

SOUTH EAST EUROPE ELECTRICITY ROADMAP

Country report

Greece



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

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

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

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



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

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



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



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



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



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



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

Local partners in SEERMAP target countries



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.



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



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



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



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



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



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

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1 | Executive summary

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

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

In Greece, approximately 40% of current fossil generation capacity, more than 5000 MW, is expected to be decommissioned by the end of 2030, and 95% of current generation capacity will be decommissioned by 2050. This provides both a challenge to ensure a policy framework which will incentivise needed new investment, and an opportunity to shape the electricity sector over the long term in line with a broader energy transition unconstrained by the current generation portfolio.

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

- The 'no target' scenario reflects the implementation of existing energy policy (including implementation of renewable energy targets for 2020 and construction of all power plants included in official planning documents) combined with a CO₂ price (which is only envisaged from 2030 onwards for non EU member states). The scenario does not include an explicit 2050 CO₂ target or a renewables target for the electricity sectors of the EU member states or countries in the Western Balkans;
- The 'decarbonisation' scenario reflects a long-term strategy to significantly reduce CO₂ emissions, in line with indicative EU emission reduction goals for the electricity sector as a whole by 2050, driven by the CO₂ price and strong, consistent RES support;
- The 'delayed' scenario involves an initial implementation of current national investment plans (business-as-usual policies) followed by a change in policy direction from 2035 onwards, resulting in the realisation of the same emission reduction target in 2050 as the 'decarbonisation' scenario. Decarbonisation is driven by the CO₂ price and increased RES support from 2035 onwards.

The modelling work carried out under the SEERMAP project identifies some key findings with respect to the different electricity strategies that Greece can pursue:

- Under scenarios with an ambitious decarbonisation target and corresponding RES support schemes, Greece will have an electricity mix with close to 100% renewable generation, mostly solar and wind, and some hydro by 2050. If renewable support is phased out and no CO₂ emission target is set, the share of RES in electricity consumption will reach around

65% in 2050. While this represents a significant increase compared to current levels, it is insufficient compared with decarbonisation levels targeted by the EU by 2050.

- Delayed action on renewables is feasible, but has two disadvantages compared with a long term planned effort. It results in stranded fossil fuel power generation assets, including currently planned power plants. Translated into a price increase equivalent over a 10 year period, the cost of stranded assets is on par with the size of RES support needed for decarbonising the electricity sector. Furthermore, the increased effort required towards the end of the modelled period to meet the CO₂ emission reduction target requires a significant increase in RES support.
- Whether or not Greece pursues an active policy to support renewable electricity generation, a significant replacement of fossil fuel generation capacity will take place; coal, lignite and oil capacities are phased out under all scenarios by 2050. The decrease in the share of these fuels begins early, driven by the rising price of carbon which results in unprofitable utilisation rates. Oil is completely phased out by 2030 and the share of coal falls to around 10% of total generation by 2040 in all scenarios.
- Natural gas will remain relevant in the coming decades, with utilisation increasing in all scenarios initially. However, under a 'decarbonisation' scenario which is in line with the EU decarbonisation target of 93-99%, gas plays only a very minor role by 2050. In this scenario new gas capacity has to be installed only to replace outgoing gas power plants but no capacity increase is required in order to bridge the transition from fossil fuel to renewable based electricity mix; rather, the required higher gas powered generation can be achieved through higher utilisation rates of gas capacities. Under the 'no target' scenario, gas generation peaks close to 2035 and remains an important component even in 2050.
- In the two scenarios with a decarbonisation target, Greece is able to produce the same amount of electricity as it consumes throughout the modelling period; both generation and system adequacy indicators remain favourable as well. In the 'no target' scenario Greece is a net exporter for around two decades.
- Decarbonisation of the electricity sector does not drive up wholesale electricity prices compared to a scenario where no emission reduction target is set. The price of electricity follows a similar trajectory under all scenarios and only diverges after 2045. After this year, prices are lower in scenarios with high levels of RES in the electricity mix due to the low marginal cost of RES electricity production.
- Under all scenarios there is a significant increase in the wholesale electricity price compared with current (albeit historically low) price levels. This increase characterises the entire SEE region, and in fact the EU as a whole, in all scenarios for the modelled time period. The increase is driven by the price of carbon and the price of natural gas, both of which increase significantly by 2050. While this will result in higher absolute end user prices, the macroeconomic analysis shows that household electricity expenditure relative to household income is expected to decrease in all scenarios in Greece since the increase in household income will outpace the increase in electricity expenditure. A benefit of higher wholesale prices is the positive signal it sends to investors in a sector currently beset by underinvestment.
- Decarbonisation will require significantly more investment in generation capacity, assumed to be financed by private actors who accept higher CAPEX in exchange for low OPEX (plus RES support) in their investment decisions. From a social point of view, the high level of investment has a positive impact on GDP and a small positive impact on employment. At the same time, with higher levels of renewables, the external debt decreases around 2% of GDP in the long term resulting from improvement in the current account due to lower gas imports compared to the baseline.

- Decarbonisation will require continued RES support during the entire period. However, the need for support decreases as electricity wholesale prices increase and incentivise significant RES investment even without support.
- Required network investments in distribution, transmission and cross border capacities are significant.

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

- The high penetration of RES in all scenarios suggests a policy focus on enabling RES integration; this involves investing in transmission and distribution networks, enabling demand side management and RES production through a combination of technical solutions and appropriate regulatory practices, and promoting investment in storage solutions including hydro and small scale storage.
- RES potential can be maximised through policies eliminating barriers to RES investment. De-risking policies addressing the high financing cost of capital prevalent throughout the region and in Greece would pave the way for cost-efficient renewable energy investments.
- Co-benefits of investing in renewable electricity generation can strengthen the case for increased RES investment, including a boost to GDP as a result of increased investment in generation capacity, an improved external balance due to reduced gas imports, and lower wholesale energy price which can result from high penetration of RES. Additional co-benefits, not assessed here, are health and environmental benefits from reduced emissions of air pollutants.
- In order to enable Greece to decarbonise its electricity sector to the level suggested by the EU Roadmap, an active, long-term and stable renewable energy support framework is needed. A significant share of the RES support for decarbonisation of the electricity sector can be covered by EU ETS revenues, thereby reducing the corresponding surcharge to consumers.
- Policy makers need to address the trade-offs which characterise fossil fuel investments. Coal and oil generation capacities are expected to be priced out of the market before the end of their lifetime in all scenarios; this is also true for gas generation capacities under scenarios with an ambitious decarbonisation target, resulting in stranded assets. These long term costs need to be weighed against any short term benefits, particularly associated with gas, that temporarily bridges the transition from coal and lignite to renewables.
- Regional level planning, including establishment of regional markets, increasing cross-border capacities and incentivising storage options with a regional significance, can improve system adequacy compared with plans which emphasise reliance on national production capacities.

2 | Introduction

2.1 Policy context

Over the past decades EU energy policy has focused on a number of shifting priorities. Beginning in the 1990s, the EU started a process of market liberalisation in order

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

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

2.2 The SEERMAP project at a glance

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

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

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

The aim of the analysis is to show the challenges and opportunities ahead and the trade-offs between different policy goals. The project can also contribute to a better understanding of the benefits that regional cooperation can provide for all involved countries. Although ultimately energy policy decisions will need to be taken by national policy makers, these decisions must recognise the interdependence of investment and regulatory decisions of neighbouring countries. Rather than outline specific policy advice 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

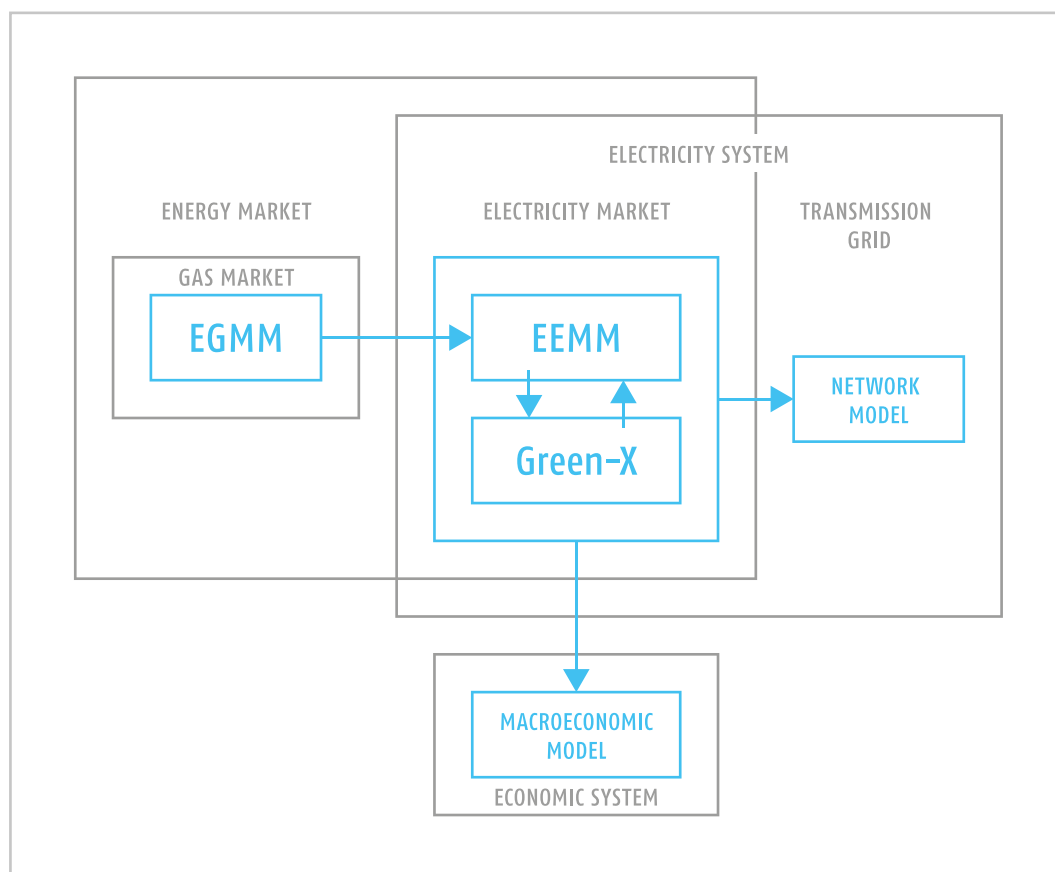
This report summarises the contribution of the SEERMAP project to the ongoing policy debate on how to enhance the decarbonisation of the electricity sector in Greece. We inform on the work undertaken, present key results gained and offer a summary of key findings and recommendations on the way forward. 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, whereby power plant operators anticipate costs over the upcoming 10 years and make investment decisions based exclusively on profitability. If framework conditions (e.g. fuel prices, carbon price, available generation capacities) change beyond this timeframe then the utilisation of these capacities may change and profitability is not guaranteed.

FIGURE 1
THE FIVE MODELS
USED FOR THE
ANALYSIS

*A detailed
description of the
models is provided
in a separate
document
("Models used in
SEERMAP")*



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

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

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

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

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

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

4 | Scenario descriptions and main assumptions

4.1 Scenarios

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

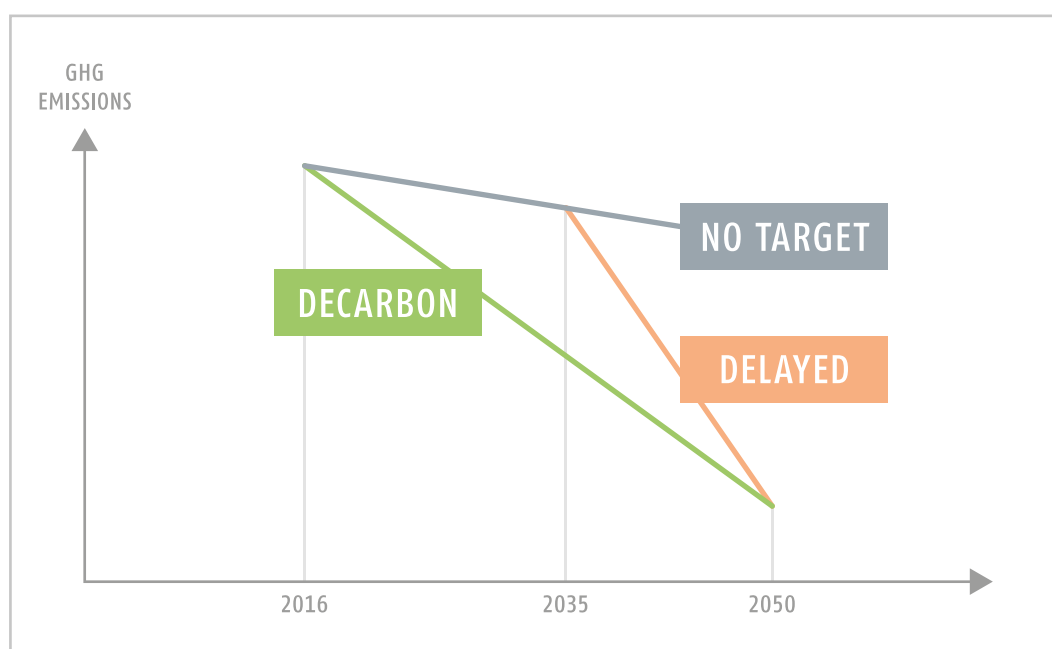
- The 'no target' scenario reflects the implementation of current energy policy and no CO₂ target in the EU and Western Balkans for 2050;
- The 'decarbonisation' scenario reflects a continuous effort to reach significant reductions of CO₂ emissions, in line with the long term indicative EU emission reduction goal of 93-99% for the electricity sector as a whole by 2050;
- The 'delayed' scenario involves an initial implementation of current investment plans followed by a change in policy direction from 2035 onwards, resulting in the realisation of the same emission reduction target in 2050 as the 'decarbonisation' scenario.

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

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

The scenarios differ with respect to the mix of new technologies, included in the model in one of two ways: (i) the new power plants entered exogenously into the model based

FIGURE 2
THE CORE
SCENARIOS



on policy documents, and (ii) the different levels and timing of RES support resulting in different endogenous RES investment decisions. The assumptions of the three core scenarios are the following:

- In the 'no target' scenario all currently planned fossil fuel power plants are entered into the model exogenously. Information on planned power plants is taken from official national strategies/plans and information received from the local partners involved in the project. We have assumed the continuation of current renewable support policies up to 2020 and the gradual phasing out of support between 2021 and 2025. The scenario assumes countries meet their 2020 renewable target but do not set a CO₂ emission reduction target for 2050. Although a CO₂ target is not imposed, producers face CO₂ prices in this scenario, as well as in the others.
- In the 'decarbonisation' scenario, only those planned investments which had a final investment decision in 2016 were considered, resulting in lower exogenous fossil fuel capacity. With a 94% CO₂ 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 CO₂ 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 CO₂ 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. For Greece, the PRIMES EU Reference scenario growth rates were used from 2015 onwards due to lack of trustworthy projections. This means an average annual electricity growth rate of 0.2% over the period between 2016 and 2050. 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. In late 2016, the Greek TSO published its 10-year development plan (HTSO 2016) forecasting higher demand growth, namely 0.3% for the period 2021-2024 and 0.45% for the period 2025-2027. Greek fiscal developments in the last 10 years make long term projections especially in the near and medium term difficult.
- 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 while the price of oil and coal were taken from IEA (2016) and EIA (2017) respectively. The price of coal is expected to increase by approximately 15% between 2016 and 2050; in the same period gas prices increase by around 90% and oil prices by around 250%, because of historically low prices in 2016. Compared to 2012-2013 levels, this would mean an only 15-20% increase by 2050.
- Cost of different technologies: Information on the investment cost of new generation technologies is taken from EIA (2017).
- Weighted average cost of capital (WACC): The WACC has a significant impact on the cost of investment, with a higher WACC implying a lower net present value and therefore a more limited scope for profitable investment. The WACCs used in the modelling are country-specific, these values are modified by technology-specific and policy instrument-specific risk factors. The country-specific WACC for Greece was assumed to be 14.6% in 2015, decreasing to 11.2% by 2050. The estimated WACC for onshore wind and PV are in line with Ecofys – Eclareon (2017), where values are 10.5-13.7% and 7.3-12.4% for the two technologies respectively.
- Carbon price: a price for carbon is applied for the entire modelling period for EU member states and from 2030 onwards for non-member states, under the assumption that all candidate and potential candidate countries will implement the EU Emissions Trading Scheme or a corresponding scheme by 2030. The carbon price is assumed to increase

from 33.5 EUR/tCO₂ in 2030 to 88 EUR/tCO₂ 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 up to 2050. For example, the Impact Assessment of the Energy Roadmap 2050 projected carbon prices as high as 310 EUR under various scenarios by 2050 (EC 2011b). The EU ETS carbon price is determined by the marginal abatement cost of the most expensive abatement option, which means that the last reduction units required by the EU climate targets will be costly, resulting in steeply increasing carbon price in the post 2030 period.

Infrastructure:

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

Renewable energy sources and technologies:

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

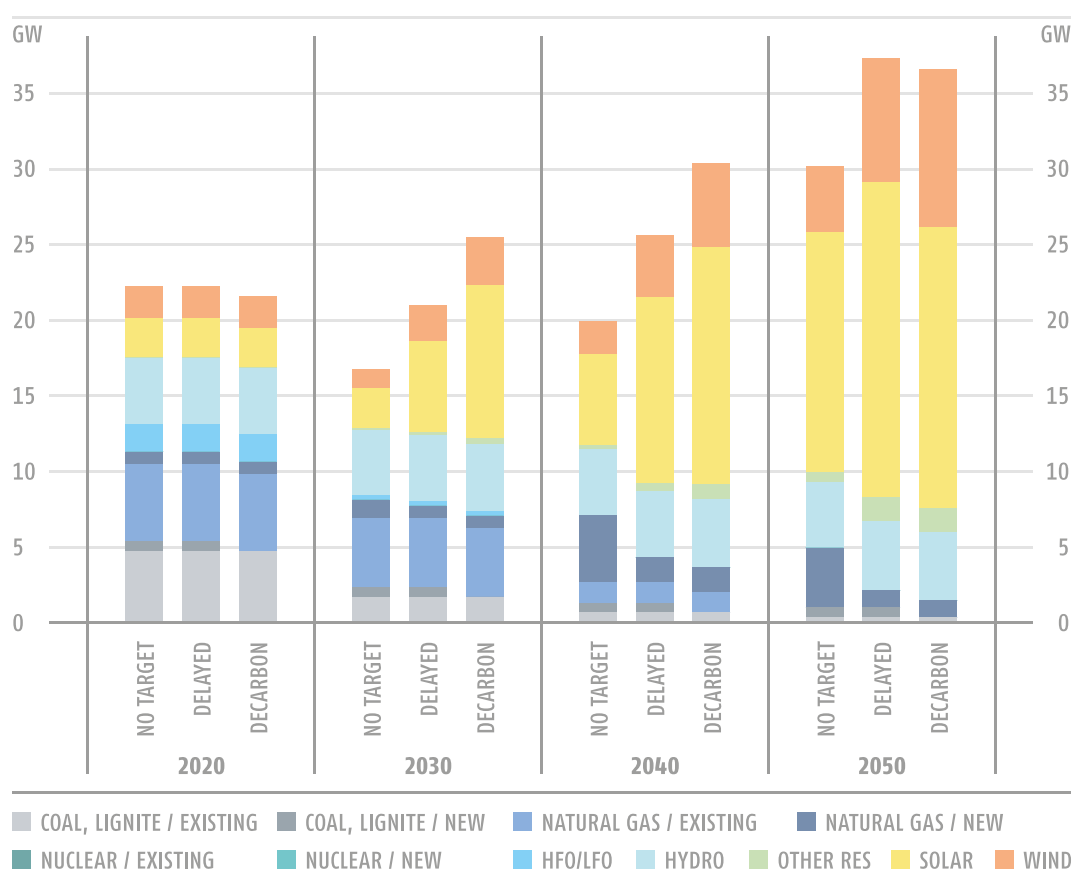
Annex 2 contains detailed information on the assumptions.

5 | Results

5.1 Main electricity system trends

The main investment challenge in Greece is replacing currently installed lignite and oil capacities. Approximately 40% of current fossil fuel generation capacity, more than 5000 MW, is expected to be decommissioned by the end of 2030, and 95% of current fossil generation capacity will be decommissioned by 2050.

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

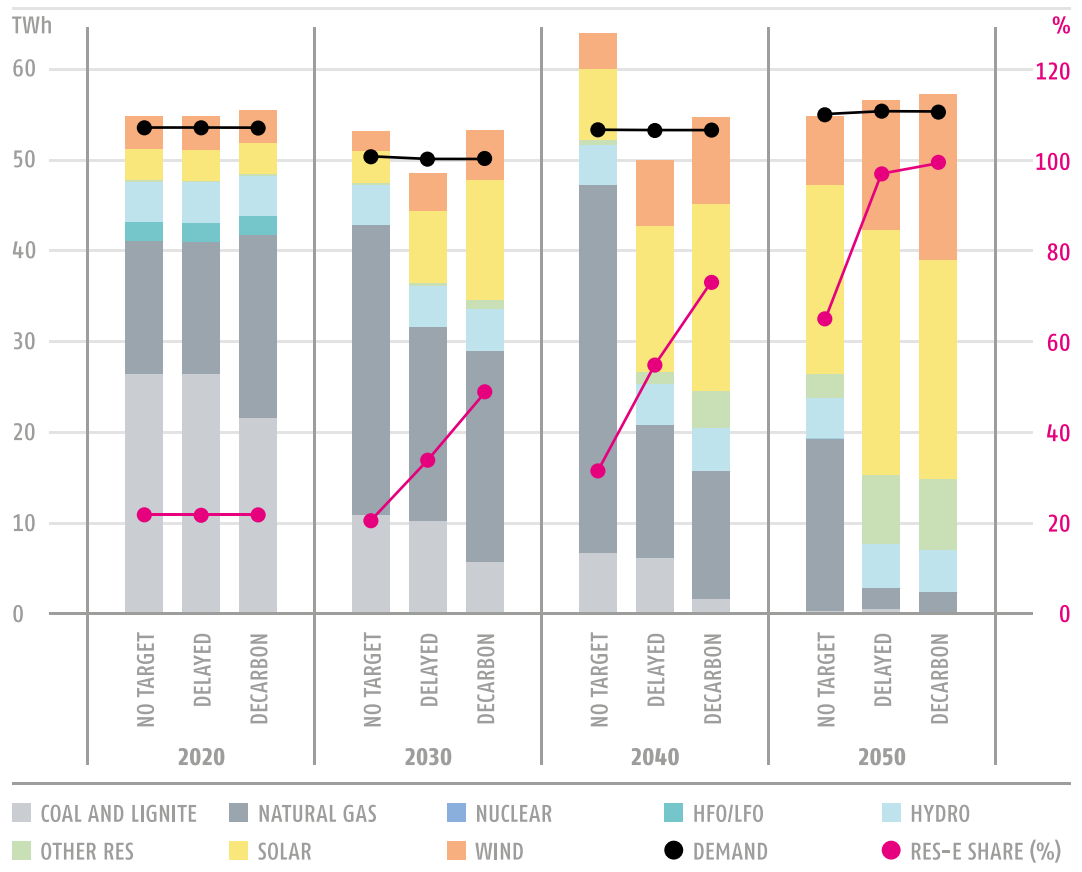


The model results show that in the scenarios with an emission reduction target the least cost capacity options are renewables (especially solar) under the assumed costs and prices, while in the 'no target' scenario a mix of natural gas and renewables is the least cost option. The generation mix changes significantly in all three scenarios, with a shift away from fossil fuels towards renewables. The change in the capacity mix is driven primarily by increasing carbon prices and decreasing renewable technology costs. Coal and oil based electricity generation disappear in all scenarios by 2050. While oil based electricity generation is phased out quickly, coal based electricity generation drops more slowly, becoming insignificant by 2050.

Renewables play an increasingly important role in all three scenarios. Major investments flow into solar capacities in Greece, due to a combination of high solar potential, decreasing cost of technology and the rising price of carbon. Investment in solar is further encouraged by small scale photovoltaic installations that compete against end-user electricity prices, whereas other renewables such as wind technology compete with the wholesale electricity price. New wind investment is also high in the 'delayed' and 'decarbonisation' scenarios towards the end of the modelled period, but total wind capacity decreases in the 'no target' scenario until 2035 thanks to capacity retirement and lack of new investment due to lack of support. Hydro capacity increases only by a small percentage over the entire period, and the share of biomass in the capacity mix increases but remains low in all three scenarios.

Natural gas plays a transitory role in electricity generation, peaking in 2035 in the 'no target' and 'delayed' scenarios and in 2025 in the 'decarbonisation' scenario. The initial increase in gas based electricity generation is driven by the carbon price, which prices out

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



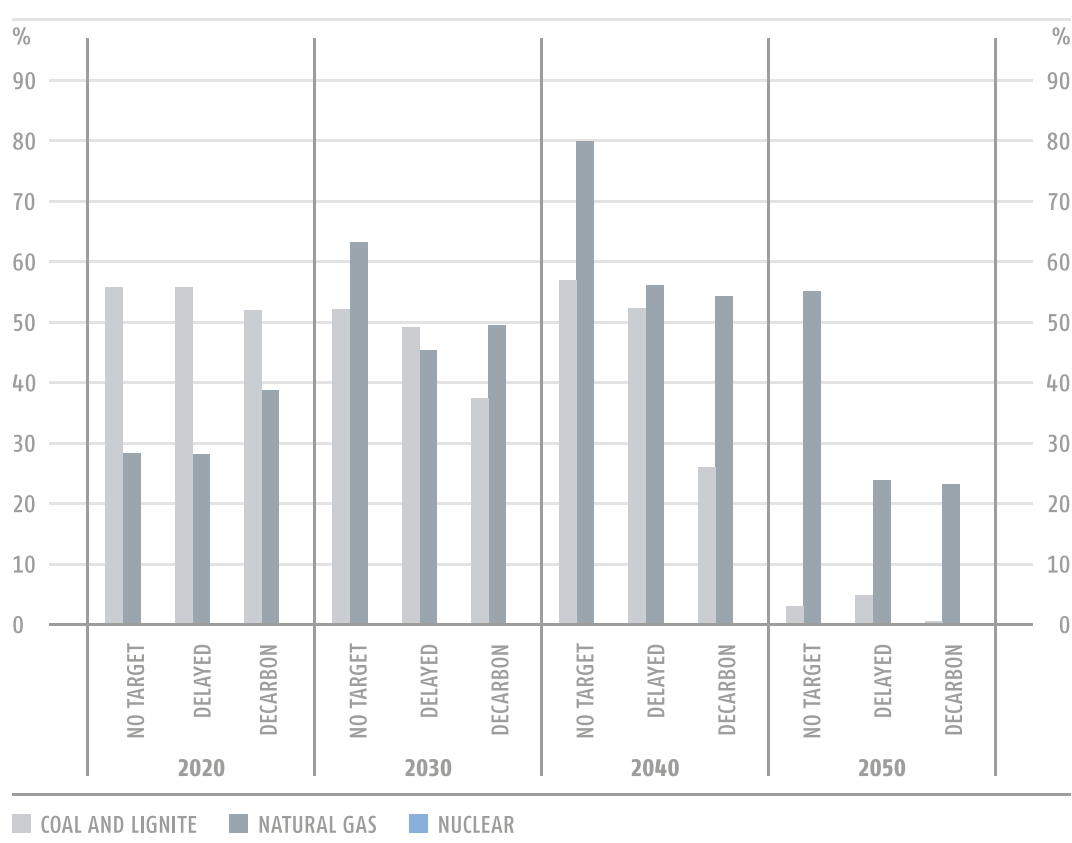
coal and lignite generation before sufficient renewable capacity is installed. Eventually, as the carbon and gas prices continue to rise and renewable technologies become cheaper, gas based generation declines.

In the 'no target' scenario investments in natural gas generation capacities are rather limited until 2030 when there is a 10 year uptick until 2040. The large increase in natural gas based generation is assisted by higher utilisation rates. Gas based electricity generation decreases between 2041 and 2050, but remains significant in 2050, being responsible for almost a third of electricity generation.

In the 'delayed' and 'decarbonisation' scenarios gas acts as a bridge fuel for only a short time period; it partially replaces coal and lignite generation on the path to decarbonisation until 2035. This can be achieved without a significant increase of natural gas capacities in these two scenarios, as the generation increase is due in large part to higher utilisation rates. Following the initial increase in natural gas based generation in these two scenarios, electricity generation from gas drops significantly by 2040 to around the same level in absolute terms as in 2020, continuing to slide to approximately 4% of total electricity generation by 2050.

In contrast to its present net import position, Greece becomes self-sufficient in electricity generation in all three scenarios. Stronger and faster growth in RES generation compared to some neighbouring countries (e.g. Bulgaria and former Yugoslav Republic of Macedonia) allows for this market development. Trade patterns are very volatile as minor price changes can alter the export/import positions of neighbouring countries, e.g. between Greece and Italy.

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



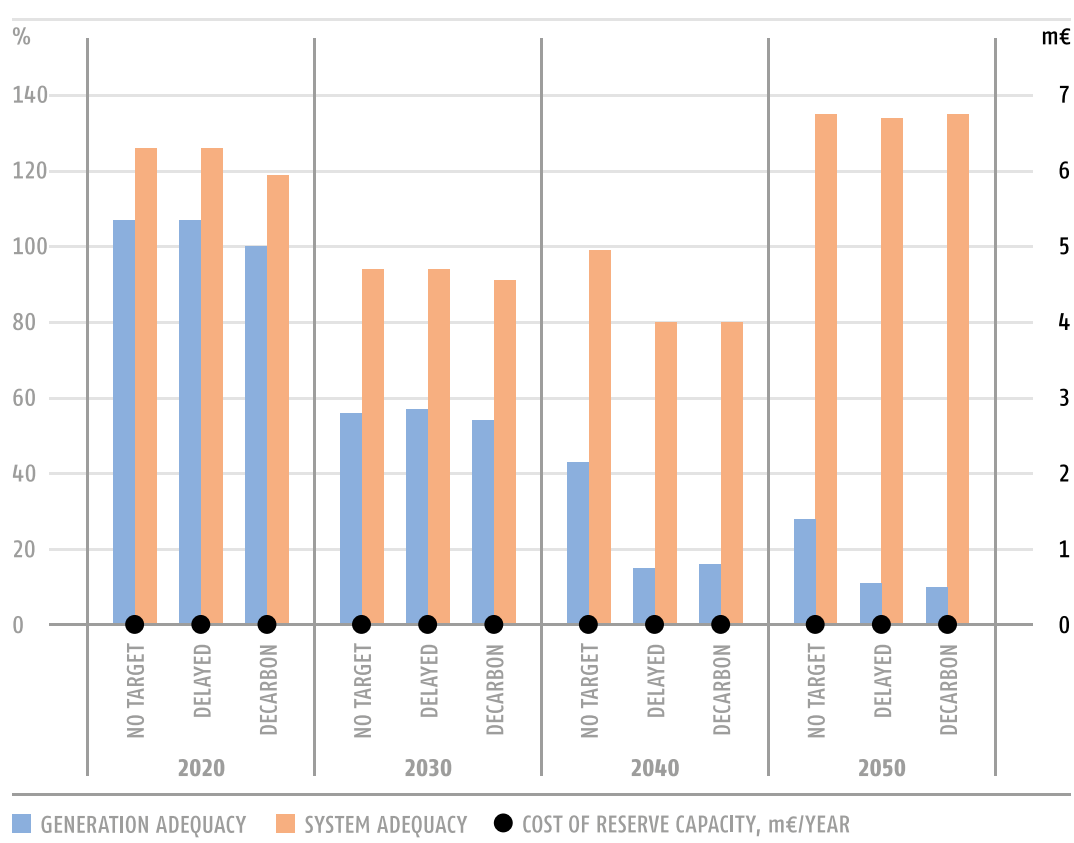
The utilisation rate of coal plants remains relatively stable until 2030 or 2040, depending on the scenario, but are far lower than current rates, which are typically above 70%. Utilisation rates drop below commercially viable levels by 2045, 2045 and 2030, in the 'no target', 'delayed' and 'decarbonisation' scenarios respectively. Gas utilisation rates are high, close to 50% or higher, for about two decades until 2045 in the two scenarios with a decarbonisation target, whereas in the 'no target' scenario utilisation rates increase, and remain high until 2050. This shows that if there is an ambitious decarbonisation target the cost of gas generation investments made at the beginning of the modelled period can be recovered but investments made closer to 2040 may be stranded. Coal investments made at any time during the modelled time period will result in stranded assets. This issue is discussed further in section 5.4.

5.2 Security of supply

While the physical and commercial integration of national electricity markets naturally improves security of supply, decision makers are often concerned regarding the extent and robustness of this improvement, in particular for energy systems with a high share of renewables. In order to assess the validity of these concerns three security of supply indices were calculated for all countries and scenarios: the generation capacity margin, the system adequacy margin, and the cost of reducing the generation adequacy gap 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, the load cannot be satisfied with domestic generation capacities alone in a given hour and imports are needed. The generation adequacy margin was calculated for all of the 90 representative hours and the lowest value was used as the indicator. For this calculation, assumptions

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



were made with respect to the maximum availability of different technologies. Fossil fuel power plants were assumed to be available 95% of the time, and hydro storage 100% of the time. For other RES technologies historical availability data was used. System adequacy was defined similarly but net transfer capacity available for imports is considered in addition to available domestic capacity. This is a simplified version of the methodology formerly used by ENTSO-E. (See e.g. ENTSO-E, 2015a, and previous SOAF reports)

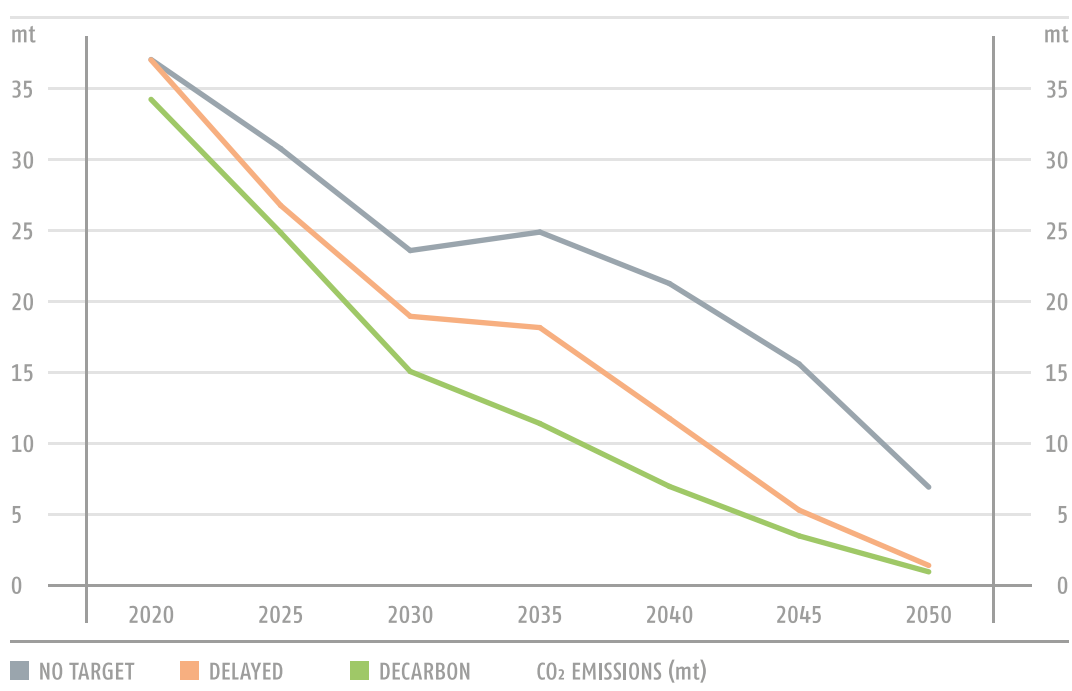
For Greece, the generation adequacy margin is positive throughout the modelling period, i.e. domestic generation capacity is sufficient to satisfy domestic demand in all hours of the year for all of the years modelled, however the value of the indicator decreases over time in all scenarios, the system adequacy margin is even higher.

For negative generation adequacy indicators the cost of reaching a zero generation adequacy margin was calculated. This is defined as the yearly fixed cost of an open cycle gas turbine (OCGT) which has adequate capacity to ensure that the generation adequacy margin reaches zero. This is a special form of capacity fee, assuming that capacity payments are only made to new generation, and that the goal of the payment is to improve the generation adequacy margin to zero. As the generation adequacy margin for Greece was positive to begin with for all years across all scenarios, this cost for Greece is zero.

5.3 Sustainability

The CO₂ emissions of the three core scenarios were calculated. Due to data limitations the CO₂ calculations for the three core scenarios did not account for other greenhouse gases and only considered direct emissions of electricity production, not including

FIGURE 7
CO₂ EMISSIONS
UNDER
THE 3 CORE
SCENARIOS
IN GREECE,
2020-2050 (mt)



emissions related to heat production from cogeneration. The calculations were based on representative emission factors for the region.

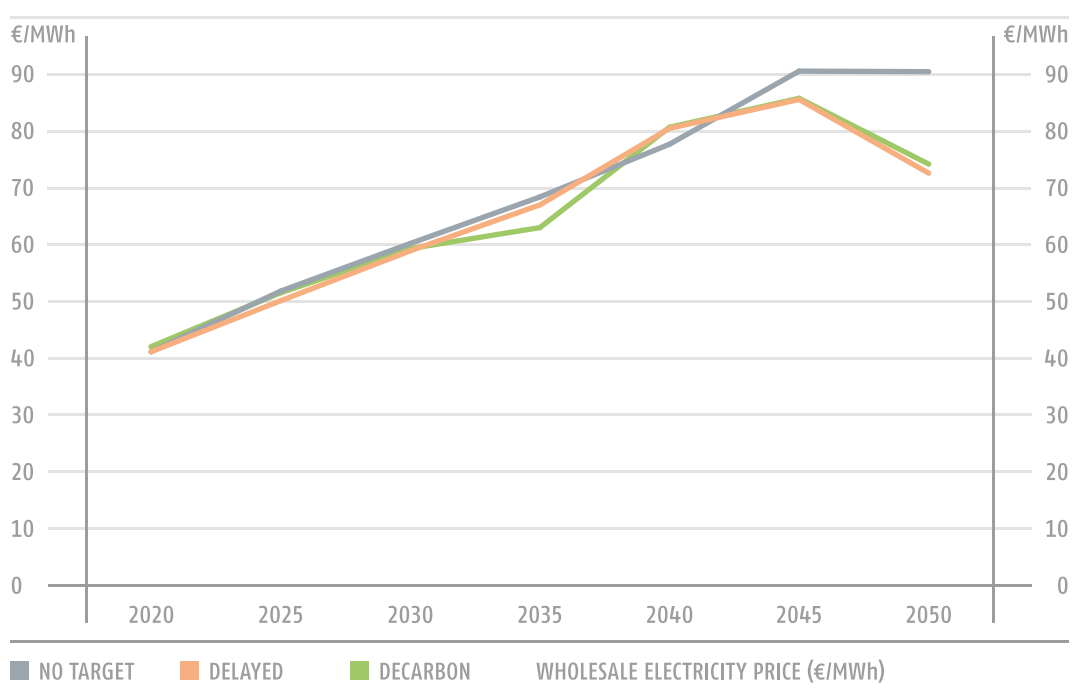
The 94% overall decarbonisation target for the EU28+WB6 region translates into a higher than average level of decarbonisation in the Greek electricity sector. By 2050 CO₂ emissions from the electricity sector in Greece compared to 1990 levels are reduced by 96.4% in the 'delayed' scenario and 97.6% in the 'decarbonisation' scenario, largely due to a relative advantage for renewable electricity production in Greece. As the WACC is relatively high in Greece compared with much of the EU, the relative advantage for Greece is the higher solar irradiation compared to more northern countries of the SEERMAP region. Emissions are also reduced significantly in the 'no target' scenario, dipping to 81.8% by 2050, driven by the high price of carbon and natural gas.

The share of renewable generation as a percentage of gross domestic consumption in 2050 is 64.6% in the 'no target' scenario, 97% in the 'delayed' scenario and 99.3% in the 'decarbonisation' scenario. In the scenario with the highest RES share in 2050 (the 'decarbonisation' scenario) long term RES potential utilisation reaches 33%, 68% and 64% for hydro, wind and solar respectively. This means that approximately two thirds of Greek wind and solar potential will be utilised by the end of the modelled period if this scenario is implemented.

5.4 Affordability and competitiveness

In the market model (EEMM) the wholesale electricity price is determined by the highest marginal generation cost of the power plants needed to satisfy demand. Over the modelled time period wholesale prices rise significantly, driven by an increasing carbon price and the price of natural gas. The price trajectories are independent from the level of decarbonisation and similar in all scenarios until 2045 when the two scenarios with a decarbonisation target result in lower wholesale prices. Nearing 2050, the share of low

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



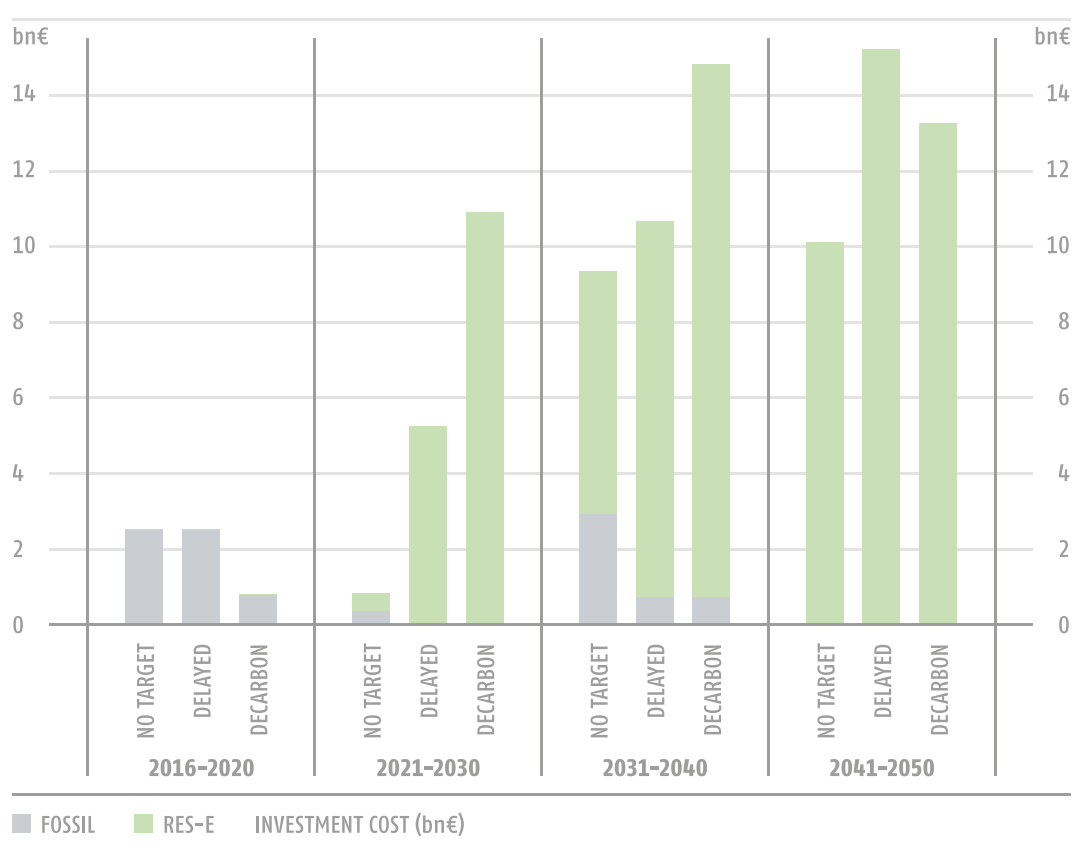
marginal cost renewables is high enough to satisfy demand in most hours at a low cost, driving the average annual price down.

The price development has several implications for policy makers. Retail prices depend on the wholesale price in addition to taxes, fees and network costs. It is therefore difficult to project retail price evolution based on wholesale price information alone, but it is likely that an increase in wholesale prices will affect affordability for consumers since it is a key determinant of the end user price. The average annual price increase over the entire period is 2.7% in the 'no target' scenario, 2.0% in the 'delayed', and 2.1% in the 'decarbonisation' scenario; the lower growth rate in the latter two scenarios is attributable to a decrease in the wholesale price during the last 5 years of the modelled time period. Although the price increase is significant, it is important to note that at the beginning of the analysis in 2016 wholesale electricity prices in Europe are at historical lows, and furthermore the analysis projects wholesale prices to increase to approximately 60 EUR/MWh by 2030 which is the price level from 10 years ago. Assessing macroeconomic outcomes in section 5.7 – if affordability is measured as household electricity expenditure as a share disposable income – electricity remains affordable even with the price increase. Besides its negative impacts, the price increase also has three positive implications, incentivising investments in new capacities, helping energy efficiency improvements, and reducing the need for RES support.

The investment needed in new capacities increases significantly over the entire modelled time period. Investment is particularly high in the 'decarbonisation' scenario between 2030 and 2040 and in the 'delayed' scenario between 2040 and 2050, reflecting the significant requirements for meeting decarbonisation targets at the end of the period. Meanwhile, investment needs are lowest in the 'no target' scenario from 2020 throughout the entire modelling period.

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

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



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

Despite the high investment requirements associated with the two emission reduction target scenarios, the renewables support needed to incentivise these investments decreases over time. RES support relative to the wholesale price plus RES support in the 'decarbonisation' scenario is 25% in the period 2020-2025 but only 6% in 2045-2050. Although some RES technologies have reached grid parity in some areas with technology costs continuing to fall, some support will still be needed in 2050 to stimulate new investment. This is because the best locations with highest potential are used first, and the levelised cost of electricity of new capacities therefore increases if more capacity is already installed. The relationship between the cost of RES technologies and installed capacity is shown in figure 10, but does not account for the learning curve adjustments which were embedded in the Green-X model.

Over the entire period RES support decreases while investment in RES capacity increases, with the exception of the last decade in the 'delayed' scenario, where a very significant investment effort is needed in renewables and this requires high levels of RES support. The broad decline in RES support is made possible mainly by the increasing wholesale price for electricity which reduces the need for residual support.

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

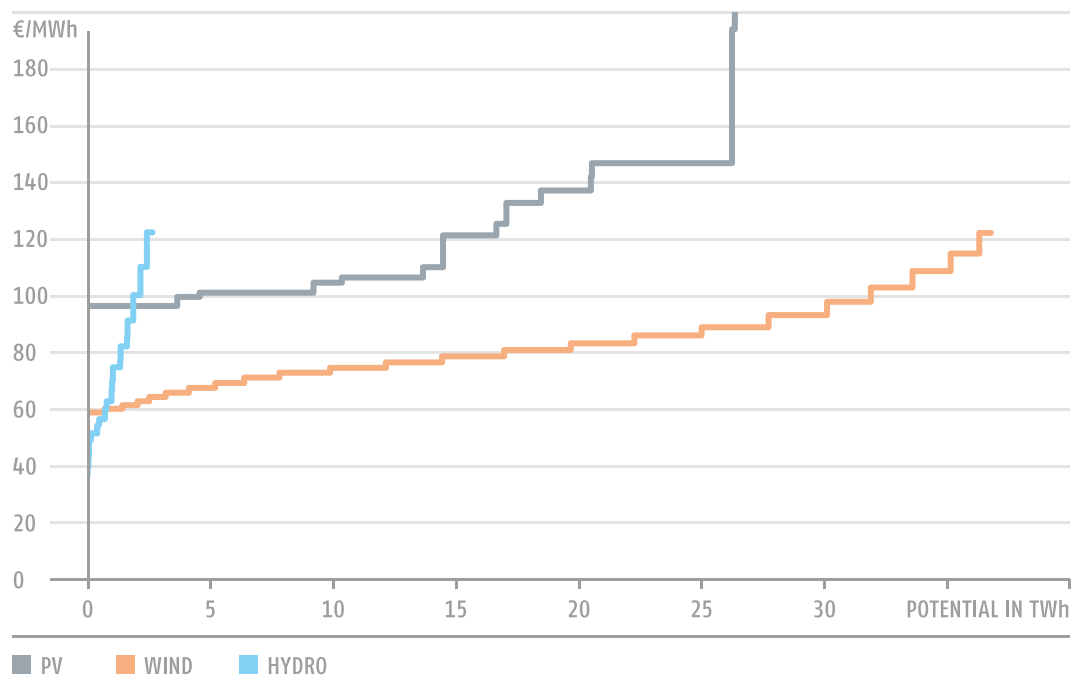


FIGURE 11
AVERAGE
RES SUPPORT
PER MWh
OF TOTAL
ELECTRICITY
CONSUMPTION
AND AVERAGE
WHOLESALE
PRICE,
2016-2050
(€/MWh)

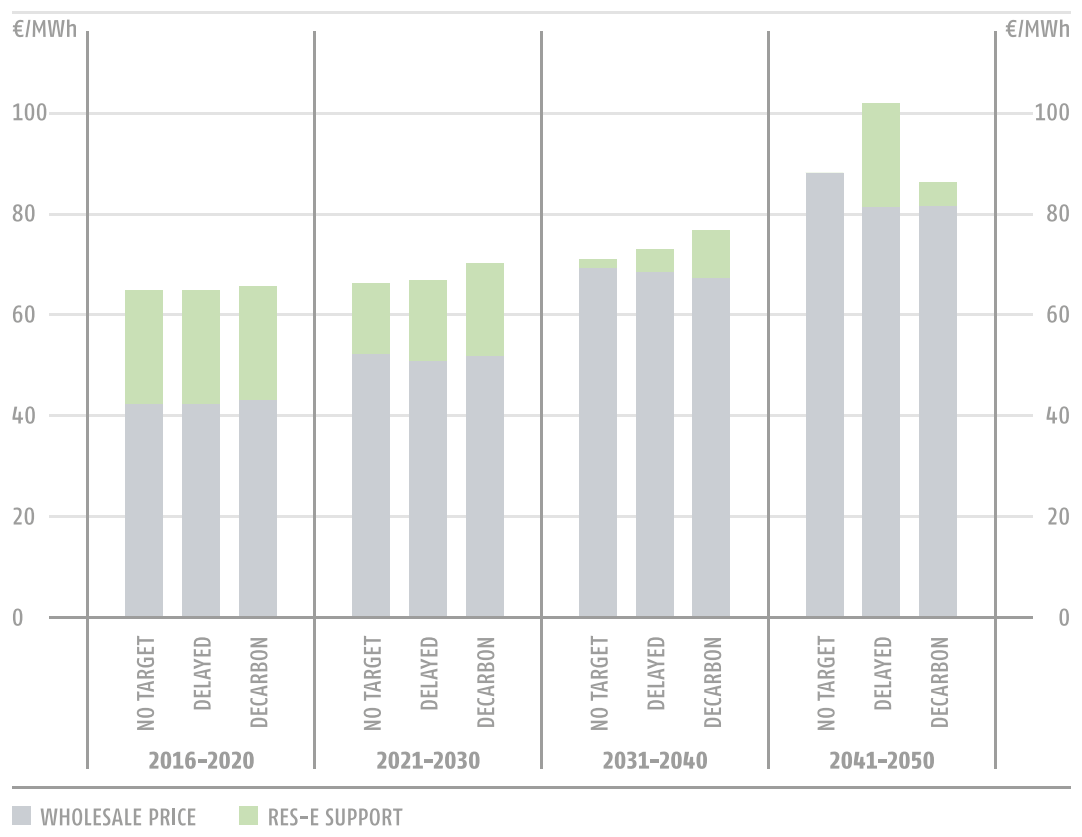
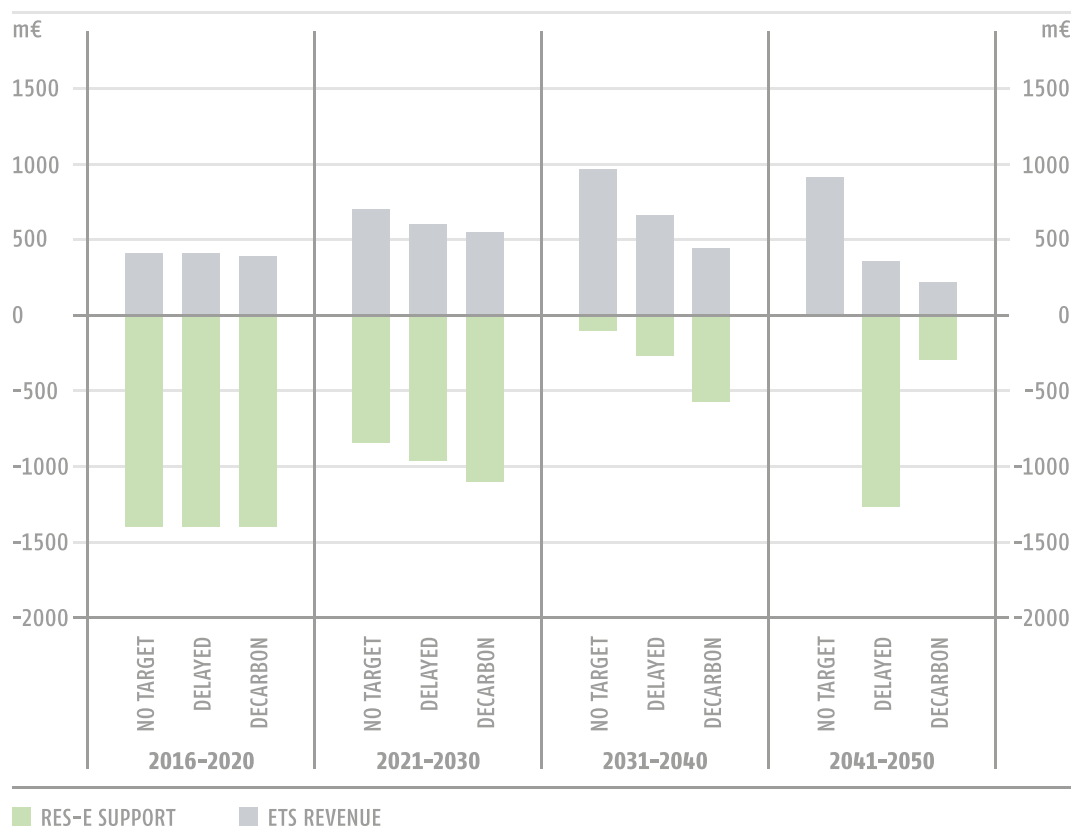


FIGURE 12
CUMULATIVE
RES SUPPORT
AND AUCTION
REVENUES FOR 4
AND 10 YEAR
PERIODS,
2016-2050 (m€)



Renewable energy investments may be incentivised through a variety of support schemes that secure funding from different sources, and in the model 'sliding' feed-in premium equivalent values are calculated. Revenue from the auction of carbon allowances under the EU ETS is one potential source of financing for renewable investment. Figure 12 compares cumulative RES support needs with ETS auction revenues, under an assumption of 100% auctioning and taking into account only allowances used in the electricity sector. In the 'decarbonisation' and 'delayed' scenarios, auction revenues decrease significantly by the end of the modelled time period because fossil plants paying for their emissions mostly disappear from the Greek capacity mix. Overall the modelling results show that ETS revenues can cover a significant portion of the necessary support between 2021 and 2030, and most of the necessary support in the following decade. In all scenarios the required RES support is significantly higher than ETS revenues in the period of 2016-2020. This is also the case in the 'delayed' scenario between 2041 and 2050.

A financial calculation was carried out to determine the stranded costs of fossil generation plants that are built in the period 2017-2050. New fossil generation capacities included in the scenarios are defined either exogenously by national energy strategy documents or are built by the investment algorithm of the EEMM endogenously. The investment module projects 10 years ahead, meaning that investors have limited knowledge of the policies applied in the distant future. By 2050, the utilisation rate of coal generation assets drops below 15% and gas generation below 25% in most SEERMAP countries in the 'delayed' and 'decarbonisation' scenarios. This means that capacities which generally need to have a 30-55 year lifetime (30 for CCGT, 40 for OCGT and 55 for coal and lignite plants) with a sufficiently high utilisation rate in order to ensure a positive return on investment will face stranded costs.

Large stranded capacities will likely require public intervention, whereby costs are borne by society/electricity consumers. Therefore, the calculation assumes that stranded costs will be collected as a surcharge on the consumed electricity (as is the case for RES surcharges) over a period of 10 years after these gas and coal capacities finish their operation. Based on this calculation early retired fossil plants would have to receive 3.9 EUR/MWh, 3.6 EUR/MWh and 1.4 EUR/MWh surcharge over a 10 year period to cover their economic losses in the 'no target', 'delayed' and 'decarbonisation' scenarios respectively. These costs are not included in the wholesale price values shown in this report. The cost of stranded investments is reduced by more than 50% from 2089 mEUR in the 'no target' scenario to 739 mEUR in the 'decarbonisation' scenario.

5.5 Sensitivity analysis

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

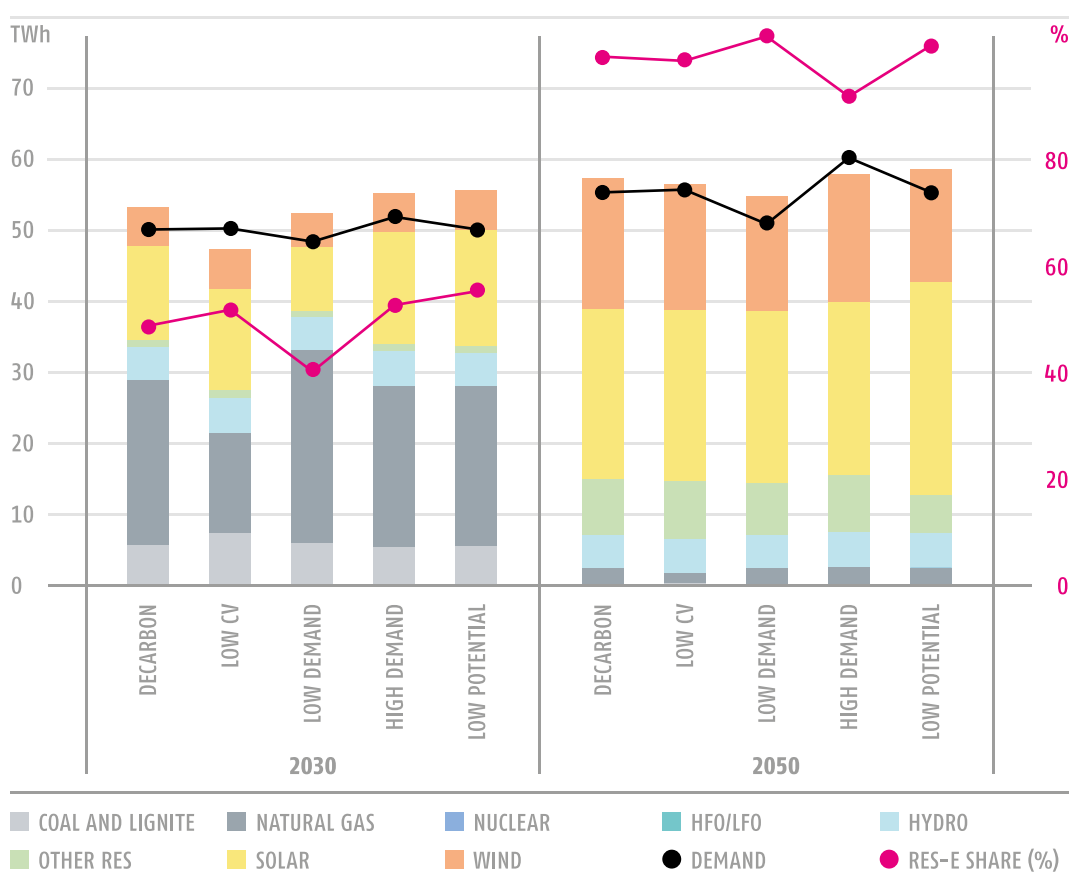
- Carbon price: to test the impact of a lower CO₂ price, a scenario was run which assumed that CO₂ prices would be half of the value assumed for the three core scenarios for the entire period until 2050;
- Demand: the impact of higher and lower demand growth was tested, with a +/-0.25% change in the 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 adjustments were only applied to the 'decarbonisation' scenario since this is the scenario that represents a significant departure from current policy for many countries. Therefore, it is important to test the robustness of results in order to convincingly demonstrate that the scenario could realistically be implemented under different framework conditions.

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

- The CO₂ price is a key determinant of wholesale prices. A 50% reduction in the value of the carbon price results in an approximately 25% reduction in the wholesale price over the long term. However, this wholesale price reduction is more than offset by the need for higher RES support. This is the scenario with the second highest sum of the wholesale price and RES support.
- A lower carbon price would increase the utilisation rates of coal power plants by 11% in 2030 and by 10% in 2050. However, this is not enough to make coal competitive by 2050 as significantly higher utilisation rates are required to avoid plant closure.
- Gas utilisation rates fall with lower carbon prices.
- Change in demand has only a limited impact on fossil fuel capacities and generation. RES capacity and generation, notably PV and wind, are more sensitive to changes in demand.
- Lower hydro and wind potential results in increased PV capacity and generation.

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



5.6 Network

Greece's transmission system is already well-connected with its neighbouring countries. In the future additional network investments are expected to be realised to accommodate higher RES integration and cross-border electricity trade and to account for significant growth in peak load. The recorded peak load for Greece in 2016 was 9,207 MW (ENTSO-E DataBase), while it is projected to be 9,900 MW in 2030 (SECI DataBase) and 11,000 MW in 2050. Consequently, domestic high and medium voltage transmission lines and distribution lines will need investment.

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

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

- **Contingency analysis:** Analysis of the network constraints anticipates contingencies at the Southern Aegean Interconnector. These problems could be solved by heavy investments in the Aegean network, where costs are estimated by the Greek TSO to be around 1800 mEUR.

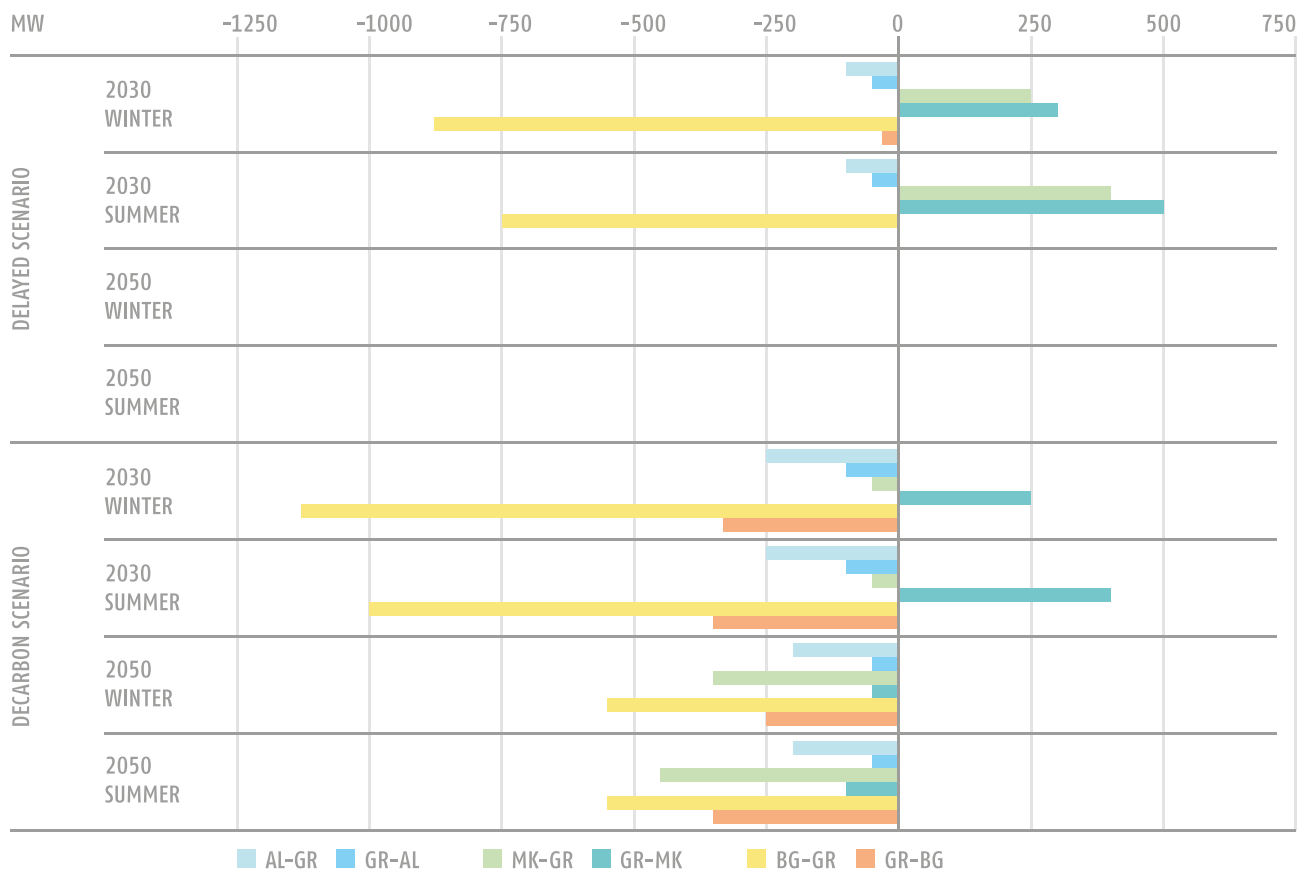


FIGURE 14
NTC VALUE
CHANGES
IN 2030
AND 2050 IN
THE 'DELAYED'
AND 'DECAR-
BONISATION'
SCENARIOS
COMPARED
TO THE
'BASE CASE'
SCENARIO

TABLE 1 | OVERLOADINGS IN THE GREEK SYSTEM, 2030

Overloading	Solution	Units (km or pcs)	Cost m€
Southern Aegean Interconnector (GR) AC submarine cables (150 kV or 220 kV)	2 converter SS + 270 km DC submarine. Cable Connection Wind Farms with AC Substations at Levitha and Syrna AC Submarine cable to connect Kinaros Offshore Wind Farm HiV sub station to the AC side of Levitha Converter SS	several HVDCs	1 800.00

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

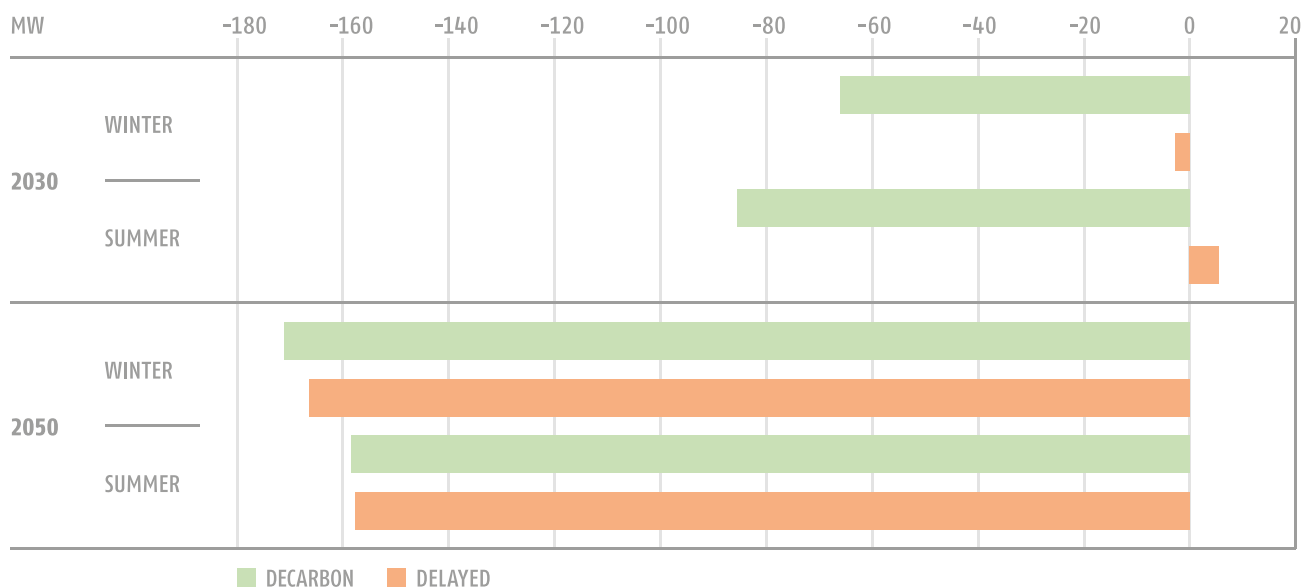


FIGURE 15
LOSS VARIATION
COMPARED TO
THE BASE CASE
IN THE 'DELAYED'
AND 'DECAR-
BONISATION'
SCENARIOS
(MW, NEGATIVE
VALUES
INDICATE LOSS
REDUCTION)

- As the results show, NTC values decrease in the RES intensive 'decarbonisation' and 'delayed' scenarios, with the exception of the 2050 'delayed scenario' values compared to the 'base case' scenario. This shows that the 'congestion' impact of RES is stronger in Greece than the import substitution effect. The most affected direction is the BG-GR relation.
- Network losses:** Transmission network losses are affected in different ways. For one, losses are reduced as renewables, especially PV, are mostly connected to the distribution network. However, the increasing volume of electricity trade in the modelled period will increase transmission network losses.

As figure 15 illustrates, the higher RES deployment in the two scenarios reduces transmission losses to a significant extent to around 80 MW in 2030 and 160 MW in 2050 for the modelled hours. This represents a 270 GWh loss variation in 2030 and over 600 GWh in 2050. If monetised at the base-load price, the concurrent benefit for TSOs is over 40 mEUR per year.

Overall, a significant amount of investment in the transmission and distribution network is necessary to accommodate new RES capacities in the Greek electricity system. Most of the investment is related to the distribution network (in association with solar generation capacity) but some is also required in the transmission network before 2030. In its 2017-2026 TYNDP, the Greek TSO estimated the total cost of network investments to be around 1800 mEUR. This includes not only the transmission network costs (i.e. submarine DC transmission links to connect the Cyclades islands of the Aegean Sea to mainland Greece and the islands of Crete by 2025), but the necessary connecting facilities and reinforcement of the national grid to facilitate the expected increase in RES generation.

5.7 Macroeconomic impacts

A 'baseline' scenario which differs from the three core scenarios was constructed for the macroeconomic analysis, to serve as a basis for comparison. The 'baseline' scenario

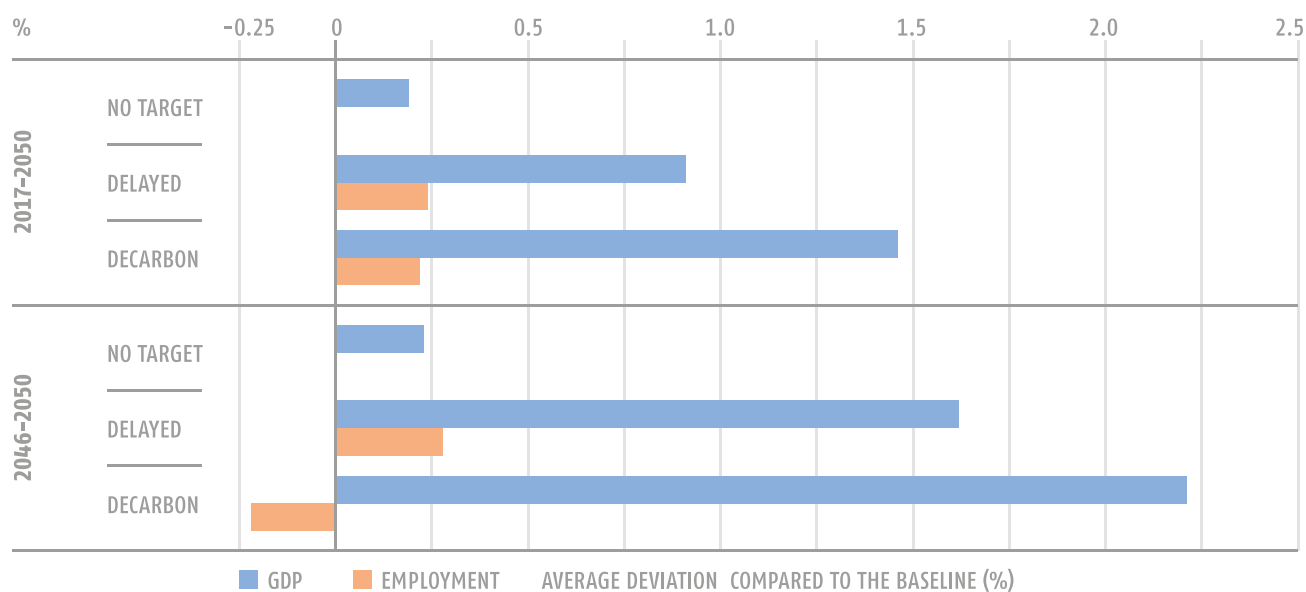


FIGURE 16
GDP AND
EMPLOYMENT
IMPACTS
COMPARED WITH
THE 'BASELINE'
SCENARIO

assumes that only power plants with a final investment decision by 2016 are built and that investment rates in the sector remain unchanged for the remaining period. No 'decarbonisation' targets are set in this case, and no additional renewable support is assumed compared to currently existing policies. The 'baseline' scenario assumes lower levels of investment than the three core scenarios.

The 'baseline' scenario for Greece envisages moderate economic growth of 1.2% per annum until 2050. This is due to the extremely high initial public and external debt levels and the fact that Greece is the most developed country in the SEERMAP region. After an initial uptick in employment arising from recovery and structural reforms, it is expected to broadly stagnate. Both government and external debt will decline throughout the modelled horizon and will reach around 100% of GDP by 2050, starting from extremely high initial levels. This means that the macroeconomic position of the country will remain an important source of vulnerability throughout the entire modelling horizon.

The 1.8% household electricity expenditure to income is currently much lower (roughly half) compared to other countries in the region mostly due to the higher economic development level of the country. The baseline scenario results show that this ratio will deteriorate over time.

All three core scenarios imply a moderate increase in investment compared to the 'baseline' scenario. Even in the most investment intensive periods, the additional investment is below 0.5% of GDP. In the 'no target' scenario, most of the additional investment compared with the 'baseline' scenario is concentrated before 2020, while in the 'decarbonisation' scenario the investment intensive period starts after 2020 and remains relatively persistent. In the 'delayed' scenario there are two investment peaks, from 2021-2025 and between 2036-2040.

The macroeconomic results were assessed 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

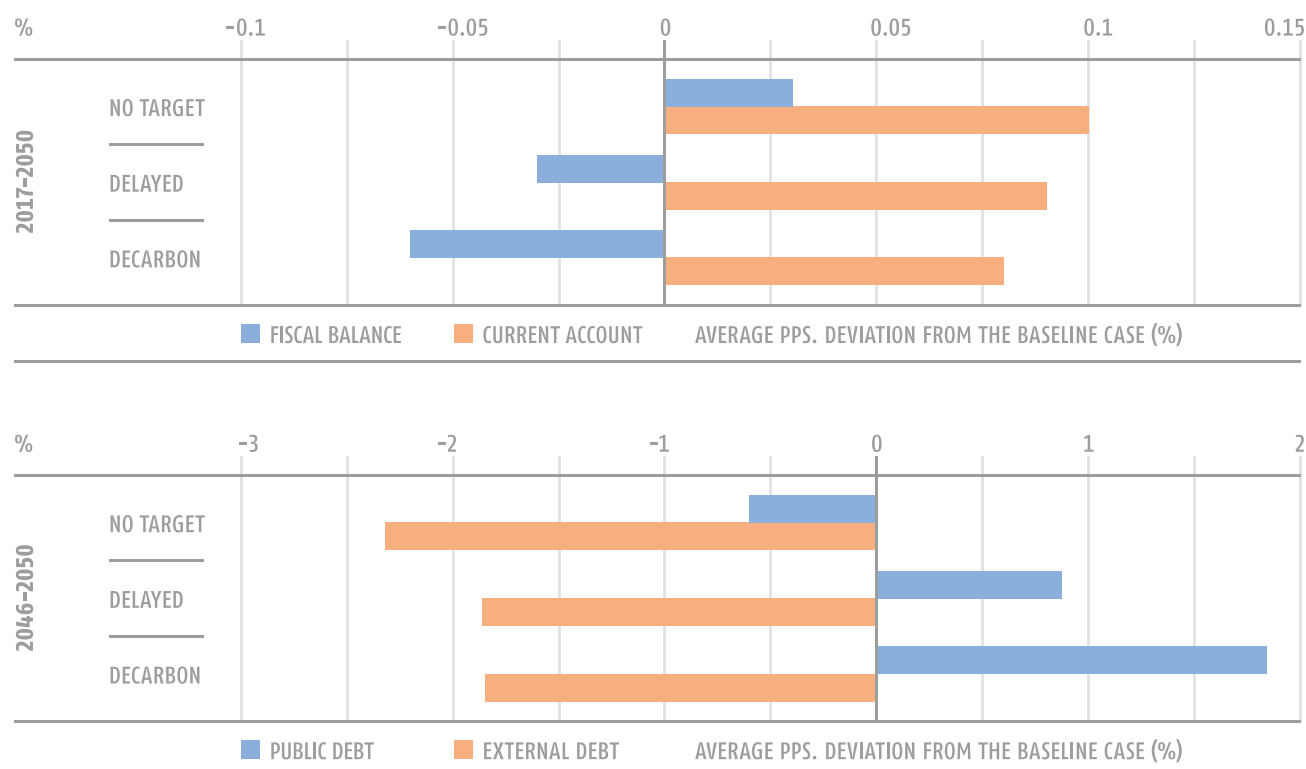


FIGURE 17
PUBLIC AND
EXTERNAL
BALANCES AND
DEBT IMPACTS
COMPARED WITH
THE 'BASELINE'
SCENARIO

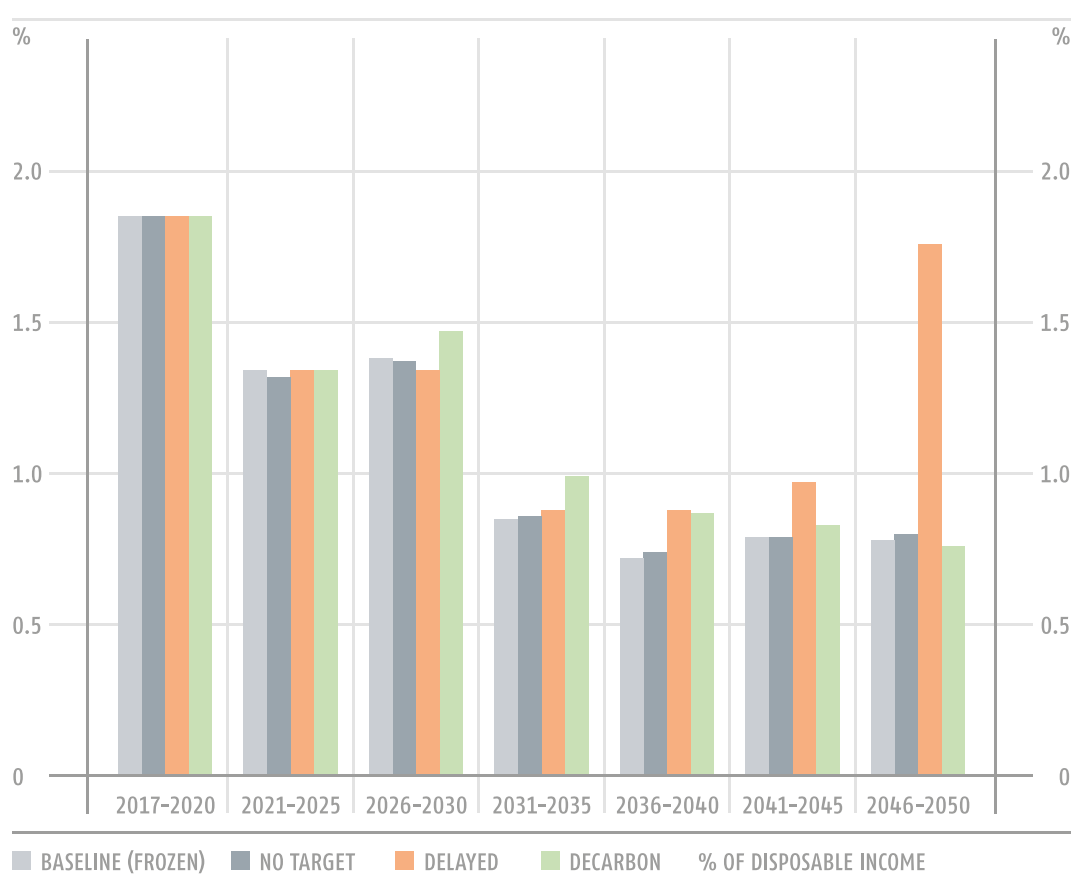
the whole time horizon (2016-2050) is compared with the baseline. Then the long term effect is determined by the deviation from the baseline in the 2046-2050 period. It is important to stress that because the population remains the same across scenarios GDP gains also reflect GDP per capita effects.

Overall, the results for Greece suggest moderate macroeconomic gains from the three core energy investment intensive scenarios compared with the baseline. In the 'decarbonisation' scenario, the GDP level is on average 1.5% higher until 2050 than in the 'baseline' scenario. The long term GDP effect is slightly higher at 2%. Gains are somewhat more moderate in the 'delayed' scenario (at around 0.9% on average and 1.5% in the long term, by 2045-2050) and practically zero in the 'no target' scenario. Employment effects are very muted in the 'decarbonisation' and 'delayed' scenarios at around 0.2% on average compared to the 'baseline' scenario, and these gains disappear over the long term. At the same time, the 'no target' scenario has practically no visible effect on employment.

Long term GDP gains in the 'decarbonisation' and 'delayed' scenarios result from two sources. The additional investment raises the level of productive capital in the economy and the newly installed, mostly foreign technologies increase overall productivity. 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. This aspect is analysed by looking at the fiscal and the external balances, as well as

FIGURE 18
HOUSEHOLD
ELECTRICITY
EXPENDITURE
2017-2050



the public and external debt indicators. While we compare the fiscal and the external balances to the 'baseline' scenario over the whole projection horizon (2017-2050), in case of the debt indicators, we concentrate on the long term effects, and calculate the difference from the baseline only at the end of the modelled time horizon. This approach is consistent with the fact that debt is accumulated from past imbalances.

The three core scenarios slightly decrease the macroeconomic vulnerability of Greece. The change in public debt levels is negligible, while external debt levels exhibit a decrease – by 2% of GDP in the long term. Declining external debt is the primary result of an improving current account due to lower gas imports compared to the baseline. The core scenarios have a small effect on the fiscal balance primarily due to differences in ETS auction revenues.

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

The core scenarios do not differ significantly from the baseline with exception of the 'delayed' scenario. In the 'delayed' scenario, household expenditure on electricity increases very significantly compared to the baseline towards the end of the modelled period, primarily due to the large increase in renewable support at the end of the period. Nonetheless, electricity expenditure to income still stands at a slightly lower level at the end of the period than the beginning. In the other scenarios, no major change could be observed relative to the baseline.

6 | Policy conclusions

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

MAIN POLICY CONCLUSIONS

Regardless of whether or not Greece pursues an active policy to decarbonise its electricity sector a significant shift away from fossil fuels to renewables will take place:

- Due to aging power plants Greece will need to replace approximately 95% of its existing conventional generation fleet by 2050;
- Lignite electricity generation will comprise around 10% or less by 2040 and disappear by 2050;
- Natural gas plays a transitional role on the path towards low carbon generation;
- The high penetration of RES across all scenarios suggests that Greek energy policy should focus on enabling RES integration;

Decarbonisation is worth it:

- Current policies and trends are not in line with the deep electricity sector decarbonisation share of 93-99% envisioned in the EU Roadmap 2050;
- The 'decarbonisation' scenario demonstrates that it is technically feasible and financially viable for Greece to reach 97% emission reduction with its abundant RES resources;
- Decarbonisation does not drive up wholesale prices relative to other scenarios with less ambitious RES policies and actually reduces them after 2045;
- The macroeconomic analysis shows that despite the high absolute increase in wholesale prices, household electricity expenditure relative to household income is expected to increase only slightly compared with current levels, and will decrease compared with the 'baseline';
- Decarbonisation reduces the cost of stranded investments by more than 50% from 2089 mEUR to 739 mEUR;
- The 'decarbonisation' scenario enables Greece to significantly reduce its reliance on imported fossil fuels over the long term, especially natural gas;
- Decarbonisation will require a significant increase in investment needs from about 22 bn EUR to about 38-39 bn EUR over the 35-year period:
 - ▶ As this will be covered by private investment, it will have a positive effect on GDP growth by about 1.5% on average and a small positive effect on employment over the assessed period;
 - ▶ Increased investment needs are counterbalanced by reduced fossil fuel imports resulting in a negligible positive net effect on the fiscal balance and current account;
 - ▶ External debt falls around 2% over the long term.

6.1 Main electricity system trends

In Greece, approximately 40% of current fossil fuel generation capacity, more than 5000 MW, is expected to be decommissioned by the end of 2030, and 95% of current generation capacity will be decommissioned by 2050. This provides both a challenge in terms of the need to ensure a policy framework which will result in the necessary new investment, but also an opportunity to shape the electricity sector over the long term without being constrained by the current capacity mix.

Whether or not Greece pursues an active policy to support renewable electricity generation, fossil fuel generation capacity will decline precipitously driven by the price of carbon; coal, lignite and oil are phased out under all scenarios by 2050, but the decline in the share of these fuels begins much earlier, with around 10% or less coal based generation as a share of the electricity mix in 2040 in all scenarios. Oil is phased out even earlier.

With ambitious decarbonisation targets and corresponding RES support schemes, Greece will have an electricity mix with close to 100% renewable generation – mostly solar and wind and some hydro – by 2050. Absent a CO₂ emission reduction target and with renewable subsidies phased out under the ‘no target’ scenario, the share of RES in electricity consumption will reach approximately 65% in 2050. This will represent a significant increase on current levels.

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

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

Natural gas will remain a relevant fuel source over the coming decades, increasing in all scenarios initially. However, the role of natural gas is transitory in a scenario with a decarbonisation target of 93-99%, playing only a very minor role by 2050. In the ‘decarbonisation’ scenario new gas capacity is installed to replace outgoing capacity, but there is no need for a significant capacity increase to bridge the transition from fossil fuel to renewable based electricity mix – higher gas based generation is realised with higher utilisation rates. Under the ‘no target’ scenario gas remains relevant in 2050 but gas based generation peaks in 2035.

The role for gas under the ‘decarbonisation’ and ‘delayed’ scenarios, the two scenarios in line with EU climate policy goals, is limited. If significant investments are made in gas based generation and infrastructure (as well as in coal based generation) it can result in stranded assets. Decarbonising the electricity sector with long term emission reduction targets in mind, as demonstrated by the ‘decarbonisation’ scenario, avoids stranded costs in fossil based generation but brings new challenges for high RES penetration and increased investment needs.

Delayed action in the rollout of renewables is feasible but carries two significant disadvantages compared with a long term planned effort. It results in stranded fossil fuel generation assets, including currently planned power plants. Translated into a price equivalent over a 10 year period, the cost of stranded assets is on par with the size of RES support needed for decarbonising the electricity sector. Assuming delayed action,

the disproportionate push towards the end of the modelled period to meet the CO₂ emission reduction target requires significant increases in RES support.

6.2 Security of supply

In both scenarios with a decarbonisation target, Greece produces approximately the same amount of electricity as it consumes throughout the modelling period; in the 'no target scenario Greece is a net electricity exporter over a two decade period. Its generation and system adequacy indicators also remain favourable; installed generation capacity within the country enables Greece to satisfy domestic demand using domestic generation in all seasons and hours of the day for the entire modelled period.

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

The 'decarbonisation' scenario enables Greece to significantly reduce its reliance on imported fossil fuels including natural gas by the end of the modelled period, while achieving a diversified supply mix.

The network modelling results suggest that Greece would have to invest in the transmission and distribution network and cross-border capacity. Significant investment is needed in the Greek network system – estimated by the Greek TSO in the range of 1800 mEUR.

6.3 Sustainability

Greece has high renewable potential, especially solar, relative to the EU and the SEE region average, allowing Greece to make an above average contribution to 2050 emission reduction targets. In Greece CO₂ emissions in the electricity sector fall by 96.4% in the 'delayed' and 97.6% in the 'decarbonisation' scenarios compared with the 94% target set for the EU28+Western Balkans region as a whole. The high RES and CO₂ emission reduction potential is an asset for Greece.

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

6.4 Affordability and competitiveness

Decarbonising the electricity sector does not drive up wholesale electricity prices compared to a scenario where no emission reduction target is set. The wholesale price of electricity is not driven by the level of decarbonisation but by the CO₂ price, which is applied across all scenarios, and the price of natural gas, because the latter is the marginal production needed to meet demand in a significant number of hours of the year for much of the modelled time period in all scenarios.

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

All scenarios demonstrate a significant increase in the wholesale electricity price compared with current (albeit historically low) price levels. This trend is observable across the SEE region and the EU as a whole in all scenarios for the modelled time period and

is driven by the price of carbon and the price of natural gas, both of which increase significantly by 2050. While higher wholesale prices will reach end consumers, it is an important signal for attracting investment to replace retiring capacity. **The macroeconomic analysis shows that despite the high absolute increase in wholesale prices, household electricity expenditure is expected to decrease relative to household income as the effect of RES support and declining energy intensity overcompensates the effect of increasing wholesale prices.**

Decarbonisation will necessitate a very significant increase of investment in generation capacity. These investments are assumed to be financed by private actors who accept higher investment costs in exchange for low operation (including fuel) and maintenance costs. From a broad societal point of view, the swell of investment boosts GDP and has a small but positive impact on employment. At the same time, the external debt decreases by 6-8% of GDP in the long term owing to lower electricity and gas imports compared with the 'baseline' scenario.

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

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

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

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Annexes

Annex 1 | Model output tables

TABLE A1 | 'NO TARGET' SCENARIO

			2016	2020	2025	2030	2035	2040	2045	2050
Installed capacity, MW	Coal, lignite	Existing	4 736	4 736	2 624	1 714	1 315	685	375	375
		New	0	660	660	660	660	660	660	660
	Natural gas	Existing	5 081	5 081	5 081	4 521	3 243	1 333	334	0
		New	0	845	845	1 245	3 245	4 445	4 445	3 934
	Nuclear	Existing	0	0	0	0	0	0	0	0
		New	0	0	0	0	0	0	0	0
	HFO/LFO		2 019	1 835	1 370	284	284	0	0	0
	Hydro		3 449	4 329	4 343	4 357	4 371	4 385	4 354	4 322
	Wind		2 298	2 111	1 752	1 307	1 122	2 230	3 159	4 376
	Solar		2 615	2 615	2 615	2 614	2 623	6 008	11 725	15 837
	Other RES		56	72	81	93	103	230	400	704
Gross consumption, GWh			51 440	53 593	52 027	50 423	52 508	53 350	53 816	55 073
Net electricity generation, GWh	Total		47 543	54 897	58 798	53 206	61 633	63 962	63 979	54 891
	Coal and lignite		21 572	26 370	16 751	10 863	9 075	6 710	3 691	271
	Natural gas		11 798	14 666	29 220	31 961	42 468	40 465	33 818	19 020
	Nuclear		0	0	0	0	0	0	0	0
	HFO/LFO		2 105	2 105	1 684	0	0	0	0	0
	Hydro		4 459	4 459	4 459	4 459	4 459	4 459	4 459	4 459
	Wind		4 034	3 706	3 076	2 294	1 970	3 914	5 547	7 682
	Solar		3 430	3 430	3 430	3 428	3 440	7 880	15 379	20 774
	Other RES		144	160	178	200	220	534	1 084	2 685
Net import, GWh	Total		3 898	-1 304	-6 771	-2 783	-9 125	-10 611	-10 163	182
	BG		3 572	1 344	-332	1 455	-3 500	7 247	6 553	-604
	IT		-3 114	-3 076	-2 988	-2 615	-2 186	-17 655	-17 936	1 928
	MK		1 157	349	-1 725	-1 021	-1 545	50	776	-336
	AL		1 217	470	-1 028	-507	-1 071	354	1 153	175
	TR		1 066	-390	-698	-95	-824	-607	-709	-980
Net import ratio, %			7.6%	-2.4%	-13.0%	-5.5%	-17.4%	-19.9%	-18.9%	0.3%
RES-E share (RES-E production/gross consumption, %)			23.5%	21.9%	21.4%	20.6%	19.2%	31.5%	49.2%	64.6%
Utilisation rates of RES-E technical potential, %	Hydro		na	na	na	na	na	na	na	31%
	Wind		na	na	na	na	na	na	na	28%
	Solar		na	na	na	na	na	na	na	54%
Utilisation rates of conventional power production, %	Coal and lignite		52.0%	55.8%	58.2%	52.2%	52.5%	56.9%	40.7%	3.0%
	Natural gas		26.5%	28.3%	56.3%	63.3%	74.7%	79.9%	80.8%	55.2%
	Nuclear		na	na	na	na	na	na	na	na
Natural gas consumption of power generation, TWh			22.30	27.41	54.67	59.31	76.31	71.15	58.84	32.94
Security of supply	Generation adequacy margin		91%	107%	80%	56%	55%	43%	33%	28%
	System adequacy margin		110%	126%	111%	94%	92%	99%	134%	135%
CO ₂ emission	Emission, Mt CO ₂		31.2	37.1	30.8	23.6	24.9	21.3	15.6	6.9
	CO ₂ emission reduction compared to 1990, %		17.7%	2.2%	18.8%	37.8%	34.3%	43.9%	58.9%	81.8%
Spreads	Clean dark spread, €(2015)/MWh		18.4	15.0	17.9	14.8	13.4	13.9	6.6	-13.6
	Clean spark spread, €(2015)/MWh		0.2	-0.7	1.4	1.5	1.6	0.5	0.2	-7.7
Price impacts	Electricity wholesale price, €(2015)/MWh		36.8	41.1	51.8	60.2	68.4	77.7	90.6	90.5
	Total RES-E support/gross consumption, €(2015)/MWh, five year average		na	22.6	14.3	13.7	3.4	0	0	0
	Revenue from CO ₂ auction/gross consumption, €(2015)/MWh		5.2	10.4	13.3	15.7	19.9	19.9	20.0	11.0
Investment cost, m€/5 year period	Coal and lignite		na	1 724	0	0	0	0	0	0
	Natural gas		na	781	0	367	1 833	1 097	0	0
	Total Fossil		na	2 505	0	367	1 833	1 097	0	0
	Total RES-E		na	27	14	449	1 429	4 994	5 370	4 734
	Total		na	2 532	14	816	3 261	6 091	5 370	4 734
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		16.58	17.89	20.68	22.61	24.94	28.54	31.33	31.41
	CO ₂ price, €(2015)/t		8.60	15.00	22.50	33.50	42.00	50.00	69.00	88.00

TABLE A2 | 'DELAYED' SCENARIO

			2016	2020	2025	2030	2035	2040	2045	2050
Installed capacity, MW	Coal, lignite	Existing	4 736	4 736	2 624	1 714	1 315	685	375	375
		New	0	660	660	660	660	660	660	660
	Natural gas	Existing	5 081	5 081	5 081	4 521	3 243	1 333	334	0
		New	0	845	845	845	1 645	1 645	1 645	1 134
	Nuclear	Existing	0	0	0	0	0	0	0	0
		New	0	0	0	0	0	0	0	0
	HFO/LFO		2 019	1 835	1 370	284	284	0	0	0
	Hydro		3 449	4 329	4 369	4 383	4 397	4 411	4 379	4 574
	Wind		2 298	2 111	2 597	2 400	2 894	4 135	5 892	8 156
	Solar		2 615	2 615	5 970	5 987	6 384	12 247	16 892	20 888
	Other RES		56	72	174	201	332	516	970	1 530
Gross consumption, GWh			51 440	53 594	51 826	50 134	52 233	53 314	53 913	55 392
Net electricity generation, GWh	Total		47 540	54 813	54 344	48 568	52 623	50 022	51 640	56 548
	Coal and lignite		21 572	26 370	16 711	10 240	8 355	6 158	2 199	447
	Natural gas		11 796	14 582	18 686	21 337	25 587	14 623	8 358	2 373
	Nuclear		0	0	0	0	0	0	0	0
	HFO/LFO		2 105	2 105	1 684	0	0	0	0	0
	Hydro		4 459	4 459	4 501	4 501	4 501	4 500	4 496	4 850
	Wind		4 034	3 706	4 560	4 214	5 081	7 260	10 328	14 258
	Solar		3 430	3 430	7 830	7 853	8 374	16 061	22 074	27 048
	Other RES		144	160	372	423	724	1 420	4 186	7 572
	Total		3 900	-1 220	-2 518	1 567	-390	3 292	2 273	-1 156
Net import, GWh	BG		3 584	1 461	2 054	2 803	-53	5 353	-1 025	-2 025
	IT		-3 114	-3 051	-2 664	-891	136	-1 857	3 461	1 381
	MK		1 120	365	-591	-142	260	17	231	27
	AL		1 244	403	-357	381	146	134	604	358
	TR		1 066	-398	-959	-584	-879	-355	-996	-897
	Total		7.6%	-2.3%	-4.9%	3.1%	-0.7%	6.2%	4.2%	-2.1%
Net import ratio, %			7.6%	-2.3%	-4.9%	3.1%	-0.7%	6.2%	4.2%	-2.1%
RES-E share (RES-E production/gross consumption, %)			23.5%	21.9%	33.3%	33.9%	35.8%	54.8%	76.2%	97.0%
Utilisation rates of RES-E technical potential, %	Hydro		na	na	na	na	na	na	na	34%
	Wind		na	na	na	na	na	na	na	53%
	Solar		na	na	na	na	na	na	na	72%
Utilisation rates of conventional power production, %	Coal and lignite		52.0%	55.8%	58.1%	49.2%	48.3%	52.3%	24.2%	4.9%
	Natural gas		26.5%	28.1%	36.0%	45.4%	59.8%	56.1%	48.2%	23.9%
	Nuclear		na	na	na	na	na	na	na	na
Natural gas consumption of power generation, TWh			22.29	27.26	34.97	39.92	46.73	26.68	15.05	4.54
Security of supply	Generation adequacy margin		91%	107%	85%	57%	43%	15%	7%	11%
	System adequacy margin		110%	126%	115%	94%	79%	80%	130%	134%
CO ₂ emission	Emission, Mt CO ₂		31.2	37.0	26.8	18.9	18.1	11.7	5.3	1.4
	CO ₂ emission reduction compared to 1990, %		17.7%	2.3%	29.4%	50.0%	52.1%	69.0%	86.1%	96.4%
Spreads	Clean dark spread, €(2015)/MWh		18.4	15.0	16.2	13.4	12.1	16.7	1.6	-31.5
	Clean spark spread, €(2015)/MWh		0.2	-0.7	-0.3	0.2	0.2	3.3	-4.8	-25.6
Price impacts	Electricity wholesale price, €(2015)/MWh		36.8	41.1	50.1	58.9	67.0	80.5	85.6	72.6
	Total RES-E support/gross consumption, €(2015)/MWh, five year average		na	22.6	17.7	14.4	4.8	4.0	6.0	35.1
	Revenue from CO ₂ auction/gross consumption, €(2015)/MWh		5.2	10.4	11.6	12.7	14.6	11.0	6.7	2.2
	Total		na	2 532	4 458	790	3 379	7 288	6 685	8 522
Investment cost, m€/5 year period	Coal and lignite		na	1 724	0	0	0	0	0	0
	Natural gas		na	781	0	0	732	0	0	0
	Total Fossil		na	2 505	0	0	732	0	0	0
	Total RES-E		na	27	4 458	790	2 646	7 288	6 685	8 522
	Total		na	2 532	4 458	790	3 379	7 288	6 685	8 522
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		16.58	17.89	20.68	22.61	24.94	28.54	31.33	31.41
	CO ₂ price, €(2015)/t		8.60	15.00	22.50	33.50	42.00	50.00	69.00	88.00

TABLE A3 | 'DECARBONISATION' SCENARIO

			2016	2020	2025	2030	2035	2040	2045	2050
Installed capacity, MW	Coal, lignite	Existing	4 736	4 736	2 624	1 714	1 315	685	375	375
		New	0	0	0	0	0	0	0	0
	Natural gas	Existing	5 081	5 081	5 081	4 521	3 243	1 333	334	0
		New	0	845	845	845	1 645	1 645	1 645	1 134
	Nuclear	Existing	0	0	0	0	0	0	0	0
		New	0	0	0	0	0	0	0	0
	HFO/LFO		2 019	1 835	1 370	284	284	0	0	0
	Hydro		3 449	4 329	4 472	4 486	4 500	4 514	4 483	4 451
	Wind		2 298	2 111	2 830	3 176	3 864	5 500	7 718	10 485
Gross consumption, GWh	Solar		2 615	2 615	6 221	10 082	14 403	15 711	16 339	18 540
	Other RES		56	72	247	376	533	979	1 494	1 646
	Total		51 440	53 579	51 807	50 128	52 297	53 311	53 912	55 366
	Coal and lignite		47 540	55 530	58 505	53 337	56 479	54 754	55 612	57 290
	Natural gas		21 572	21 573	11 923	5 621	3 072	1 567	402	20
	Nuclear		11 796	20 096	26 412	23 279	21 795	14 165	8 307	2 319
	HFO/LFO		0	0	0	0	0	0	0	0
	Hydro		2 105	2 105	1 684	0	0	0	0	0
	Wind		4 459	4 459	4 668	4 668	4 651	4 665	4 663	4 654
Net electricity generation, GWh	Wind		4 034	3 706	4 969	5 575	6 756	9 645	13 526	18 337
	Solar		3 430	3 430	8 160	13 225	18 641	20 550	21 338	24 048
	Other RES		144	160	689	969	1 564	4 161	7 376	7 913
	Total		3 900	-1 951	-6 699	-3 209	-4 182	-1 443	-1 700	-1 924
	BG		3 584	927	-400	489	-338	4 353	-1 252	-4 595
	IT		-3 114	-3 055	-2 262	-1 176	-573	-4 560	1 446	4 784
	MK		1 120	-346	-2 095	-1 347	-1 587	-759	-969	-935
	AL		1 244	-234	-1 423	-960	-775	-115	-79	-379
	TR		1 066	757	-519	-216	-908	-362	-847	-798
Net import ratio, %			7.6%	-3.6%	-12.9%	-6.4%	-8.0%	-2.7%	-3.2%	-3.5%
RES-E share (RES-E production/gross consumption, %)			23.5%	21.9%	35.7%	48.7%	60.4%	73.2%	87.0%	99.3%
Utilisation rates of RES-E technical potential, %	Hydro		na	na	na	na	na	na	na	33%
	Wind		na	na	na	na	na	na	na	68%
	Solar		na	na	na	na	na	na	na	64%
Utilisation rates of conventional power production, %	Coal and lignite		52.0%	52.0%	51.9%	37.4%	26.7%	26.1%	12.3%	0.6%
	Natural gas		26.5%	38.7%	50.9%	49.5%	50.9%	54.3%	47.9%	23.3%
	Nuclear		na	na	na	na	na	na	na	na
Natural gas consumption of power generation, TWh			22.29	37.49	49.44	43.56	39.85	25.85	14.98	4.44
Security of supply	Generation adequacy margin		91%	100%	80%	54%	41%	16%	12%	10%
	System adequacy margin		110%	119%	110%	91%	76%	80%	136%	135%
CO ₂ emission	Emission, Mt CO ₂		31.2	34.2	24.8	15.1	11.4	6.9	3.4	0.9
	CO ₂ emission reduction compared to 1990, %		17.7%	9.6%	34.4%	60.3%	70.0%	81.7%	90.9%	97.6%
Spreads	Clean dark spread, €(2015)/MWh		18.4	16.0	17.5	13.9	8.1	16.9	1.9	-30.0
	Clean spark spread, €(2015)/MWh		0.2	0.2	1.1	0.6	-3.7	3.5	-4.6	-24.0
Price impacts	Electricity wholesale price, €(2015)/MWh		36.8	42.0	51.5	59.3	63.0	80.7	85.8	74.2
	Total RES-E support/gross consumption, €(2015)/MWh, five year average		na	22.6	17.4	19.3	11.4	7.7	4.8	4.7
	Revenue from CO ₂ auction/gross consumption, €(2015)/MWh		5.2	9.6	10.8	10.1	9.1	6.5	4.4	1.5
Investment cost, m€/5 year period	Coal and lignite		na	0	0	0	0	0	0	0
	Natural gas		na	780.9	0	0	732.5	0	0	0
	Total Fossil		na	780.9	0	0	732.5	0	0	0
	Total RES-E		na	27	5 915	5 005	7 616	6 484	5 596	7 666
	Total		na	808	5 915	5 005	8 348	6 484	5 596	7 666
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		16.58	17.89	20.68	22.61	24.94	28.54	31.33	31.41
	CO ₂ price, €(2015)/t		8.60	15.00	22.50	33.50	42.00	50.00	69.00	88.00

TABLE A4 | SENSITIVITY ANALYSIS – LOW CARBON PRICE

			2016	2020	2025	2030	2035	2040	2045	2050
Installed capacity, MW	Coal, lignite	Existing	4 736	4 736	2 624	1 714	1 315	685	375	375
		New	0	0	0	0	0	0	0	0
	Natural gas	Existing	5 081	5 081	5 081	4 521	3 243	1 333	334	0
		New	0	845	845	845	1 245	1 245	1 245	734
	Nuclear	Existing	0	0	0	0	0	0	0	0
		New	0	0	0	0	0	0	0	0
	HFO/LFO		2 019	1 835	1 370	284	284	0	0	0
	Hydro		3 449	4 329	4 642	4 656	4 670	4 684	4 652	4 621
	Wind		2 298	2 111	2 830	3 176	3 864	5 482	7 576	10 242
Gross consumption, GWh	Solar		2 615	2 615	6 936	10 941	14 284	15 506	16 355	18 999
	Other RES		56	72	303	439	665	1 232	1 582	1 718
	Total		51 476	53 610	51 889	50 281	52 474	53 477	54 190	55 755
	Coal and lignite		49 786	52 984	55 959	47 378	48 196	51 321	51 426	56 588
	Natural gas		21 573	21 573	11 949	7 320	5 227	2 642	1 119	351
	Nuclear		14 039	17 550	22 504	14 084	10 802	8 617	3 419	1 319
	HFO/LFO		0	0	0	0	0	0	0	0
	Hydro		2 105	2 105	1 684	0	0	0	0	0
	Wind		4 459	4 459	4 943	4 940	4 910	4 911	4 917	4 896
Net electricity generation, GWh	Wind		4 034	3 706	4 969	5 570	6 732	9 547	13 215	17 791
	Solar		3 430	3 430	9 097	14 315	18 307	19 872	21 045	24 145
	Other RES		144	160	813	1 150	2 217	5 732	7 711	8 086
	Total		1 690	626	-4 070	2 903	4 277	2 157	2 764	-833
	BG		3 423	2 921	1 158	4 909	5 510	6 824	2 160	125
	IT		-3 114	-2 845	-1 301	-187	-133	-4 274	1 646	-387
	MK		782	622	-1 797	-817	-177	-107	-609	136
	AL		1 083	900	-1 030	-170	-151	-63	233	429
	TR		-484	-972	-1 101	-832	-772	-223	-665	-1 135
Net import ratio, %			3.3%	1.2%	-7.8%	5.8%	8.2%	4.0%	5.1%	-1.5%
RES-E share (RES-E production/gross consumption, %)			23.4%	21.9%	38.2%	51.7%	61.3%	74.9%	86.5%	98.5%
Utilisation rates of RES-E technical potential, %	Hydro		na	na	na	na	na	na	na	34.5%
	Wind		na	na	na	na	na	na	na	68.3%
	Solar		na	na	na	na	na	na	na	65.3%
Utilisation rates of conventional power production, %	Coal and lignite		52.0%	52.0%	52.0%	48.8%	45.4%	44.0%	34.1%	10.7%
	Natural gas		31.5%	33.8%	43.3%	30.0%	27.5%	38.2%	24.7%	20.5%
	Nuclear		na	na	na	na	na	na	na	na
Natural gas consumption of power generation, TWh			26.3	32.8	42.3	26.5	20.1	16.2	6.5	2.7
Security of supply	Generation adequacy margin		91%	100%	83%	57%	40%	16%	10%	6%
	System adequacy margin		110%	119%	114%	94%	75%	80%	133%	131%
CO ₂ emission	Emission, Mt CO ₂		32.0	33.3	23.4	13.7	9.9	6.2	2.5	0.9
	CO ₂ emission reduction compared to 1990, %		15.6%	12.1%	38.1%	63.7%	73.9%	83.6%	93.3%	97.5%
Spreads	Clean dark spread, €(2015)/MWh		16.0	14.0	12.0	3.4	-3.6	6.4	-15.6	-54.3
	Clean spark spread, €(2015)/MWh		-2.2	-1.7	-4.4	-9.8	-15.4	-7.0	-22.0	-48.3
Price impacts	Electricity wholesale price, €(2015)/MWh		34.4	40.1	46.0	48.9	51.3	70.1	68.4	49.9
	Total RES-E support/gross consumption, €(2015)/MWh, five year average		na	22.9	26.0	28.3	23.6	21.6	24.1	47.6
	Revenue from CO ₂ auction/gross consumption, €(2015)/MWh		5.3	9.3	10.2	9.2	7.9	5.8	3.2	1.5
Investment cost, m€/5 year period	Coal and lignite		na	0	0	0	0	0	0	0
	Natural gas		na	781	0	0	366	0	0	0
	Total Fossil		na	781	0	0	366	0	0	0
	Total RES-E		na	27	6 484	4 990	5 590	4 776	4 525	8 349
	Total		na	808	6 484	4 990	5 957	4 776	4 525	8 349
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		16.58	17.89	20.68	22.61	24.94	28.54	31.33	31.41
	CO ₂ price, €(2015)/t		4.30	7.50	11.25	16.75	21.00	25.00	34.50	44.00

TABLE A5 | SENSITIVITY ANALYSIS – LOW DEMAND

			2016	2020	2025	2030	2035	2040	2045	2050
Installed capacity, MW	Coal, lignite	Existing	4 736	4 736	2 624	1 714	1 315	685	375	375
		New	0	0	0	0	0	0	0	0
	Natural gas	Existing	5 081	5 081	5 081	4 521	3 243	1 333	334	0
		New	0	845	845	845	1 645	1 645	1 645	1 134
	Nuclear	Existing	0	0	0	0	0	0	0	0
		New	0	0	0	0	0	0	0	0
	HFO/LFO		2 019	1 835	1 370	284	284	0	0	0
	Hydro		3 449	4 329	4 472	4 486	4 500	4 514	4 483	4 451
	Wind		2 298	2 111	2 597	2 802	3 330	4 765	6 759	9 258
Gross consumption, GWh	Solar		2 615	2 615	6 136	6 868	7 990	13 176	16 862	18 711
	Other RES		56	72	228	315	391	556	1 109	1 433
	Total		51 440	53 058	50 673	48 422	49 800	50 160	50 274	50 908
	Coal and lignite		47 542	54 430	57 530	52 552	53 849	50 692	51 670	54 843
	Natural gas		21 572	21 573	11 934	5 980	4 143	2 037	412	18
	Nuclear		11 797	18 996	25 984	27 156	27 639	16 378	7 420	2 359
	HFO/LFO		0	0	0	0	0	0	0	0
	Hydro		2 105	2 105	1 684	0	14	0	0	0
	Wind		4 459	4 459	4 668	4 668	4 668	4 665	4 650	4 651
Net electricity generation, GWh	Solar		4 034	3 706	4 560	4 920	5 846	8 356	11 809	16 178
	Other RES		3 430	3 430	8 049	9 009	10 481	17 235	21 813	24 210
	Total		144	160	652	818	1 058	2 020	5 566	7 427
	BG		3 899	-1 372	-6 857	-4 130	-4 049	-532	-1 395	-3 936
	IT		3 547	1 004	-304	-142	-1 664	2 081	-2 848	-5 284
	MK		-3 114	-3 021	-2 596	-1 474	315	-655	3 364	4 136
	AL		1 142	-132	-2 106	-1 652	-1 652	-1 511	-1 252	-1 468
	TR		1 257	128	-1 479	-1 134	-644	-610	-106	-724
	TR		1 066	648	-372	272	-405	163	-553	-596
Net import ratio, %			7.6%	-2.6%	-13.5%	-8.5%	-8.1%	-1.1%	-2.8%	-7.7%
RES-E share (RES-E production/gross consumption, %)			23.5%	22.2%	35.4%	40.1%	44.3%	64.3%	87.2%	103.1%
Utilisation rates of RES-E technical potential, %	Hydro		na	na	na	na	na	na	na	32.6%
	Wind		na	na	na	na	na	na	na	60.3%
	Solar		na	na	na	na	na	na	na	64.3%
Utilisation rates of conventional power production, %	Coal and lignite		52.0%	52.0%	51.9%	39.8%	36.0%	33.9%	12.5%	0.6%
	Natural gas		26.5%	36.6%	50.1%	57.8%	64.5%	62.8%	42.8%	23.7%
	Nuclear		na	na	na	na	na	na	na	na
Natural gas consumption of power generation, TWh			22.3	35.4	48.6	50.8	50.6	30.0	13.5	4.5
Security of supply	Generation adequacy margin		91%	101%	83%	57%	45%	16%	12%	12%
	System adequacy margin		110%	121%	114%	96%	83%	84%	142%	144%
CO ₂ emission	Emission, Mt CO ₂		31.2	33.8	24.7	16.9	14.8	8.3	3.2	0.9
	CO ₂ emission reduction compared to 1990, %		17.7%	10.7%	34.8%	55.3%	61.0%	78.1%	91.7%	97.6%
Spreads	Clean dark spread, €(2015)/MWh		18.4	15.8	17.4	14.5	15.1	23.3	-3.1	-29.4
	Clean spark spread, €(2015)/MWh		0.2	0	0.9	1.3	3.3	9.9	-9.6	-23.5
Price impacts	Electricity wholesale price, €(2015)/MWh		36.8	41.9	51.3	60.0	70.1	87.1	80.8	74.7
	Total RES-E support/gross consumption, €(2015)/MWh, five year average		na	22.6	19.5	16.1	6.4	0.6	0	0
	Revenue from CO ₂ auction/gross consumption, €(2015)/MWh		5.2	9.6	11.0	11.7	12.4	8.3	4.3	1.6
	Total		na	808	4 982	1 907	4 046	7 195	6 333	7 289
Investment cost, m€/5 year period	Coal and lignite		na	0	0	0	0	0	0	0
	Natural gas		na	780.9	0	0	732.5	0	0	0
	Total Fossil		na	781	0	0	732	0	0	0
	Total RES-E		na	27	4 982	1 907	3 314	7 195	6 333	7 289
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		16.58	17.89	20.68	22.61	24.94	28.54	31.33	31.41
	CO ₂ price, €(2015)/t		8.60	15.00	22.50	33.50	42.00	50.00	69.00	88.00

TABLE A6 | SENSITIVITY ANALYSIS – HIGH DEMAND

			2016	2020	2025	2030	2035	2040	2045	2050
Installed capacity, MW	Coal, lignite	Existing	4 736	4 736	2 624	1 714	1 315	685	375	375
		New	0	0	0	0	0	0	0	0
	Natural gas	Existing	5 081	5 081	5 081	4 521	3 243	1 333	334	0
		New	0	845	845	845	1 645	1 645	1 645	1 134
	Nuclear	Existing	0	0	0	0	0	0	0	0
		New	0	0	0	0	0	0	0	0
	HFO/LFO		2 019	1 835	1 370	284	284	0	0	0
	Hydro		3 449	4 329	4 642	4 656	4 670	4 684	4 652	4 621
	Wind		2 298	2 111	2 830	3 176	3 864	5 482	7 594	10 273
	Solar		2 615	2 615	6 936	12 020	14 807	15 568	16 126	18 910
Other RES			56	72	304	434	635	1 149	1 576	1 728
Gross consumption, GWh			51 440	54 103	52 963	51 907	54 806	56 612	57 976	60 255
Net electricity generation, GWh	Total		47 542	56 627	60 246	55 294	56 879	54 559	54 423	57 860
	Coal and lignite		21 572	21 573	11 917	5 404	3 018	1 499	403	48
	Natural gas		11 797	21 193	26 822	22 582	21 208	13 387	7 371	2 497
	Nuclear		0	0	0	0	0	0	0	0
	HFO/LFO		2 105	2 105	1 684	0	0	0	0	0
	Hydro		4 459	4 459	4 943	4 938	4 919	4 924	4 922	4 917
	Wind		4 034	3 706	4 969	5 566	6 744	9 576	13 263	17 923
	Solar		3 430	3 430	9 097	15 702	19 078	20 140	20 824	24 338
	Other RES		144	160	814	1 103	1 912	5 033	7 640	8 137
Net import, GWh	Total		3 899	-2 524	-7 283	-3 388	-2 073	2 053	3 553	2 395
	BG		3 572	721	-650	343	1 145	5 894	1 399	-1 619
	IT		-3 114	-3 065	-2 342	-993	-272	-3 132	3 510	5 620
	MK		1 166	-638	-2 179	-1 744	-1 182	-314	-339	-545
	AL		1 208	-394	-1 565	-763	-667	138	116	-10
	TR		1 066	853	-547	-230	-1 097	-533	-1 133	-1 051
	Net import ratio, %		7.6%	-4.7%	-13.8%	-6.5%	-3.8%	3.6%	6.1%	4.0%
RES-E share (RES-E production/gross consumption, %)			23.5%	21.7%	37.4%	52.6%	59.6%	70.1%	80.5%	91.8%
Utilisation rates of RES-E technical potential, %	Hydro		na	na	na	na	na	na	na	34.5%
	Wind		na	na	na	na	na	na	na	68.3%
	Solar		na	na	na	na	na	na	na	65.0%
Utilisation rates of conventional power production, %	Coal and lignite		52.0%	52.0%	51.8%	36.0%	26.2%	25.0%	12.3%	1.5%
	Natural gas		26.5%	40.8%	51.7%	48.0%	49.5%	51.3%	42.5%	25.1%
	Nuclear		na	na	na	na	na	na	na	na
Natural gas consumption of power generation, TWh			22.3	39.5	50.2	42.3	38.8	24.5	13.4	4.7
Security of supply	Generation adequacy margin		91%	98%	80%	52%	39%	14%	9%	4%
	System adequacy margin		110%	117%	109%	88%	72%	75%	125%	121%
CO ₂ emission	Emission, Mt CO ₂		31.2	34.7	25.0	14.6	11.1	6.6	3.1	1.0
	CO ₂ emission reduction compared to 1990, %		17.7%	8.5%	34.0%	61.6%	70.7%	82.6%	91.8%	97.3%
Spreads	Clean dark spread, €(2015)/MWh		27.5	32.1	41.6	48.0	52.2	67.1	71.2	61.3
	Clean spark spread, €(2015)/MWh		3.7	6.5	10.3	12.7	12.7	20.7	19.2	9.1
Price impacts	Electricity wholesale price, €(2015)/MWh		36.8	42.2	51.6	57.9	62.5	77.7	81.9	71.9
	Total RES-E support/gross consumption, €(2015)/MWh, five year average		na	22.6	25.3	24.9	18.0	12.6	11.4	27.6
	Revenue from CO ₂ auction/gross consumption, €(2015)/MWh		5.2	9.6	10.6	9.4	8.5	5.8	3.7	1.5
Investment cost, m€/5 year period	Coal and lignite		na	780.9	0	0	366.3	0	0	0
	Natural gas		na	0	0	0	0	0	0	0
	Total Fossil		na	781	0	0	366	0	0	0
	Total RES-E		na	27	6 485	6 013	5 203	4 304	4 400	8 457
	Total		na	808	6 485	6 013	5 569	4 304	4 400	8 457
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		16.58	17.89	20.68	22.61	24.94	28.54	31.33	31.41
	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	4 736	4 736	2 624	1 714	1 315	685	375	375
		New	0	0	0	0	0	0	0	0
	Natural gas	Existing	5 081	5 081	5 081	4 521	3 243	1 333	334	0
		New	0	845	845	845	1 645	1 645	1 645	1 134
	Nuclear	Existing	0	0	0	0	0	0	0	0
		New	0	0	0	0	0	0	0	0
	HFO/LFO		2 019	1 835	1 370	284	284	0	0	0
	Hydro		3 449	4 329	4 486	4 500	4 514	4 528	4 542	4 600
	Wind		2 298	2 111	2 723	3 212	3 903	5 387	7 164	9 084
	Solar		2 615	2 615	7 466	12 518	16 210	18 851	20 889	23 291
Other RES			56	72	283	393	536	721	926	1 409
Gross consumption, GWh			51 440	53 578	51 808	50 145	52 353	53 348	53 940	55 371
Net electricity generation, GWh	Total		47 549	55 791	59 428	55 707	57 695	56 324	56 357	58 594
	Coal and lignite		21 572	21 573	11 923	5 486	3 010	1 602	435	20
	Natural gas		11 804	20 356	25 799	22 535	21 319	14 280	8 431	2 431
	Nuclear		0	0	0	0	0	0	0	0
	HFO/LFO		2 105	2 105	1 684	0	0	0	0	0
	Hydro		4 459	4 459	4 691	4 688	4 647	4 670	4 755	4 890
	Wind		4 034	3 706	4 780	5 633	6 783	9 409	12 544	15 870
	Solar		3 430	3 430	9 794	16 380	20 588	24 329	27 209	30 101
	Other RES		144	160	757	985	1 348	2 034	2 982	5 280
	Total		3 892	-2 212	-7 619	-5 563	-5 342	-2 976	-2 416	-3 223
Net import, GWh	BG		3 524	625	-475	-672	-1 038	3 736	-942	-2 201
	IT		-3 114	-3 048	-2 568	-1 633	-1 311	-5 118	-239	1 070
	MK		1 109	-361	-2 384	-1 869	-1 389	-1 051	-628	-1 336
	AL		1 307	-213	-1 672	-1 108	-656	-184	228	-11
	TR		1 066	785	-519	-281	-948	-359	-834	-745
	Total		7.6%	-4.1%	-14.7%	-11.1%	-10.2%	-5.6%	-4.5%	-5.8%
Net import ratio, %			7.6%	-4.1%	-14.7%	-11.1%	-10.2%	-5.6%	-4.5%	-5.8%
RES-E share (RES-E production/gross consumption, %)			23.5%	21.9%	38.6%	55.2%	63.7%	75.8%	88.0%	101.4%
Utilisation rates of RES-E technical potential, %	Hydro		na	na	na	na	na	na	na	34.3%
	Wind		na	na	na	na	na	na	na	59.8%
	Solar		na	na	na	na	na	na	na	79.8%
Utilisation rates of conventional power production, %	Coal and lignite		52.0%	52.0%	51.9%	36.5%	26.1%	26.7%	13.3%	0.6%
	Natural gas		26.5%	39.2%	49.7%	47.9%	49.8%	54.7%	48.6%	24.5%
	Nuclear		na	na	na	na	na	na	na	na
Natural gas consumption of power generation, TWh			22.3	38.0	48.3	42.2	39.0	26.1	15.2	4.6
Security of supply	Generation adequacy margin		91%	100%	81%	54%	41%	10%	2%	2%
	System adequacy margin		110%	119%	111%	91%	76%	76%	125%	126%
CO ₂ emission	Emission, Mt CO ₂		31.2	34.3	24.6	14.6	11.1	7.0	3.5	1.0
	CO ₂ emission reduction compared to 1990, %		17.7%	9.4%	35.0%	61.4%	70.6%	81.5%	90.7%	97.5%
Spreads	Clean dark spread, €(2015)/MWh		27.5	31.9	41.3	48.4	49.4	68.0	73.7	63.6
	Clean spark spread, €(2015)/MWh		3.7	6.3	10.0	13.0	9.8	21.5	21.6	11.4
Price impacts	Electricity wholesale price, €(2015)/MWh		36.8	42.1	51.4	58.3	59.7	78.6	84.3	74.2
	Total RES-E support/gross consumption, €(2015)/MWh, five year average		na	22.5	25.9	23.0	16.4	12.8	15.7	122.0
	Revenue from CO ₂ auction/gross consumption, €(2015)/MWh		5.2	9.6	10.7	9.8	8.9	6.6	4.5	1.5
Investment cost, m€/5 year period	Coal and lignite		na	780.9	0	0	732.5	0	0	0
	Natural gas		na	0	0	0	0	0	0	0
	Total Fossil		na	781	0	0	732	0	0	0
	Total RES-E		na	27	6 734	6 025	5 838	5 099	4 854	8 898
	Total		na	808	6 734	6 025	6 570	5 099	4 854	8 898
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		16.58	17.89	20.68	22.61	24.94	28.54	31.33	31.41
	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	230	249	1 500
Solid biomass	110	159	1 363
Biowaste	194	239	215
Geothermal ele.	111	234	262
Hydro large-scale	–	351	1 239
Hydro small-scale	–	40	75
Central PV	3 698	6 805	8 143
Decentralised PV	6 856	10 203	9 831
CSP	–	52	–
Wind onshore	5 320	11 183	14 744
Wind offshore	498	903	935
RES-E total	17 016	30 417	38 308

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	7 005	4 391	4 028	1 012	–	–	–	16 435
Central PV	2 661	1 571	1 457	340	–	–	–	6 028
Decentralised PV	3 644	2 372	2 216	529	–	–	–	8 761
Wind onshore	559	347	267	94	–	–	–	1 268
Delayed	7 005	5 414	4 218	1 428	1 223	1 839	10 810	31 937
Central PV	2 661	1 835	1 501	411	249	441	2 555	9 652
Decentralised PV	3 644	2 703	2 273	628	333	512	2 515	12 609
Wind onshore	559	705	348	314	565	742	4 520	7 752
Decarbon	7 001	5 326	5 671	3 357	2 347	1 450	1 464	26 617
Central PV	2 660	1 837	2 057	1 419	1 389	1 093	955	11 411
Decentralised PV	3 644	2 809	2 918	1 577	878	285	508	12 618
Wind onshore	557	579	608	312	44	–	–	2 100

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

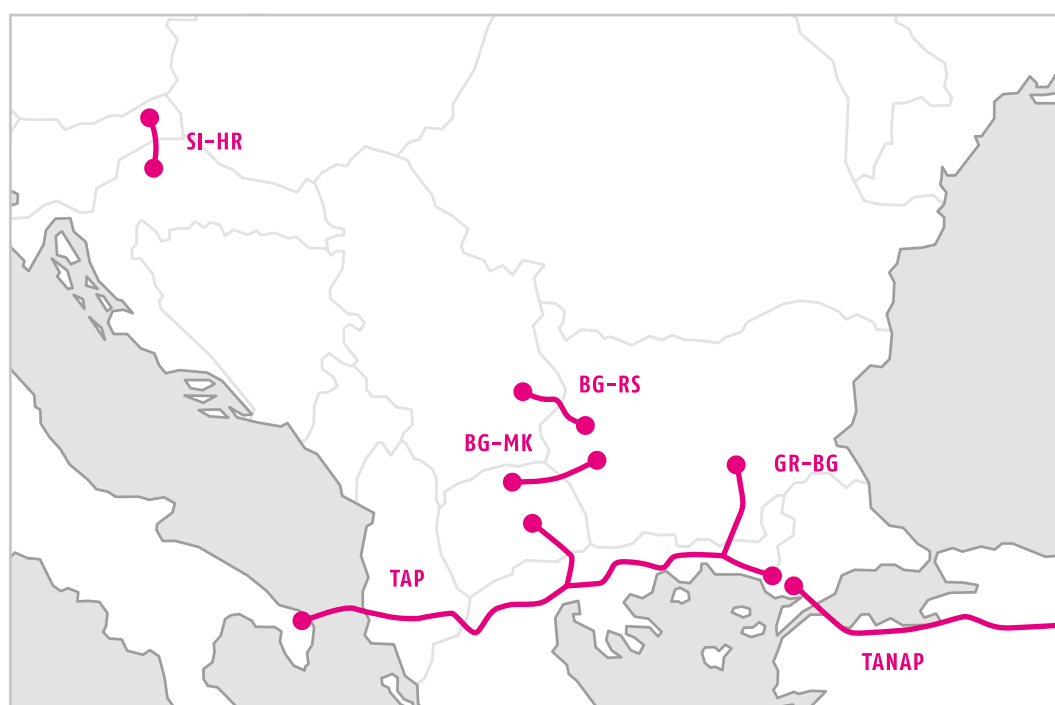
Infrastructure (table for the whole region)

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
Liptol II.	30.0	1985	2014	lignite	thermal	no	yes	yes	yes
Liptol II.	0	1985	2040	coal	thermal	no	yes	yes	yes
Agios Georgios I	160.0	1968	2014	natural gas	thermal	no	yes	yes	yes
Aliveri III	150.0	1969	2024	HFO	thermal	no	yes	yes	yes
Aliveri IV	150.0	1969	2024	HFO	thermal	no	yes	yes	yes
Agios Georgios II	200.0	1971	2014	natural gas	thermal	no	yes	yes	yes
Lavrio Steam I	130.0	1972	2027	HFO	thermal	no	yes	yes	yes
Lavrio Steam II	300.0	1973	2028	HFO	thermal	no	yes	yes	yes
Ptolemaida III-IV	399.0	1973	2031	lignite	thermal	no	yes	yes	yes
Kardia I	300.0	1975	2023	lignite	thermal	no	yes	yes	yes
Kardia II	300.0	1975	2023	lignite	thermal	no	yes	yes	yes
Megalopolis III	300.0	1975	2025	lignite	thermal	no	yes	yes	yes
Kardia III	306.0	1980	2023	lignite	thermal	no	yes	yes	yes
Kardia IV	306.0	1981	2023	lignite	thermal	no	yes	yes	yes
Agios Dimitrios I	300.0	1984	2039	lignite	thermal	no	yes	yes	yes
Agios Dimitrios II	300.0	1984	2030	lignite	thermal	no	yes	yes	yes
Agios Dimitrios III	310.0	1985	2030	lignite	thermal	no	yes	yes	yes
Agios Dimitrios IV	310.0	1986	2041	lignite	thermal	no	yes	yes	yes
Amyntaio I	300.0	1987	2023	lignite	thermal	no	yes	yes	yes
Amyntaio II	300.0	1988	2023	lignite	thermal	no	yes	yes	yes
Megalopolis IV	300.0	1991	2026	lignite	thermal	no	yes	yes	yes
Lavrio IV	560.0	1996	2026	natural gas	CCGT	no	yes	yes	yes
Agios Dimitrios V	375.0	1997	2052	lignite	thermal	no	yes	yes	yes
Lavrio III	569.0	1999	2014	natural gas	CCGT	no	yes	yes	yes
Komotini	484.6	2002	2032	natural gas	CCGT	no	yes	yes	yes
Heron 1, Thiva	148.5	2004	2044	natural gas	OCGT	no	yes	yes	yes
Lavrio V	385.2	2004	2034	natural gas	CCGT	no	yes	yes	yes
Thessaloniki	408.4	2005	2035	natural gas	CCGT	no	yes	yes	yes
Melitis	330.0	2008	2038	lignite	CCGT	no	yes	yes	yes
Aliminium	334.0	2008	2063	natural gas	thermal	no	yes	yes	yes
Agios Nikolaos, Beotia 3	444.5	2009	2039	natural gas	CCGT	no	yes	yes	yes
Korinthos Power	436.6	2010	2040	natural gas	CCGT	no	yes	yes	yes
Heron II	432.0	2010	2040	natural gas	CCGT	no	yes	yes	yes
Aliveri V	429.0	2013	2043	natural gas	CCGT	no	yes	yes	yes
Thisvi	421.6	2011	2041	natural gas	CCGT	no	yes	yes	yes
Megalopolis V.	845.0	2016	2046	natural gas	CCGT	no	yes	yes	yes
Piso Kampos Rhodes	0	2017	2047	LFO	CCGT	no	yes	yes	yes
Ptolemais V	660.0	2018		lignite	thermal	no	yes	yes	no
Crete	164.1		2025	HFO	thermal	no	yes	yes	yes
Crete	164.1		2026	HFO	thermal	no	yes	yes	yes
Crete	164.1		2027	HFO	thermal	no	yes	yes	yes
Crete	164.1		2028	HFO	thermal	no	yes	yes	yes
Crete	164.1		2029	HFO	thermal	no	yes	yes	yes
Rodos	347.0			natural gas	thermal	no	yes	yes	yes
Other islands	284.0			LFO	thermal	no	yes	yes	yes
Other islands	184.0		2018	LFO	thermal	no	yes	yes	yes
Other	250.0			natural gas	thermal	no	yes	yes	yes

