generation, TWh			0	2.78	5.03	5.75	6.16	5.56	4.78	1.10
Security of supply	Generation adequacy margin		-36%	-25%	-17%	-12%	-8%	3%	18%	20%
	System adequacy margin		61%	62%	54%	50%	45%	46%	64%	62%
CO_2 emission	Emission, Mt CO_2		0	0.6	1.0	1.2	1.2	1.1	1.0	0.2
	CO_2 emission reduction compared to 1990, %		100%	87.3%	77.1%	73.8%	71.9%	74.6%	78.2%	95.0%
Spreads	Clean dark spread, €(2015)/MWh		25.4	30.8	42.8	14.7	13.5	13.9	6.5	-13.6
	Clean spark spread, €(2015)/MWh		-165.3	2.5	8.7	-1.2	-1.1	-2.2	-2.6	-10.3
Price impacts	Electricity wholesale price, €(2015)/MWh		34.7	41.0	52.8	60.2	68.4	77.7	90.5	90.5
	Total RES-E support/gross consumption, €(2015)/MWh, five year average		na	0.1	0	0	0	0	0	0
	Revenue from CO_2 auction/gross consumption, €(2015)/MWh		0	0	0	3.7	4.7	4.8	5.4	1.5
Investment cost, m€/5 year period	Coal and lignite		na	0	0	0	0	0	0	0
	Natural gas		na	184	147	92	0	0	0	0
	Total Fossil		na	184	147	92	0	0	0	0
	Total RES-E		na	82	1	151	491	803	1 472	1 211
	Total		na	266	148	243	491	803	1 472	1 211
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		100.00	19.27	22.05	23.97	26.31	29.89	32.67	32.71
	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	0	0	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	200	360	360	360	360	360	160
	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		1 801	1 866	2 148	2 280	2 634	3 052	3 434	3 779
	Wind		0	0	122	134	192	816	1 582	2 295
	Solar		2	2	60	73	156	452	1 073	1 950
	Other RES		5	5	7	10	12	15	18	24
Gross consumption, GWh			8 267	9 330	9 900	10 476	11 077	11 634	12 258	12 770
Net electricity generation, GWh	Total		6 752	8 547	11 205	10 878	12 693	15 402	18 442	21 352
	Coal and lignite		0	0	0	0	0	0	0	0
	Natural gas		0	1 553	2 838	1 970	2 233	1 791	1 114	290
	Nuclear		0	0	0	0	0	0	0	0
	HFO/LFO		0	0	0	0	0	0	0	0
	Hydro		6 730	6 972	8 029	8 518	9 844	11 403	12 830	14 078
	Wind		0	0	232	257	366	1 557	3 019	4 364
	Solar		3	3	79	96	205	593	1 408	2 528
	Other RES		19	19	27	37	45	56	71	92
Net import, GWh	Total		1 515	782	-1 305	-402	-1 617	-3 768	-6 184	-8 582
	ME		2 060	835	-1 596	136	277	-28	-753	-977
	GR		-1 244	-403	357	-381	-146	-134	-604	-358
	IT		0	0	0	0	0	0	0	0
	MK		0	5	410	-118	-978	-545	-952	-897
	KO		699	344	-477	-39	-770	-3 061	-3 874	-6 349
Net import ratio, %			18.3%	8.4%	-13.2%	-3.8%	-14.6%	-32.4%	-50.4%	-67.2%
RES-E share (RES-E production/gross consumption, %)			81.7%	75.0%	84.5%	85.0%	94.4%	117.0%	141.4%	164.9%
Utilisation rates of RES-E technical potential, %	Hydro		na	na	na	na	na	na	na	88%
	Wind		na	na	na	na	na	na	na	95%
	Solar		na	na	na	na	na	na	na	61%
Utilisation rates of conventional power production, %	Coal and lignite		na	na	na	na	na	na	na	na
	Natural gas		na	88.6%	90.0%	62.5%	70.8%	56.8%	35.3%	20.7%
	Nuclear		na	na	na	na	na	na	na	na
Natural gas consumption of power generation, TWh			0	2.77	5.03	3.48	3.96	3.17	1.97	0.51
Security of supply	Generation adequacy margin		-36%	-25%	-8%	-9%	-4%	11%	27%	31%
	System adequacy margin		61%	62%	61%	54%	45%	43%	67%	72%
CO_2 emission	Emission, Mt CO_2		0	0.6	1.0	0.7	0.8	0.6	0.4	0.1
	CO_2 emission reduction compared to 1990, %		100%	87.4%	77.1%	84.1%	82.0%	85.5%	91.0%	97.7%
Spreads	Clean dark spread, €(2015)/MWh		25.4	30.8	40.6	13.4	12.0	16.2	3.4	-31.5
	Clean spark spread, €(2015)/MWh		-165.3	2.4	6.6	-2.6	-2.5	0.1	-5.7	-28.2
Price impacts	Electricity wholesale price, €(2015)/MWh		34.7	41.0	50.7	58.8	67.0	79.9	87.4	72.6
	Total RES-E support/gross consumption, €(2015)/MWh, five year average		na	0.1	3.6	0.5	1.5	4.3	6.3	37.4
	Revenue from CO_2 auction/gross consumption, €(2015)/MWh		0	0	0	2.2	3.0	2.7	2.2	0.7
Investment cost, m€/5 year period	Coal and lignite		na	0	0	0	0	0	0	0
	Natural gas		na	184	147	0	0	0	0	0
	Total Fossil		na	184	147	0	0	0	0	0
	Total RES-E		na	82	606	234	703	1 694	2 168	2 104
	Total		na	266	753	234	703	1 694	2 168	2 104
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		100.00	19.27	22.05	23.97	26.31	29.89	32.67	32.71
	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	0	0	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		1 801	1 866	2 217	2 588	3 010	3 387	3 739	3 941
	Wind		0	0	147	471	638	805	1 320	1 806
	Solar		2	2	66	197	492	1 286	1 970	2 141
	Other RES		5	5	7	10	12	16	19	22
Gross consumption, GWh			8 267	9 326	9 895	10 473	11 077	11 627	12 263	12 765
Net electricity generation, GWh	Total		6 752	6 994	8 681	10 866	13 834	16 547	19 579	21 156
	Coal and lignite		0	0	0	0	0	0	0	0
	Natural gas		0	0	0	0	673	608	449	171
	Nuclear		0	0	0	0	0	0	0	0
	HFO/LFO		0	0	0	0	0	0	0	0
	Hydro		6 730	6 972	8 286	9 672	11 250	12 656	13 962	14 685
	Wind		0	0	281	898	1 219	1 536	2 518	3 435
	Solar		3	3	87	258	645	1 687	2 576	2 780
	Other RES		19	19	27	37	48	60	75	85
Net import, GWh	Total		1 515	2 332	1 214	-393	-2 757	-4 920	-7 316	-8 392
	ME		2 060	1 060	-212	-565	-114	-383	4	262
	GR		-1 244	234	1 423	960	775	115	79	379
	IT		0	0	0	0	0	0	0	0
	MK		0	182	137	-541	-1 057	-690	-1 533	-1 002
	KO		699	856	-134	-247	-2 361	-3 962	-5 865	-8 031
Net import ratio, %			18.3%	25.0%	12.3%	-3.7%	-24.9%	-42.3%	-59.7%	-65.7%
RES-E share (RES-E production/gross consumption, %)			81.7%	75.0%	87.7%	103.7%	118.8%	137.1%	156.0%	164.4%
Utilisation rates of RES-E technical potential, %	Hydro		na	na	na	na	na	na	na	91%
	Wind		na	na	na	na	na	na	na	74%
	Solar		na	na	na	na	na	na	na	67%
Utilisation rates of conventional power production, %	Coal and lignite		na	na	na	na	na	na	na	na
	Natural gas		na	na	na	na	76.8%	69.4%	51.3%	19.5%
	Nuclear		na	na	na	na	na	na	na	na
Natural gas consumption of power generation, TWh			0	0	0	0	1.16	1.05	0.77	0.29
Security of supply	Generation adequacy margin		-36%	-41%	-33%	-24%	-8%	9%	22%	30%
	System adequacy margin		61%	55%	50%	47%	41%	38%	58%	59%
CO_2 emission	Emission, Mt CO_2		0	0	0	0	0.2	0.2	0.2	0.1
	CO_2 emission reduction compared to 1990, %		100%	100%	100%	100%	94.7%	95.2%	96.5%	98.7%
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		-165.3	3.6	8.3	-1.9	-2.8	1.8	-7.2	-26.6
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	0.1	0.8	2.0	2.8	2.7	2.8	4.3
	Revenue from CO_2 auction/gross consumption, €(2015)/MWh		0	0	0	0	0.9	0.9	0.9	0.4
Investment cost, m€/5 year period	Coal and lignite		na	0	0	0	0	0	0	0
	Natural gas		na	0	0	0	91.6	0	0	0
	Total Fossil		na	0	0	0	91.6	0	0	0
	Total RES-E		na	82	748	1 138	1 080	1 460	1 811	1 991
	Total		na	82	748	1 138	1 171	1 460	1 811	1 991
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		100.00	19.27	22.05	23.97	26.31	29.89	32.67	32.71
	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	0	0	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		1 801	1 842	2 196	2 564	2 987	3 361	3 718	3 920
	Wind		0	0	176	594	814	1 222	1 823	2 355
	Solar		2	2	75	223	692	1 630	2 127	2 758
	Other RES		5	5	8	10	13	17	20	23
Gross consumption, GWh			8 273	9 336	9 912	10 505	11 118	11 659	12 325	12 855
Net electricity generation, GWh	Total		6 752	6 904	8 669	11 047	13 677	17 097	20 108	22 556
	Coal and lignite		0	0	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		6 730	6 882	8 205	9 581	11 164	12 561	13 828	14 511
	Wind		0	0	336	1 134	1 554	2 333	3 461	4 449
	Solar		3	3	99	293	908	2 138	2 741	3 505
	Other RES		19	19	30	40	50	65	78	91
Net import, GWh	Total		1 521	2 432	1 243	-542	-2 558	-5 438	-7 783	-9 701
	ME		1 943	2 214	13	-44	-90	-648	-848	-1 648
	GR		-1 083	-900	1 030	170	151	63	-233	-429
	IT		0	0	0	0	0	0	0	0
	MK		0	124	100	-489	-832	-1 036	-1 066	-830
	KO		661	994	100	-179	-1 788	-3 817	-5 636	-6 794
Net import ratio, %			18.4%	26.0%	12.5%	-5.2%	-23.0%	-46.6%	-63.1%	-75.5%
RES-E share (RES-E production/gross consumption, %)			81.6%	74.0%	87.5%	105.2%	123.0%	146.6%	163.1%	175.5%
Utilisation rates of RES-E technical potential, %	Hydro		na	na	na	na	na	na	na	90.8%
	Wind		na	na	na	na	na	na	na	97.1%
	Solar		na	na	na	na	na	na	na	86.8%
Utilisation rates of conventional power production, %	Coal and lignite		na	na	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		-36%	-41%	-33%	-25%	-13%	5%	17%	28%
	System adequacy margin		61%	55%	52%	49%	45%	42%	64%	66%
CO_2 emission	Emission, Mt CO_2		0	0	0	0	0	0	0	0
	CO_2 emission reduction compared to 1990, %		100%	100%	100%	100%	100%	100%	100%	100%
Spreads	Clean dark spread, €(2015)/MWh		22.5	28.4	36.4	3.3	-1.4	7.8	-15.5	-54.3
	Clean spark spread, €(2015)/MWh		-168.2	0	2.4	-12.7	-16.0	-8.3	-24.7	-50.9
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	0.1	10.4	14.7	21.2	23.9	27.9	53.3
	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	49	799	1 289	1 327	1 844	1 922	1 950
	Total		na	49	799	1 289	1 327	1 844	1 922	1 950
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		100.00	19.27	22.05	23.97	26.31	29.89	32.67	32.71
	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	0	0	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		1 801	1 866	2 148	2 428	2 823	3 176	3 556	3 821
	Wind		0	0	122	180	277	532	1 190	1 244
	Solar		2	2	60	93	217	536	1 056	1 385
	Other RES		5	5	7	10	12	15	18	21
Gross consumption, GWh			8 267	9 235	9 675	10 111	10 552	10 925	11 410	11 720
Net electricity generation, GWh	Total		6 752	6 994	8 368	9 575	11 410	13 643	17 011	18 521
	Coal and lignite		0	0	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		6 730	6 972	8 029	9 072	10 550	11 869	13 285	14 260
	Wind		0	0	233	344	529	1 015	2 270	2 371
	Solar		3	3	79	122	285	703	1 384	1 807
	Other RES		19	19	27	37	46	56	72	83
Net import, GWh	Total		1 515	2 240	1 307	536	-858	-2 718	-5 601	-6 801
	ME		1 870	1 125	-441	342	973	-5	482	488
	GR		-1 257	-128	1 479	1 134	644	610	106	724
	IT		0	0	0	0	0	0	0	0
	MK		0	373	617	-474	-804	-632	-1 011	-1 030
	KO		902	870	-349	-466	-1 671	-2 691	-5 177	-6 982
Net import ratio, %			18.3%	24.3%	13.5%	5.3%	-8.1%	-24.9%	-49.1%	-58.0%
RES-E share (RES-E production/gross consumption, %)			81.7%	75.7%	86.5%	94.7%	108.1%	124.9%	149.1%	158.0%
Utilisation rates of RES-E technical potential, %	Hydro		na	na	na	na	na	na	na	88.5%
	Wind		na	na	na	na	na	na	na	51.3%
	Solar		na	na	na	na	na	na	na	43.6%
Utilisation rates of conventional power production, %	Coal and lignite		na	na	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		-36%	-40%	-34%	-28%	-11%	3%	20%	32%
	System adequacy margin		61%	56%	52%	46%	41%	36%	61%	59%
CO_2 emission	Emission, Mt CO_2		0	0	0	0	0	0	0	0
	CO_2 emission reduction compared to 1990, %		100%	100%	100%	100%	100%	100%	100%	100%
Spreads	Clean dark spread, €(2015)/MWh		25.4	31.6	42.3	14.6	15.3	25.2	0	-29.1
	Clean spark spread, €(2015)/MWh		-165.3	3.3	8.3	-1.4	0.7	9.1	-9.1	-25.7
Price impacts	Electricity wholesale price, €(2015)/MWh		34.7	41.8	52.4	60.0	70.2	89.0	83.9	75.1
	Total RES-E support/gross consumption, €(2015)/MWh, five year average		na	0.1	5.2	2.4	3.2	0.6	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	82	607	543	845	1 179	1 977	909
	Total		na	82	607	543	845	1 179	1 977	909
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		100.00	19.27	22.05	23.97	26.31	29.89	32.67	32.71
	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	0	0	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		1 801	1 866	2 217	2 588	3 010	3 387	3 739	3 941
	Wind		0	0	176	594	884	1 230	1 795	2 352
	Solar		2	2	75	223	692	1 670	2 438	2 869
	Other RES		5	5	8	11	13	17	20	23
Gross consumption, GWh			8 267	9 419	10 119	10 846	11 616	12 351	13 199	13 906
Net electricity generation, GWh	Total		6 752	6 994	8 751	11 140	14 534	17 835	20 952	23 075
	Coal and lignite		0	0	0	0	0	0	0	0
	Natural gas		0	0	0	0	637	575	391	182
	Nuclear		0	0	0	0	0	0	0	0
	HFO/LFO		0	0	0	0	0	0	0	0
	Hydro		6 730	6 972	8 286	9 672	11 250	12 656	13 918	14 647
	Wind		0	0	336	1 134	1 688	2 349	3 411	4 462
	Solar		3	3	99	293	908	2 190	3 152	3 693
	Other RES		19	19	30	41	51	66	79	90
Net import, GWh	Total		1 515	2 425	1 368	-294	-2 918	-5 484	-7 753	-9 169
	ME		2 139	691	18	27	-319	-138	-632	-912
	GR		-1 208	394	1 565	763	667	-138	-116	10
	IT		0	0	0	0	0	0	0	0
	MK		0	673	161	-871	-398	-942	-1 196	-840
	KO		584	667	-376	-213	-2 868	-4 267	-5 809	-7 426
Net import ratio, %			18.3%	25.7%	13.5%	-2.7%	-25.1%	-44.4%	-58.7%	-65.9%
RES-E share (RES-E production/gross consumption, %)			81.7%	74.3%	86.5%	102.7%	119.6%	139.7%	155.8%	164.6%
Utilisation rates of RES-E technical potential, %	Hydro		na	na	na	na	na	na	na	91.2%
	Wind		na	na	na	na	na	na	na	97.0%
	Solar		na	na	na	na	na	na	na	90.3%
Utilisation rates of conventional power production, %	Coal and lignite		na	na	na	na	na	na	na	na
	Natural gas		na	na	na	na	72.7%	65.6%	44.7%	20.8%
	Nuclear		na	na	na	na	na	na	na	na
Natural gas consumption of power generation, TWh			0	0	0	0	1.1	1.0	0.7	0.3
Security of supply	Generation adequacy margin		-36%	-41%	-34%	-27%	-10%	6%	18%	25%
	System adequacy margin		61%	53%	49%	45%	42%	38%	57%	58%
CO_2 emission	Emission, Mt CO_2		0	0	0	0	0.2	0.2	0.1	0.1
	CO_2 emission reduction compared to 1990, %		100%	100%	100%	100%	95.0%	95.5%	96.9%	98.6%
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		-165.3	3.9	8.6	11.5	13.9	20.2	16.5	6.5
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	0.1	10.1	11.4	14.7	14.0	13.4	31.4
	Revenue from CO_2 auction/gross consumption, €(2015)/MWh		0	0	0	0	0.8	0.8	0.7	0.4
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	82	804	1 287	1 420	1 797	2 053	1 864
	Total		na	82	804	1 287	1 420	1 797	2 053	1 864
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		100.00	19.27	22.05	23.97	26.31	29.89	32.67	32.71
	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	0	0	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		1 801	1 865	2 277	2 748	3 194	3 366	3 366	3 366
	Wind		0	0	149	235	342	593	1 008	1 083
	Solar		2	2	77	242	773	1 552	2 474	3 020
	Other RES		5	5	8	11	13	17	21	35
Gross consumption, GWh			8 267	9 326	9 895	10 473	11 077	11 627	12 269	12 765
Net electricity generation, GWh	Total		6 752	6 991	8 922	11 078	14 326	16 423	18 243	18 824
	Coal and lignite		0	0	0	0	0	0	0	0
	Natural gas		0	0	0	0	674	608	452	188
	Nuclear		0	0	0	0	0	0	0	0
	HFO/LFO		0	0	0	0	0	0	0	0
	Hydro		6 730	6 969	8 508	10 270	11 936	12 581	12 562	12 534
	Wind		0	0	283	449	652	1 132	1 920	2 058
	Solar		3	3	100	318	1 014	2 036	3 228	3 908
	Other RES		19	19	30	41	51	66	81	136
Net import, GWh	Total		1 515	2 336	972	-605	-3 249	-4 797	-5 974	-6 059
	ME		1 868	749	-824	-478	-495	-374	-419	500
	GR		-1 307	213	1 672	1 108	656	184	-228	11
	IT		0	0	0	0	0	0	0	0
	MK		0	557	263	-660	-981	-849	-1 321	-1 003
	KO		954	816	-139	-575	-2 430	-3 758	-4 006	-5 567
Net import ratio, %			18.3%	25.0%	9.8%	-5.8%	-29.3%	-41.3%	-48.7%	-47.5%
RES-E share (RES-E production/gross consumption, %)			81.7%	75.0%	90.2%	105.8%	123.2%	136.0%	145.0%	146.0%
Utilisation rates of RES-E technical potential, %	Hydro		na	na	na	na	na	na	na	77.9%
	Wind		na	na	na	na	na	na	na	44.7%
	Solar		na	na	na	na	na	na	na	95.0%
Utilisation rates of conventional power production, %	Coal and lignite		na	na	na	na	na	na	na	na
	Natural gas		na	na	na	na	76.9%	69.4%	51.6%	21.4%
	Nuclear		na	na	na	na	na	na	na	na
Natural gas consumption of power generation, TWh			0	0	0	0	1.2	1.0	0.8	0.3
Security of supply	Generation adequacy margin		-36%	-41%	-31%	-19%	0%	6%	9%	10%
	System adequacy margin		61%	54%	50%	45%	41%	35%	56%	56%
CO_2 emission	Emission, Mt CO_2		0	0	0	0	0.2	0.2	0.2	0.1
	CO_2 emission reduction compared to 1990, %		100%	100%	100%	100%	94.7%	95.2%	96.4%	98.5%
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		-165.3	3.7	8.4	11.7	14.2	21.9	19.0	8.8
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	0.1	10.3	8.7	11.9	12.2	14.4	102.7
	Revenue from CO_2 auction/gross consumption, €(2015)/MWh		0	0	0	0	0.9	0.9	0.9	0.4
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	85	873	1 091	1 499	1 258	1 278	592
	Total		na	85	873	1 091	1 499	1 258	1 278	592
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		100.00	19.27	22.05	23.97	26.31	29.89	32.67	32.71
	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	40	50	153
Solid biomass	0	2	130
Biowaste	0	0	0
Geothermal ele.	0	0	3
Hydro large-scale	1 542	1 921	2 278
Hydro small-scale	952	1 298	1 305
Central PV	73	523	1 095
Decentralised PV	302	813	793
CSP	0	0	0
Wind onshore	1 300	2 980	2 546
Wind offshore	1	3	5
RES-E total	4 210	7 590	8 309

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	**5**	**2**	**0**	**0**	**0**	**0**	**0**	**7**
Central PV								
Decentralised PV								
Wind onshore								
Delayed	**5**	**177**	**27**	**82**	**248**	**385**	**2 362**	**3 287**
Central PV		6	1	1	4	13	167	192
Decentralised PV		4	1	3	15	33	229	284
Wind onshore		41	6	14	63	128	819	1 070
Decarbon	**5**	**38**	**103**	**156**	**159**	**171**	**270**	**900**
Central PV		7	12	17	23	28	133	219
Decentralised PV		2	3	1	0	0	6	13
Wind onshore		27	83	93	40	0	37	281

Annex 2 | Assumptions

Assumed technology investment cost trajectories: RES and fossil

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

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

Source: Green-X database

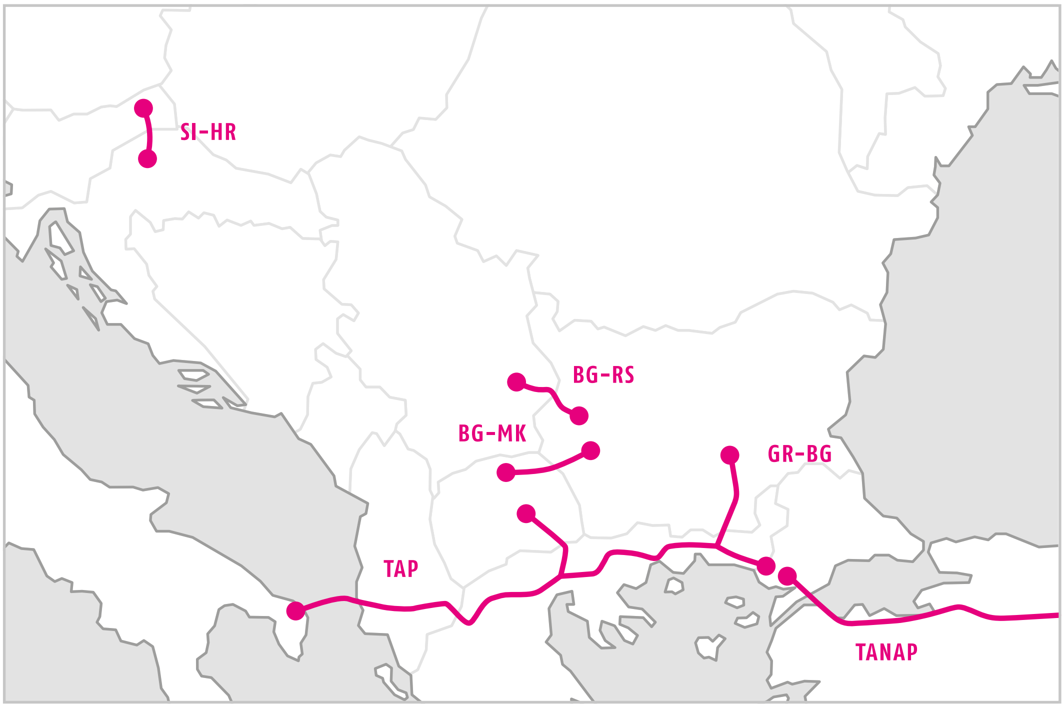
Infrastructure (table for the whole region)

TABLE A11 | NEW GAS INFRASTRUCTURE IN THE REGION

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

Source: ENTSO-G TYNDP

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



Source: ENTSO-G TYNDP 2017

TABLE A12 | CROSS BORDER TRANSMISSION NETWORK CAPACITIES

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

Source: ENTSO-E TYNDP 2017

Generation units and their inclusion in the core scenarios

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

Unit name	Installed capacity [MW]	Expected year of commissioning	Expected year of decommissioning	Fuel type	Type	CCS	No target	Delay	De-carbon
CCGT Vlora I. – 200	200	2020	2050	natural gas	thermal	no	yes	yes	no
CCGT Vlora I. – 160	160	2025	2055	natural gas	thermal	no	yes	yes	no

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