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Transforming the EU power sector: avoiding a carbon lock-in

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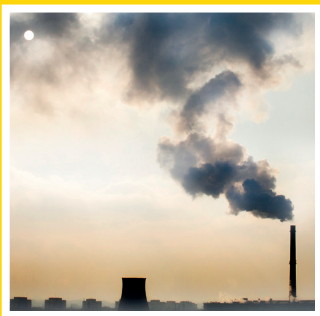

European Environment Agency

Transforming the EU power sector: avoiding a carbon lock-in

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Glossary

AVG	Illustrative sectoral profile obtained from the bottom-up assessment, assuming medium-term capacity lifetimes
BFG	Blast furnace gas
CCS	Carbon capture and storage
CEE	Central-eastern Europe
CI	Carbon intensity: the average rate of emission of a given pollutant from a given source relative to the intensity of a specific activity; for example, grams of carbon dioxide released per megajoule of energy produced, or the ratio of greenhouse gas emissions produced to gross domestic product.
CON	Units under construction
CWE	Central-western Europe
DAC	Units that have been deactivated or mothballed
DEL	Units that are delayed after the start of construction
DG CLIMA	European Commission's Directorate-General for Climate Action
DG ENER	European Commission's Directorate-General for Energy
DG ENV	European Commission's Directorate-General for Environment
DST	Diversified supply technologies. One of the three scenarios from the Energy Roadmap 2050
EEA	European Environment Agency
Eionet	The European Environment Information and Observation Network (Eionet) is a network of environmental bodies and institutions in the EEA member countries
ELV	Emissions limit values set by the Industrial Emissions Directive (IED)
Energy Roadmap 2050	The European Commission's Energy Roadmap, published in 2011, sets out routes to a more sustainable, competitive and secure energy system in 2050. The current study uses three of its scenarios (high energy efficiency, high renewable energy and diversified supply) as the top-down scenarios for comparison with the bottom-up assessment
Energy transition	Long-term structural change towards a more sustainable energy system
E-PRTR/EPRTR	European Pollutant Release and Transfer Register
EU	European Union
EU-28	The 28 Member States of the European Union
EU-27	The 27 Member States of the European Union prior to the accession of Croatia in 2013
ETS	The EU's Emissions Trading System. The EU ETS is one of the main measures introduced by the EU to achieve cost-effective reductions in greenhouse gas (GHG) emissions and reach its targets under the Kyoto Protocol and other commitments. ETS data are recorded in the European Union Transaction Log (EUTL). This study used ETS data on carbon dioxide emissions from power plant units
EUTL	The European Union Transaction Log is an online registry that covers all 31 countries participating in the EU ETS and that is operated by the European Commission. The EUTL holds accounts for stationary installations (transferred from the national registries used before 2012) and for aircraft operators (included in the EU ETS since January 2012)
EXT	Illustrative sectoral profile obtained from the bottom-up assessment using currently expected, longer (extended), capacity lifetimes
GHG	Greenhouse gas

GWe/MWe/TWe	Gigawatt electric/megawatt electric/terawatt electric are the units used to measure the rated electricity capacity of units
GWth	Gigawatt thermal is the unit used to measure the thermal capacity of the input fuel used by units
EE	High energy efficiency. One of the three scenarios from the Energy Roadmap 2050
RES	High renewable energy sources. One of the three scenarios from the Energy Roadmap 2050
IED	Industrial Emissions Directive (2010/75/EU)
Installed capacity	Capacity that is operational, deactivated, mothballed or delayed
IPCC	Intergovernmental Panel on Climate Change. This study used IPCC emissions factors to estimate energy output from carbon dioxide emissions.
LCP	Large combustion plants with a rated thermal input equal to 50 MW or more, irrespective of the type of fuel used (solid, liquid or gaseous) and falling under the scope of the Large Combustion Plant Directive (2001/80/EC)
(LCP) Plant	The level at which emissions are reported under the LCP Directive. A power plant can consist of several units
Lifetime	Lifetime designates the period from the commissioning of a certain asset (unit) until the end of the life of that asset. Technical lifetime is defined as the total period of time during which a unit can technically perform before it must be replaced or shut down. Expected lifetime is the period of time during which a unit is expected to perform before it must be replaced or shut down, based on its technical lifetime and anticipated actual operational lifetime
LNG	Liquefied natural gas
Lock-in	The term lock-in describes a large (fossil fuel-based) technological overcapacity in the power sector, compared with its optimal configuration. It conveys a certain risk of path dependency and inertia in large fossil fuel-based energy systems that inhibit attempts to introduce alternative energy technologies and energy efficiency measures designed to reduce GHG emissions. Specifically, in this report, lock-in indicates the amount of fossil fuel capacity that exceeds the fossil fuel-based capacity in the selected Energy Roadmap 2050 scenarios that are consistent with the EU's 2050 climate objectives
MSR	The market stability reserve (MSR) is a mechanism introduced under the broader EU ETS that aims to increase the carbon market's resilience to sudden shocks by regulating the supply of emissions permits in order to prevent extremes
NEB	Northern Europe and the Baltic States (in this report the Baltic States are referred to as the Baltics)
NO_x	NO_x is a generic term for the mono-nitrogen oxides NO (nitric oxide) and NO_2 (nitrogen dioxide). They are produced as a result of the reaction of nitrogen and oxygen gases in the air during combustion, especially at high temperatures
OPR	Units that are in commercial operation
PLN	Units that are planned
Power sector	The industrial sector responsible for the generation of electric power for consumption by the general public and industry
PPT	Power Plants Tracker (database) — Enerdata
PRIMES	The PRIMES model is an agent-based and price-driven model of the energy system used to obtain the projections for the Energy Roadmap 2050
REV	Illustrative sectoral profile obtained from the bottom-up assessment using extended capacity lifetimes (EXT profile) and taking into account the need for potential upgrading to comply with the IED (it includes the results of the EIONET consultation)
SO_x	Sulphur oxides refer to several sulphur- and oxygen-containing compounds
SSEE	South and south-eastern Europe
Unit	One boiler or turbine
UR	Uranium
WEPP	World Electric Power Plants Database, 2014 — Platts
WSTH	Waste heat

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Executive summary

Europe and the global community are committed to a low-carbon future, a goal to be reached by mid-century. In 2009, the European Council set an objective to reduce EU-wide emissions of greenhouse gases (GHGs) to 80–95 % of the 1990 levels by 2050 (European Council, 2009).

The electricity generating sector is at the heart of Europe's decarbonisation strategy and it is also the focus of this report. To date, power generation remains the largest GHG-emitting sector in Europe, being responsible for roughly one third of all energy-related GHG emissions and more than half of the verified emissions under the EU Emissions Trading Scheme (ETS) (EEA, 2015a; IEA, 2015).

According to the European Commission's Energy Roadmap 2050, by mid-century, the currently available climate mitigation options can deliver a cost-effective decarbonisation of the power sector of 90–98 % compared with 2005 (EC, 2011c). To reach this goal, however, a fundamental change in the composition of Europe's electricity sector will be needed. With fossil fuels still contributing to roughly half of the electricity generated in Europe, moving away from a carbon-intensive power supply over the next few decades will require a commitment to increase investment in clean technology, restructure the fossil fuel energy infrastructure and ensure a secure and affordable power supply.

In this context, this report fills an important information gap by looking at:

- the theoretical evolution of fossil fuel capacity by 2030 in the absence of strong drivers to counter present trends;
- how this hypothetical evolution would fit in with the need to create a qualitatively different EU power sector by 2030 and beyond, in line with EU climate goals.

The concept of 'lock-in' has been extensively used to study the effects of path dependencies and reinforcing effects in the context of transition studies. With regard to the energy system, lock-ins are usually understood as mechanisms inhibiting the diffusion and adoption of carbon-saving technologies (Klitkou, 2015; Frantzeskaki and Loorbach, 2010; Unruh, 2000). Throughout this report, the term 'lock-in' is used to refer to situations where the amount of fossil fuel capacity could exceed the levels that correspond to the EU's long-term decarbonisation objectives according to selected Energy Roadmap 2050 scenarios.

By examining in detail the fuel type, status and age of the existing and planned fossil fuel capacity and the potential lock-ins in the illustrative profiles, this report contributes to a better understanding of the sector and provides useful information for investors and policymakers.

The report also looks at the unintended consequences of the Industrial Emissions Directive (IED) ([1]) on capacity lifetime. By doing so, it contributes to the evaluation of climate and environmental policies and their interactions and, in particular, to broadening our understanding of the coherence between climate and industrial emissions policies.

The report illustrates that, under certain assumptions (in particular regarding the longevity of installed capacity), the EU power sector could evolve towards excessive fossil fuel capacity by 2030, compared with the optimal capacity levels in the Energy Roadmap 2050. The prolonged operation of inflexible, carbon-intensive power plants, along with the planned construction of new fossil fuel capacity, could translate into higher costs for decarbonising Europe's power sector by locking it in to a dependence on a high-carbon capacity, while simultaneously exposing owners and shareholders to the financial risk of capacity closures (potentially stranded assets). Within this context, one question is whether national initiatives that aim to increase the adequacy of domestic generation — currently under discussion in many Member States — could increase fossil fuel (and in particular solid fuel) overcapacity and delay the decommissioning of fossil fuel capacity across Europe (see Box ES.1).

([1]) EU, 2010, Directive 2010/75/EU of the European Parliament and of the Council of 24 November 2010 on industrial emissions (integrated pollution prevention and control) (OJ L 334, 17.12.2010, pp. 17–119.

Box ES.1 Main findings of this report:

- Much of the EU's coal-based power capacity is near the end of its lifetime.
- One quarter of the new fossil fuel capacity in Europe could potentially come from coal.
- At present, operators tend to extend the lifetime of their fossil fuel capacity. If sustained, this would clash with the EU's decarbonisation efforts.
- Modernising power plants to comply with the EU legislation on air pollutants would marginally affect the overall fossil fuel capacity, but would slightly increase the excess solid fuel-fired capacity.
- Central and eastern Europe and south and south-eastern Europe are at a lower risk of solid fuel-fired capacity lock-in.

Drawing on this, the following policy considerations are made:

√ A pan-European approach can provide least-cost opportunities for decarbonising the power sector.

√ Regular sharing of information regarding the evolution of fossil fuel capacity over the short- and medium-term can improve the consistency of decarbonisation efforts.

√ Increased alignment of energy, climate and environmental policies can speed up the transition to a secure and sustainable EU power sector.

Approach

The assessment framework is based on the World Electric Power Plants (WEPP) database (Platts, 2014) and other data sources linked to it, in particular the Large Combustion Plants (LCP) and the European Pollutant Release and Transfer Register (LCP-EPRTR) datasets managed by the EEA and the European Commission ([2]), the European Union Transaction Log (EUTL) dataset under the ETS, and the Power Plant Tracker (PPT) database (Enerdata, 2015). The analysis consists of a bottom-up investigation of the current structure of the EU power sector capacity above 200 MWe output — fossil fuel capacity by fuel type, age, GHG intensity and expected lifetime — its potential evolution up to 2030 under current circumstances and how that compares with the EU's optimal decarbonisation scenarios for the power sector, as described in the Energy Roadmap 2050.

The hypothetical evolution of fossil fuel capacity up to 2030 is calculated by extending the life of each power unit into the future, based on its year of commissioning and the generic lifetime assumptions shown in Table ES.1. The latter were derived from the literature and an assessment of the average age of retired units and of the currently expected, longer (extended), lifetime of units in the Platts and Enerdata databases. They also include an assessment (based on country consultations) of the potential need for upgrading across the sector to comply with stricter air pollution limits under the IED. This is important because

Table ES.1 Lifetime assumptions implemented in the bottom-up profiles

Lifetime assumptions / Capacity by fuel type	**Average** (used in AVG profile)	**Extended** (used in EXT and REV ([a]) profiles)
Coal	40 years	50 years
Gas	35 years	45 years
Oil	40 years	50 years

Note: ([a]) In the REV profile, a 20-year lifetime starting with 2023 was implemented for that capacity for which a technical upgrade to comply with the IED was assumed to take place.

([2]) The LCP-EPRTR database contains data reported by EU Member States to the Commission under the European Pollutant Release and Transfer Register (E-PRTR) Regulation and the Large Combustion Plants (LCP) Directive.

technological upgrades tend to extend the lifetime of capacity. Information on the planned expansion of capacity is taken from the Platts database. These conditions led to three illustrative capacity profiles: AVG, the bottom up profile considering historic average lifetimes. EXT, bottom-up profile considering extended lifetimes. REV, bottom-up profile considering potential upgrades/closures to comply with the requirements to reduce air pollutant emissions (including country consultation results).

In this way calculated, the illustrative sector profiles are compared with optimal power sector decarbonisation scenarios in the Energy Roadmap 2050 impact assessment (EC, 2011c). An excess fossil fuel capacity in the illustrative profiles indicates a risk of lock-in or of stranded assets.

The assessment results are calculated for the EU level. The results are also grouped according to four generic country clusters, shown in Box ES.2: central-western Europe, central-eastern Europe, northern Europe and the Baltics, and south and south-eastern Europe.

Care is needed when interpreting the results. The illustrative sector profiles should not be confused with model-based forecasting. They are constructed to reflect credible lifetimes under prevailing market conditions. However, the report does not look at the potential interactions between the illustrative profiles and the implications of the ETS cap between 2020 and 2030 on installed power generation capacity. Similarly, it does not attempt to represent dynamically the evolution of other factors that influence the lifetime of individual fossil fuel capacity in practice, such as international fossil fuel prices, macro-economic conditions and electricity market conditions (including national capacity mechanisms, where they exist). Most information available for new projects is for the five years after the release date (Platts, 2014), with data for the near-term being more reliable than data for capacity expected to come online in later years (see Box 1.5).

Photo: © Tamas Parkanyi, ImaginAIR/EEA

Box ES.2 Regional aggregation and capacity data

Generic country clusters

Northen Europe and the Baltics

- Denmark
- Estonia
- Finland
- Ireland
- Latvia
- Lithuania
- Sweden
- United Kingdom

Central-eastern Europe

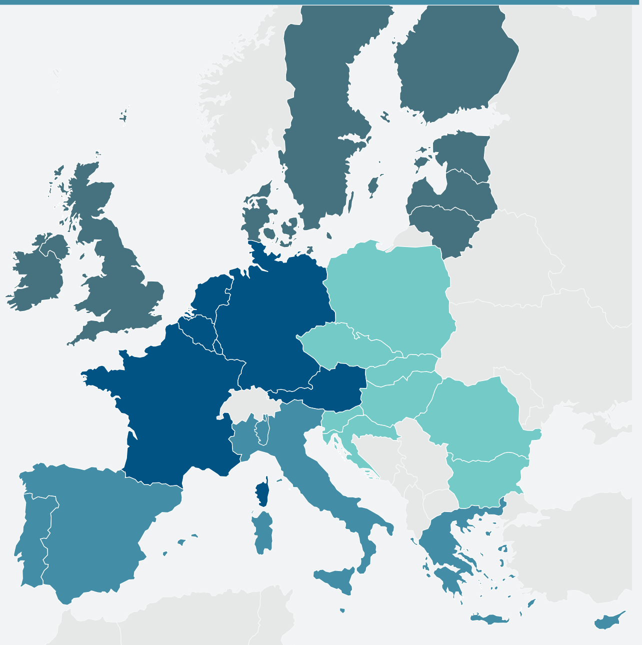
- Bulgaria
- Croatia
- Czech Republic
- Hungary
- Poland
- Romania
- Slovakia
- Slovenia

Central-western Europe

- Austria
- Belgium
- France
- Germany
- Luxembourg
- Netherlands

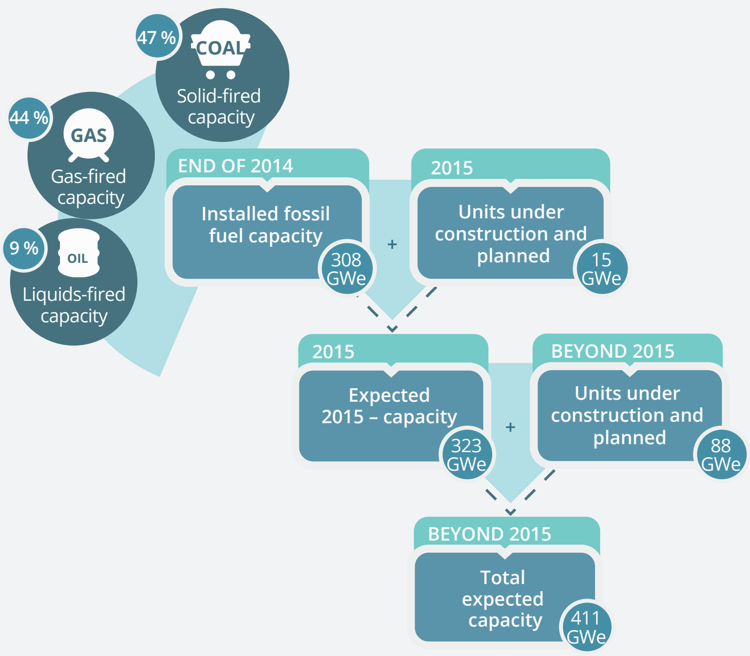
South and south-eastern Europe

- Cyprus
- Greece
- Italy
- Malta
- Portugal
- Spain



The regional aggregation in this study is illustrated above (for details, see Section 1.3.2, Scope and limitations).

Fossil fuel capacity across the EU-28



Capacity assessed in this study: at the end of 2014, the EU's **installed** fossil fuel capacity ≥ 200 MWe equalled 308 GWe. If units that were planned and under construction in 2015 are included (15 GWe), the **expected 2015 capacity** reaches 323 GWe. If new units planned beyond 2015 are also included (88 GWe), it increases to 411 GWe (the **total expected capacity**, i.e. the maximum capacity assessed in this study, obtained when all units are summed, irrespective of their commissioning date). Solid fuel- and gas-fired capacity as proportions of total installed 2014 capacity are similar (47 % and 44 %, respectively), while the proportion of liquids-fired capacity is smaller (9 %).

Main findings

1. ***A large part of the EU's coal-based power capacity is near the end of its lifetime. From an assets management perspective, this is an opportunity to decarbonise the sector***

Almost three quarters of all solid fuel-fired capacity is 25–35 years old, or more. In contrast, gas-fired capacity is considerably younger, almost four fifths of it having been in place for 15 years or less. Oil-fired capacity is relatively old, with four fifths of it having been constructed before 1980 and almost all the remaining capacity having been commissioned before 1989.

As natural gas-fired capacity is generally half as carbon intensive as coal-fired capacity and technologically more suited to supporting the integration of variable renewable energy sources into the electricity grid because the output can be more easily varied, the age profile of the EU's capacity presents an opportunity for decarbonisation when the sector is viewed from a European perspective.

2. ***One quarter of the new fossil fuel capacity in Europe could come from coal***

According to commercially available information (Platts, 2014), across the EU there is a significant amount of new fossil fuel-based capacity under way (88 GWe), either already under construction or planned. Gas constitutes three quarters of the new fossil fuel-based capacity. Coal-based capacity (i.e. solid fuels) makes up the remaining quarter, while oil-based power generation will almost disappear when existing oil-fired units are decommissioned.

3. ***At present, operators tend to extend the lifetime of their fossil fuel capacity***

The medium and old age of many of the fossil fuel units assessed, and the fact that few new units were installed during the 1990s, indicates that the expected lifetime of the operating units is increasing compared with historically observed average lifetimes.

To obtain the hypothetical evolution of the fossil fuel power sector from a technical lifetime perspective, the remaining lifetime of each operational and planned unit was calculated. Two illustrative profiles were calculated based on the assumption of (1) a continuation of the recent longer lifetimes (extended lifetimes — EXT profile), and (2) a return to historic average power plant lifetimes (AVG) (see Table ES.1 and note to Figure ES.1).

Implementing the average lifetime values in the AVG profile, however, resulted in one third of all operational fossil fuel capacity being decommissioned in 2015. A decommissioning rate near this level was not observed in practice. This implies that current fossil fuel units are already operating for longer than they used to in the past.

4. ***A sustained tendency of operators to extend the lifetime of fossil fuel power plants would clash with the EU's decarbonisation efforts***

Currently, the EU is progressing well towards its 2020 climate and energy targets (EEA, 2015b). However, if the existing and planned units operate in accordance with extended lifetimes (EXT profile), this would result in excess fossil fuel capacity in both 2020 and 2030 compared with the cost-effective capacity levels in the Energy Roadmap 2050: by 48–51 GWe in 2020 and by 56–66 GWe in 2030 (roughly one fourth of the capacity in the EXT profile would be in excess in 2030), as illustrated in Figures ES.1 and ES.4. Overcapacity would also arise if the existing and planned units operated in accordance with average lifetimes (AVG profile); however, in this case the cost-effective levels in the Roadmap would be surpassed by much less in 2030 than they would be in the case of the extended lifetimes (EXT profile).

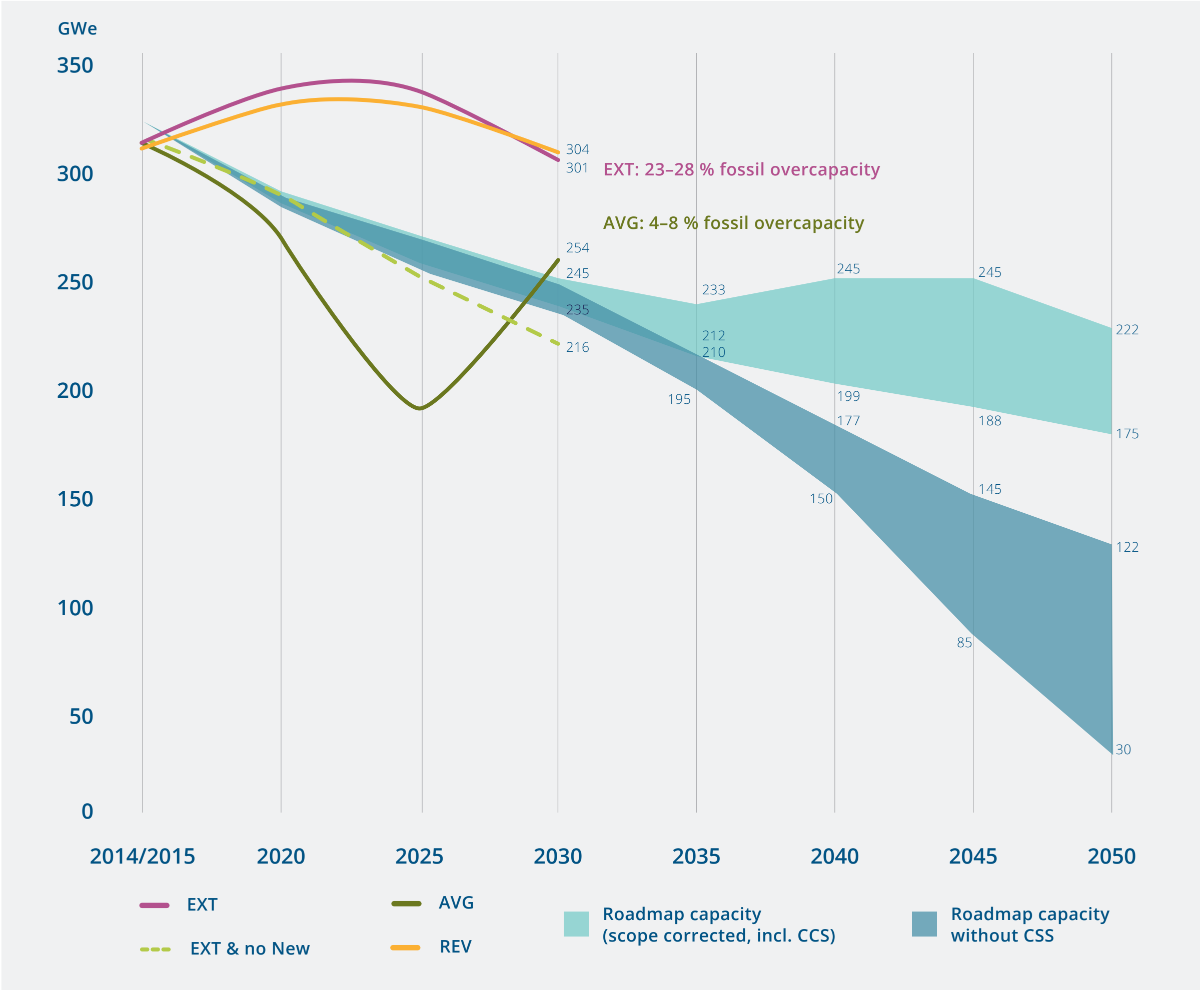
When assessing capacity by fuel type, in the bottom-up assessment with extended lifetimes, solid fuel-fired capacity would be consistently higher than the capacity in the Roadmap — with up to 30 GWe of potential stranded assets by 2030 under the revised (REV) profile.

Assuming that the extended capacity lifetimes become a reality, the risk of fossil fuel capacity lock-in, or of stranded assets, would have emerged by 2020 in all regions and would have grown further by 2030.

Since the adoption of the Roadmap, the prospects for developing carbon capture and storage (CCS) technologies by 2030 have declined significantly: to date, none of the 12 large-scale EU CCS demonstration projects that were expected to be up and running by 2015 is in place. Under these circumstances, not only would the projected CCS capacity levels in the Roadmap be insufficient to tackle GHG emissions from excess fossil fuel capacity. In reality, the actual CCS capacity levels are likely to be smaller too, due to the current delays. That will have implications for the fossil fuel capacity that can be fitted with CCS technology, while converting some of that overcapacity to run on biomass could exacerbate the pressure on natural resources and raise questions about sustainability.

Assuming average capacity lifetimes, the old capacity, constructed before 1980, would rapidly disappear as it reaches the end of its lifetime. Up to 2025, more old

Figure ES.1 Illustrative sector capacity profiles and cost-effective capacity levels from the Energy Roadmap 2050 scenarios



Note: EXT: the sectoral profile based on the assumption of currently expected, longer (extended) lifetimes, derived from the increasingly long lifespans observed so far in practice.

AVG: the sectoral profile based on the assumption of historic average lifetimes. The implementation of average lifetime assumptions in AVG leads to a significant rate of decommissioning already by 2015 (30 %) and to the complete disappearance of capacity older than 35 years after 2020. Worth noting is that even the AVG profile ends up in 2030 with excess capacity due to planned new capacity additions.

REV: the sectoral profile based on the assumption of extended lifetimes, but taking into account possible retrofits and closures due to the IED.

EXT & no New: the extended lifetime profile under the assumption of no new fossil capacity additions post 2015.

Source: EEA (based on EC, 2011c; Platts, 2014; the LCP-EPRTR and ETS databases and own calculations).

capacity would be decommissioned than new capacity constructed. This would result in an initial sharp decrease in fossil fuel capacity, followed by an increase in capacity after 2025 (see AVG profile in Figure ES.1), as by then more new capacity would have been installed than old capacity decommissioned. By 2030, the assumption of average lifetimes would lead too to excess fossil fuel capacity (9 GWe).

The importance of the two illustrative profiles (EXT and AVG) is twofold. On the one hand, they question the consistency between plans to expand or retrofit fossil fuel capacity and national and EU-wide decarbonisation measures. On the other hand, they illustrate that it is necessary to adopt a sector-wide perspective to ensure rational decommissioning of fossil fuel capacity, in line with the existing transformation goals for the sector.

5. ***Modernising power plants to comply with EU legislation on air pollutants would marginally affect the overall fossil fuel capacity, but it would slightly increase the excess in solid fuel-fired capacity***

Given the old age of many units in the power sector, without further action, a relatively large noncompliance with the emission limit values (ELVs) for certain air pollutants set under the IED is to be expected. From the installed fossil fuel capacity, the EEA analysis of the requirements for technological upgrading to meet future ELVs set under the IED identified that about 37 % of the capacity (113 GWe — especially older coal plants) would exceed either the NO_X (nitrogen oxides) or the SO_2 (sulphur dioxide) ELVs, or both, based on the actual emissions reported in 2012.

To ensure compliance with the strengthened ELVs, operators will have to decide in these cases whether or not to make further investments to upgrade their current fossil fuel plants. If implemented, these upgrades could extend the technical lifetime of the respective capacity.

To illustrate the potential consequences of these decisions on the hypothetical evolution of the power sector, a revised sectoral lifetime (REV) profile was constructed using extended lifetime assumptions. This profile was based on the information available in the context of the LCP and IED Directives and on additional information received directly from Member States in the context of this project (the European Environment Information and Observation Network, or Eionet, consultation). The resulting information suggests that many of today's fossil fuel power plants will be upgraded technologically to comply with the IED, and thus they will continue to operate after 2020.

Compared with the EXT profile, the REV profile would lead to an initial decrease in capacity by 2020, as some existing capacity would be decommissioned. This would then be followed by a small increase (+ 3 GWe) by 2030, due to technological upgrading to meet the IED ELVs ([3]). Taking into account the installed and planned capacity and the retrofits under the REV profile, the excess fossil fuel capacity would range between 41 and 44 GWe by 2020 and between 59 and 69 GWe by 2030.

The REV profile thus illustrates that the technological upgrades would lead to only a marginal strengthening of the capacity lock-in across the EU, by roughly 3 GWe in 2030 compared with the hypothetical EXT profile.

As both the EXT and the REV profiles result in considerable overcapacity compared with the Roadmap levels, a more detailed assessment was made of overcapacity by fuel type. It showed that by 2030 solid fuel- and gas-fired capacity levels in the EXT profile would be about 30 % greater than the equivalent capacities in the Roadmap. In absolute terms, however, excess gas-based capacity in the EXT profile would be twice as high as the solid fuel-fired overcapacity (see Table 4.2), a situation deemed less problematic from a climate perspective than if most overcapacity were to be solid fuel fired. Oil-based capacity levels would be lower than those in the Energy Roadmap 2050, because beyond 2015 there are hardly any plans to construct new oil-fired capacity.

In the REV profile, a slight increase in the excess solid fuel-fired capacity would be observed in 2030 (36–38 % in excess of the cost-effective solid fuel capacity level). This is due to technological upgrading to comply with EU legislation on air pollutants and the 20-year average lifetime extension associated with retrofits (see Section 1.3.3, Lifetime assumptions).

6. ***Central-eastern Europe and south and south-eastern Europe are at a lower risk of solid fuel-fired capacity lock-in***

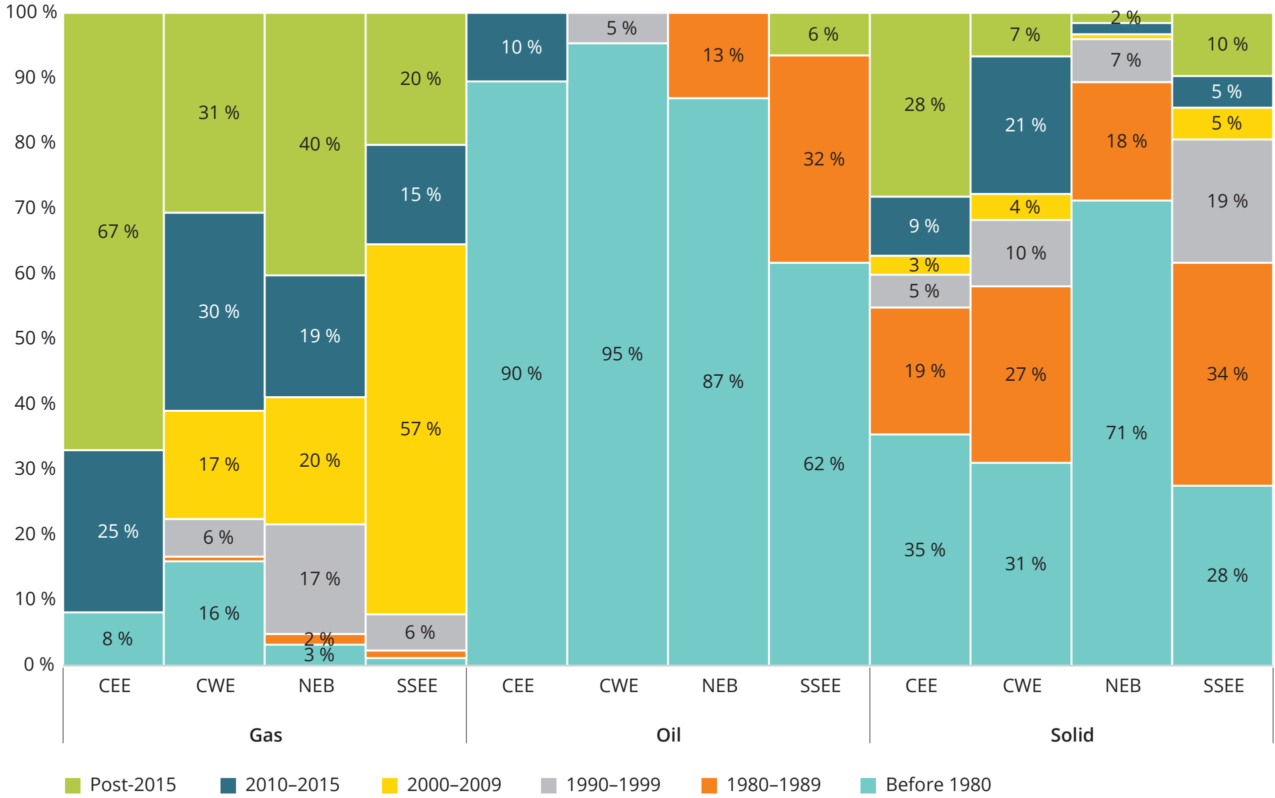
The age of the assessed capacity differs considerably by region, with the oldest capacity located in central-eastern Europe (CEE) and the newest found in south and south-eastern Europe (SSEE) (Figure ES.2).

Across all regions, plans for new fossil fuel capacity after 2015 are similar, in the range of 20–23 GWe, as shown in Figure ES.3. In absolute terms, the greatest expansion in gas-fired capacity would be in northern Europe and the Baltics (NEB) (23 GWe), which would see almost no new solid fuel based capacity. The greatest expansion in solid fuel-fired capacity is planned in CEE (13 GWe).

Nevertheless, when compared with the Roadmap levels for solid fuels, CEE does not appear to run the risk of a significant solid fuel-fired capacity lock-in (see Table 4.4). This is because a large proportion of the old capacity is expected to have been decommissioned by 2030. The risk of a solid fuel-fired capacity lock-in is lower also in SSEE (+ 2–3 GWe, or roughly 10 % above the Roadmap levels), owing to only a few new coal-fired units being planned in this region (+ 3 GWe).

([3]) According to the REV profile, approximately 12 % of the total operational capacity in 2014 could potentially be closed by 2024, while 25 % of the operational capacity in 2014 could be renovated to comply with the IED ELVs (taking into account the expected lifetime set and the planned new capacity).

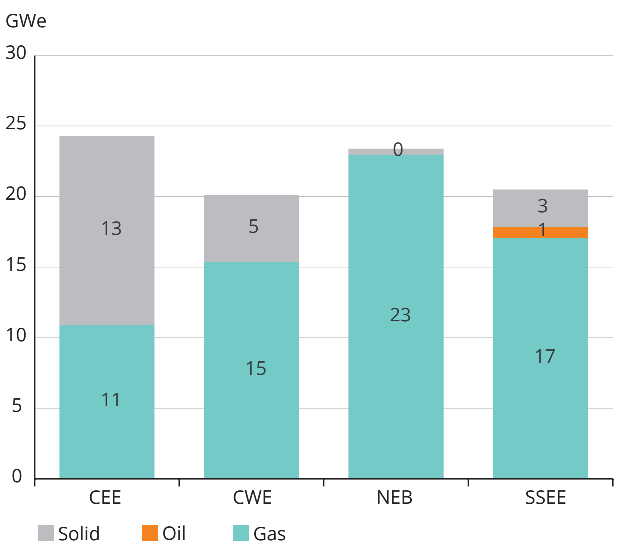
Figure ES.2 Age of capacity by fossil fuel type, by region



Note: Includes all installed and expected new units ≥ 200 MWe (all statuses).

Source: EEA (based on Platts, 2014).

Figure ES.3 New fossil fuel capacity post-2015, by region in the EU-28



Source: EEA (based on Platts, 2014).

By 2030, the greatest risk of a lock-in in solid fuels, in absolute terms, is to be found in central and western Europe (CWE) (+ 18 GWe, or roughly 65 % in excess of the cost-effective Roadmap levels), followed by NEB (+ 7 GWe, or about 84 % above the levels identified in the top-down analysis).

Interestingly, for NEB the risk of stranded solid fuel fired capacity is closely linked to the anticipated technological upgrading to reduce emissions of air pollutants in accordance with the IED. In CEE, however, the same level of technological upgrading would result in only a minor increase in potentially stranded solid fuel fired capacity (+ 2 GWe), whereas in CWE and in SSEE it would lead to a slight decrease in excess coal-fired capacity compared with the units being decommissioned in line with their extended technical lifetimes. In practice, this could mean that more decommissioning of capacity than retrofitting is planned in order to meet the IED ELVs.

Considerations

This report assesses the importance of capacity lifetimes and planned expansions in capacity for the hypothetical evolution of the power sector in Europe and the resulting alignment of the sector with EU climate goals. Because its purpose is to highlight the importance of a rational, progressive decommissioning of fossil fuel capacity across the EU, the analysis is not geared towards forecasting future interactions between installed capacity, on the one hand, and EU climate and energy policies and evolving macro-economic and market conditions (e.g. the evolution of international fossil fuel prices), on the other hand.

Drawing on the assessment, the following policy considerations are made:

- ***Seek out the least-cost, pan-European approach to decarbonising the power sector***

In terms of overall efforts, keeping the power sector transition in Europe on the cost-effective pathway outlined by the Energy Roadmap 2050 would require the removal of 20–24 % of all EU fossil fuel capacity up to 2030 (Figure ES.4). Active decommissioning of carbon-intensive, inflexible baseload capacity would facilitate the integration of higher shares of variable renewable energy sources into the sector. Alignment with the Roadmap would mean a 45 % reduction in the installed coal-fired capacity by 2030 compared with the installed capacity in 2014, while gas-fired capacity could increase by 6–11 % over its 2014 levels.

To prevent unsustainable future levels of fossil fuel overcapacity, avoiding the commissioning of new fossil fuel units (in particular coal) and decommissioning the old, existing units would be essential. As illustrated in Figure ES.1, if building the currently planned new fossil fuel capacity was accompanied by the decommissioning of the same amount of existing capacity, the fossil fuel capacity would be aligned with the levels in the Energy Roadmap 2050 (see the 'EXT & no New' profile). This would, however, require firm action to be taken within the current decade. In this respect, decommissioning first those plants that would require investment in order to comply with the IED could free up financial resources for alternative investments in low-carbon technologies. Such a strategy would be particularly beneficial, given the impact of the recent financial crisis on the availability of finance for renewable energy investments across the EU. In contrast, if power plant operators were to continue extending the lifetime of their installed capacity, the EU's fossil fuel capacity would become increasingly excessive.

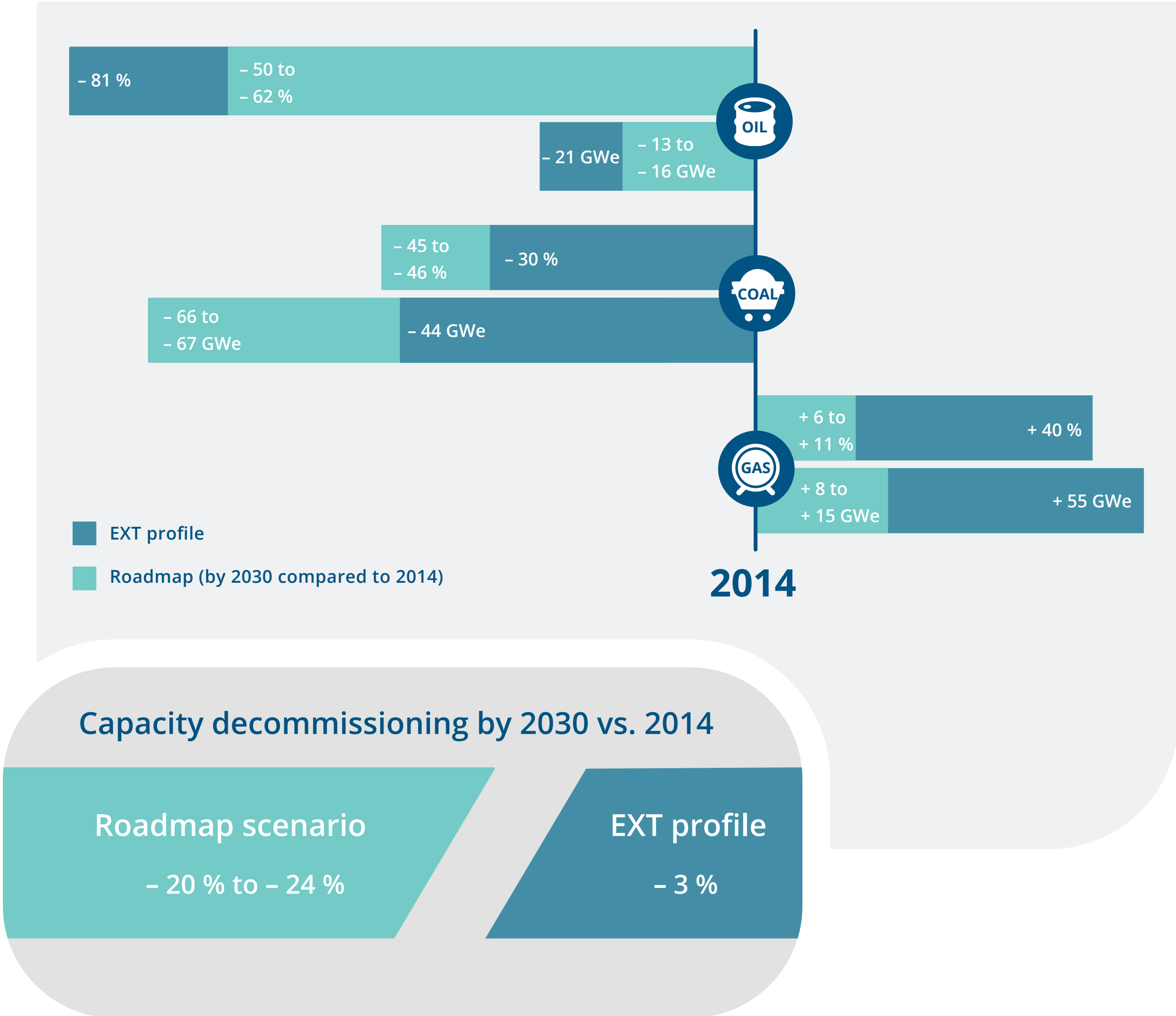
The illustrative evolution of the sector towards fossil fuel overcapacity under the chosen lifetime assumptions puts an emphasis on the significance of longer term public and private sector planning, as well as a commitment to progressively decommission fossil fuel capacity to ensure that the sector is decarbonised at the lowest overall cost to consumers. Yet, a number of near-term decisions, concerning new fossil fuel capacity additions or modernisations, and the potential introduction of capacity mechanisms to maintain or increase the security of electricity supply, risk promoting the opposite, namely fossil fuel capacity additions and lifetime extensions that could perpetuate the demand for capacity payments and distort the efficient functioning of the integrated EU electricity market. Such interventions should be considered only as a last resort, if the reformed EU electricity and carbon markets fail to address concerns over the adequacy of electricity generation. Where implemented, such interventions ought to be made consistent with EU and national long-term decarbonisation pathways.

- ***Provide early information and long-term projections for the evolution of fossil fuel capacity, as part of the integrated climate and energy plans under the EU Energy Union***

Under the applicable EU climate legislation, Member States are already required to prepare and update biennially GHG emission projections up to 2020 and low-carbon development strategies up to 2050 ([4]). The drawing up of integrated national energy and climate plans — currently under discussion between the European Commission and the Member States as part of the governance structure under the Energy Union — could provide the right framework for Member States to include early information available to competent authorities on the projected evolution of power capacity and planned closures by fuel type for the period 2021–2030 and provide longer term strategic planning up to 2050. Providing such information, along with information on expected carbon-intensity levels and existing and planned policies and measures, could improve the consistency between national 2030 climate and energy strategies, increase regulatory stability as a prerequisite for longer term investments, and enable Member States to contribute to the EU electricity market more efficiently through interconnections and the use of cross-border capacities and demand-side approaches.

([4]) The Monitoring Mechanism Regulation (MMR) (Regulation No 525/2013).

Figure ES.4 Capacity by fuel in 2030 vs. 2014 (Roadmap and EXT, EU-27)



- ***Increase the alignment of energy, climate and environmental policies to speed up the transition to a secure and sustainable EU power sector***

From an EU policy perspective, the IED is expected to have only a small overall effect on existing fossil fuel capacity, as shown in Figure ES.1. Consequently, preventing the unsustainable build-up in fossil fuel capacity in the EXT and REV profiles relies, indirectly, on the effective functioning of the EU ETS. As discussed elsewhere (EEA, 2015c), the EU carbon market faces challenges in the form of a large surplus of allowances that has accrued over time and low carbon prices. As these conditions could affect the ability of the ETS to send clear signals to operators and investors regarding the envisaged long-term decarbonisation of the power sector, solutions need to be found to tackle the surplus allowances so that the ETS price becomes effective much earlier than 2030. To that end, the ongoing revision of the ETS should take into account the risk of future fossil fuel capacity lock-in owing to current plans to expand and to retrofit fossil fuel capacity.

1 Introduction

1.1 Background

1.1.1 EU policy landscape

The EU and its Member States have put in place and consolidated a number of decarbonisation policies and initiatives that create a framework for transition towards a low-carbon and resource-efficient European economy (see Box 1.1). Within that framework, the European Commission roadmaps aim to create clarity and transparency regarding the **necessary, manageable and cost-effective medium- and long-term transitions** away from the current fossil fuel-based energy system.

Two European Commission roadmaps are particularly important for this report:

- the 'Roadmap for moving to a competitive low carbon economy in 2050', as it sets out cost-effective sectoral trajectories to reduce carbon dioxide emissions by 2050, with mid-term reviews in 2030 and 2040 (EC, 2011a);
- the Energy Roadmap 2050, as it sets out competitive and energy-secure decarbonisation scenarios for the EU energy sector, with a focus on power generation.

The power sector is at the heart of Europe's decarbonisation strategy and it is also the focus of this report.

In 2014, power generation remained the largest greenhouse gas (GHG)-emitting sector in Europe, being responsible for roughly one third of all energy-related emissions and more than half of the verified emissions under the EU Emissions Trading Scheme (ETS) (EEA, 2015a; IEA, 2015). The sector's strong reliance on fossil fuels and the availability of low-carbon substitutes mean that it could be decarbonised more rapidly and economically, compared with other sectors (EC, 2011b).

Box 1.1 Medium- to long-term EU climate and energy objectives

The EU Climate and Energy Package of 2009 set three main targets for 2020: a 20 % reduction in GHG emissions (compared with 1990), a 20 % share of renewable energy sources in energy consumption, and 20 % improvement in energy efficiency.

In January 2014, the European Commission proposed medium-term targets for 2030: a 40 % reduction in GHG emissions (compared with 1990), a 27 % share of renewable energy consumption, and a 27 % improvement in energy efficiency.

To limit climate change to below 2 °C, EU leaders have endorsed the objective of reducing Europe's GHG emissions by 80–95 % by 2050, compared with 1990 levels, as part of measures taken by developed countries as a group to reduce their emissions by a similar degree. In line with this long-term objective, GHG emissions in the EU power sector need to fall by 48–66 % by 2030 and by 90–98 % by 2050 compared with 2005.

The 'Roadmap for moving to a competitive low carbon economy in 2050', the Energy Roadmap 2050 and the Transport White Paper reflect the EU's goal to reduce GHG emissions in the run-up to 2050, with a 54–68 % cut in emissions by 2030 and an 80–95 % reduction by 2050, both compared with levels in 1990.

These targets, set at the macro-level, have profound implications for the — largely fossil fuel-based — EU power sector and should set out the requirements for a huge cross-sectoral transformation. The vision is that electricity should come almost entirely from renewable sources, nuclear power plant units and fossil fuel power plant units equipped with CCS technology.

The EU's medium-term climate and energy targets represent sectoral transformation benchmarks (EC, 2009, 2014) against which policy effectiveness and coherence can and should be assessed.

For the power sector, the Energy Roadmap 2050 illustrates how currently available climate mitigation options could deliver a 90–98 % cost-effective decarbonisation, compared with 2005, by 2050 (EC, 2011b, 2011c). Those scenarios, however, are neither binding nor a substitute for EU, national and local measures.

At the EU level, GHG emissions from the power sector and from other energy-intensive industrial sectors and commercial airlines are regulated by the ETS, which ensures that the emissions of these sectors decline in line with an annually decreasing EU-wide emissions cap. According to the projections that the Member States submitted in 2015 under the EU reporting regulation, with the existing measures in place, emissions from stationary installations under the EU ETS will decrease by 8 % between 2015 and 2020, and by a further 5 percentage points between 2020 and 2030 (EEA, 2015b).

However, although the GHG emissions from the installations under the ETS are falling as intended, the ETS faces challenges in the form of a large surplus of allowances that has accrued over time and low carbon prices. Together, these conditions are a disincentive to long-term investment in low-carbon technologies and could affect the ability of the ETS to meet more demanding emission reduction targets cost-effectively.

To address this imbalance, the EU has postponed the auctioning of 900 million allowances until 2019–2020 and decided to establish a market stability reserve (MSR) for the ETS, to make the system more resilient in the face of imbalances in supply and demand (EC, 2015). In addition, in 2015 the Commission tabled a proposal for a wider review of the EU ETS, including an increased rate of reduction in the ETS cap beyond 2020. This proposal is currently being negotiated by the European Parliament and the Council through the ordinary legislative procedure.

1.1.2 The sector and the investors' perspective

Along with nuclear energy, fossil fuels — coal and gas — still represent a key energy source for the European power system. In 2014, conventional fossil fuel electricity generation accounted for a bit less than half of the electricity produced in the EU. Between 1980 and 2008, it increased continuously and thereafter decreased irregularly due to the growing output from renewable energy sources [5] and the consequences of the economic crisis of 2007–2008. In 2013, fossil fuel electricity generation decreased by 5.9 % year on year in the EU; nuclear electricity generation decreased by 0.6 % year on year and accounted for 26.9 % of the total production.

Between now and 2020, the owners of fossil fuel plants will need to take important decisions regarding their current and planned capacity and ensuing investments. These decisions will be taken in the face of considerable uncertainty and in a context in which:

- The total GHGs that can be emitted by the power sector is constrained and should decrease linearly in accordance with the ETS cap. The stringency of this cap will depend on the effectiveness and speed at which the MSR and the wider review of the EU ETS, currently under negotiation, succeed in tackling the oversupply of allowances.

- Electricity consumption in Europe has broadly remained flat since 1990, and it may not increase significantly until 2030. Moreover, for 2020 and 2030 there are binding targets for the consumption of renewable energy and non-binding targets for improvements in energy efficiency. Together, these factors are likely to affect the need for fossil fuel-based power generation.

- An increasing number of Member States are taking action to secure their electricity supplies and prevent potential black-outs by introducing capacity mechanisms. These offer additional rewards to capacity providers, on top of income generated by selling electricity, in return for maintaining existing capacity or investing in new capacity needed to guarantee the security of the electricity supply. Where implemented, national capacity markets (will) have an impact on competition and on the decisions taken by individual power plant owners and investors to install, maintain or decommission fossil fuel capacity.

- As the energy sector contributes significantly to harmful air pollution (EEA, 2014a), the Industrial Emissions Directive (IED) is making the emission limit values (ELVs) for certain air pollutants more stringent. Those plants that do not meet the revised ELVs will need to be either upgraded technologically to become less polluting or decommissioned. But technological upgrading may also mean extending their technical lifetime.

(5) The share of renewable energy sources in gross electricity consumption in the EU-28 increased by 8 % year on year between 2008 (17 %) and 2014 (27.5 %), driven by a rapid growth, especially in wind power and solar photovoltaic systems (EEA, 2016).

Box 1.2 Bottom-up sector capacity and projections of power and CO_2 outputs

The bottom-up sector capacity was obtained by adding up all operational units (OPR), units under construction (CON), delayed units (DEL) and planned units (PLN) up to a given year, from which the capacity of those units expected to have been decommissioned by that year could be extracted.

To project the illustrative electricity generation and annual CO_2 emissions of the power plant units in the bottom-up analysis into the future, the then-operational plants were considered and load factors (based on the average load factors per fuel type in 2014) and fuel-dependent IPCC emission factors were assigned to them to determine the requisite outputs.

For then-operational plants that are also currently operational, real CO_2 outputs — as reported in ETS 2012 — were used, along with IPCC emission factors to determine energy output. If these energy outputs delivered a load factor > 0.9 compared with capacity, the emissions factors were deemed inaccurate and a load factor averaged over the study database was used instead (additional information on this assessment is provided in Annex 1). These average load factors were also used for then-operational plants that are not currently operational, in order to determine the energy outputs. The CO_2 emissions of these plants were calculated using the aforementioned emissions factors.

1.2 Purpose

This report aims to fill an important information gap by illustrating the potential size of the excess fossil fuel capacity by 2030, assuming continuing inertia in the power sector. This has been done by calculating hypothetical future profiles for the evolution of the fossil fuel power sector in Europe up to 2030, on the basis of selected lifetime assumptions, and then comparing these with the scenarios for cost-effective power sector decarbonisation in the Energy Roadmap 2050. The principal aim is to understand the convergence, or the risk of lock-in, of the hypothetical profiles, with respect to the decarbonisation scenarios in the Roadmap and, more widely, with the EU's long-term decarbonisation objectives.

By examining in detail the fuel type, status and age of the existing and planned fossil fuel capacity, and linking this information to company ownership, the report also aims to contribute to a better understanding of the power sector and to provide useful information for investors and policymakers.

Last but not least, the report looks into technological upgrading needs across the sector to comply with stricter ELVs under the IED. In essence, these requirements for upgrading needs signal the potential need for investment and, where realised, mean extending the lifetime of the upgraded capacity into the future. By exploring the consequences of the IED on capacity lifetime and, thereby, on the potential evolution of the power sector, this report contributes to a better understanding of policy and, in particular, to a broadening of our understanding of the coherence between climate and industrial emissions policies.

1.3 Assessment framework

1.3.1 Method

The assessment is based on an innovative approach and recent, detailed power sector data that give a robust quantitative insight into the fossil fuel power sector at EU and regional level. The analytical framework builds on a detailed, unit-by-unit and plant-by-plant investigation of the current structure and GHG profile of the EU power sector, carried out through a 'bottom-up assessment'.

The bottom-up assessment draws in particular on the Platts World Electric Power Plants (WEPP) 2014 database, which has been linked to other information sources, especially the Large Combustion Plants dataset and the European Pollutant Release and Transfer Register dataset (LCP-EPRTR), managed by the EEA and the European Commission ([6]), the European Union Transaction Log (EUTL) dataset under the ETS, and the Power Plants Tracker (PPT) database of Enerdata.

The risk of a fossil fuel lock-in is exemplified as **excess fossil fuel capacity** in the illustrative power sector profiles developed for this report, compared with the cost-effective levels in key mitigation scenarios in the

([6]) The LCP-EPRTR database contains data reported by EU Member States to the Commission under the European Pollutant Release and Transfer Register (E-PRTR) Regulation and the Large Combustion Plants (LCP) Directive.

Energy Roadmap 2050 impact assessment (EC, 2011c). Comparisons of cost-effective and illustrative rates of decommissioning, and of optimal and illustrative carbon intensity levels, are also shown to highlight the ensuing misalignment should the (excess) capacity continue generating electricity at current levels.

First, to obtain the hypothetical evolution of the fossil fuel power sector, the remaining lifetime of each operational and planned unit was calculated. Two illustrative profiles were calculated based on (1) currently expected, longer, lifetimes (extended lifetimes — EXT profile), assuming the increasingly long lifetimes currently observed in practice; and (2) medium or average power plant lifetimes (AVG profile), assuming no further extension. The lifetime values were derived from the literature, an assessment of the average age of already retired units (based on Platts, 2014), and an assessment of the average, currently expected lifetime of units (based on PPT, 2015).

Second, a specific assessment of technological upgrading needs across the sector to reduce emissions of air pollutants and comply with the IED was carried out. This complementary assessment was necessary because — in the absence of further incentives to limit or reduce power generation from fossil fuels, such as higher carbon prices under the EU ETS — such upgrades could result in extended lifetimes for modernised capacity (and therefore a stronger lock-in) or a higher risk of stranded capacity due to the financial investment required for upgrading. The assessment led to the calculation of the illustrative revised (REV) profile, based on the assumption of the extended lifetimes (EXT profile) but taking into account possible retrofits and closures to comply with the IED. The initial results of the REV profile were revised with the help of Member States in 2015. While not all countries consulted seemed to have this information available, the revision made it possible to take stock of the most recent national intentions, discussions and plans.

Third, variants of the above profiles were constructed in order to assess the hypothetical evolution of the sector in the event that no planned fossil fuel capacity would be constructed after 2015.

The illustrative profiles are constructed to give the best possible reflection of the current key drivers for the sector. However, the bottom-up assessment method should not be confused with model-based forecasting, as it does not attempt to reproduce dynamically the evolution of factors that determine capacity lifetime (see Section 1.3.2, Scope and limitations).

Comparison with the Energy Roadmap 2050 scenarios

The main focus of the assessment is on the current power plant units, as well as the units planned up to 2030, with the analysis being targeted at the medium term. The Energy Roadmap 2050 scenarios project 54–60 % renewable energy (net) capacity by 2030 and 7–9 % nuclear capacity. This would lead to 52–61 % of net power generation from renewable sources and 15–21 % from nuclear energy (depending on the scenario). Given the scope of this study, the focus is on the remaining installed capacity consisting of oil, gas- and solid fuel-fired units, which, according to the Energy Roadmap 2050 scenarios, should account for 24–27 % of net electricity generation by 2030.

Three Energy Roadmap 2050 (top-down) scenarios are used in the study to identify potential excess capacity. The first models a strong contribution from all low-carbon technologies — including nuclear energy and CCS — and is known as diversified supply technologies (DST). The second models a greater role for renewable energy sources (a high RES contribution).

Box 1.3 Comparability adjustment of Energy Roadmap scenarios

The bottom-up analysis focuses only on fossil fuel power plant units with a minimum threshold of 200 MWe or more. Thus, nuclear and renewable capacity were removed from the Roadmap scenarios and the Roadmap scenarios were adjusted to cover only power plant units ≥ 200 MWe to create an approximate representation of the bottom-up technology mix. This was done by using the proportions of each fuel compared with the total (for units ≥ 200 MWe), according to Platts (2014). Accordingly, an adjustment factor of 66 % by output capacity was used for gas, 43 % for oil and 75 % for coal.

Values for CO_2 emissions and electricity generation were also adjusted. The ETS emissions linked to the bottom-up database account for 92 % of the emissions expected from fossil fuel electricity generation in the Energy Roadmap scenarios. In order to adjust the Roadmap scenarios and make them comparable with the bottom-up sectoral profiles, it was assumed that 10 % of the expected thermal generation and GHG emissions will continue to be covered by smaller units below the 200 MWe threshold. Thus, in this assessment it has been assumed that the bottom-up sectoral profiles will correspond to only 90 % of the projected power generation levels in the Roadmap scenarios.

Box 1.4 Summary of selected Energy Roadmap 2050 scenarios:

- *Diversified supply technologies (DST)*. No technology is preferred; all energy sources can compete on a market basis with no specific support measures. Decarbonisation is driven by carbon pricing, assuming public acceptance of both nuclear and CCS technologies.

- *High energy efficiency (EE)*. Political commitment to very high energy savings; it includes, for example, more stringent minimum requirements for appliances and new buildings, high renovation rates of existing buildings, and establishing obligations for energy utilities to make energy savings. This leads to a decrease in energy demand of 41 % by 2050, compared with the peaks in 2005–2006.

- *High renewable energy sources (RES)*. Strong support measures for RES leading to a very high proportion of RES in gross final energy consumption (75 %) and in electricity consumption (97 %) in 2050.

The data originate from the Energy Roadmap 2050 and are directly based on the PRIMES model. The model calculates net generation, while the bottom-up assessment provides the gross generation. Typical auxiliary power consumption depends on the type of plant but ranges between 1–3 % of gross generation for gas plants and 6–8 % for coal-fuelled plants. No adjustments were made, given the limited impact; however, this aspect should be considered when comparing the bottom-up generation values with the Roadmap scenarios' net generation values.

The third models a greater role for energy efficiency and demand-side management among the other mitigation options (high energy efficiency (EE) contribution).

These three Roadmap scenarios were selected as the basis for the comparison due to their level of detail and wide acceptance. Working with the ranges that correspond to these scenarios avoids potential discussions regarding particular assumptions. Detailed assumptions for these scenarios are presented in the Impact assessment — Energy Roadmap 2050 (EC, 2011c).

1.3.2 Scope and limitations

Capacity in focus

The bottom-up assessment covers power plant units located in the EU-28, using oil, natural gas and coal (and co-fired/biomass units), of 200 MWe capacity and above. The focus is thus on large and typically long-lived baseload fossil fuel capacity. This amounts to 1 067 units across the EU-28, providing 411 GWe of capacity (including operational and planned units) in the current bottom-up assessment ([7]).

The capacity threshold implemented ensured that the effort involved in linking various databases remained reasonable, as the focus was set on large units, which tend to contribute more to energy generation and GHG emissions, as they are typically operated as baseload. The threshold captures more than two thirds of all EU-wide operational and planned fossil fuel units.

Precisely, the power plant units that are subject to the bottom-up analysis in this report:

- are located in the EU-28;
- are currently operational and planned ([8]);
- use one of the following fuel types: oil, natural gas, coal and co-fired coal/biomass units (biomass is not included as primary fuel) and uranium ([9]);
- have an electricity-generating capacity of 200 MWe or higher ([10]).

([7]) When comparing the bottom-up approach with the Roadmap scenarios, the EU is represented as the EU-27 (without Croatia) in order to ensure consistency with the Roadmap assessment, which does not include Croatia.

([8]) Statuses considered in the present assessment are: under construction (CON); deactivated, mothballed (DAC); delayed (DEL); operational (OPR); and planned (PLN).

([9]) Although the aim of this study was to assess the degree of carbon lock-in in the current power sector, nuclear units (which do not emit CO_2 when operational) were part of the bottom-up database, providing a more complete picture of the power sector. The present analysis tended to exclude uranium capacity and energy in order to draw the most relevant conclusions on the state of carbon lock-in, although uranium units are sometimes considered when, for example, discussing the current sectoral capacity in Chapter 2.

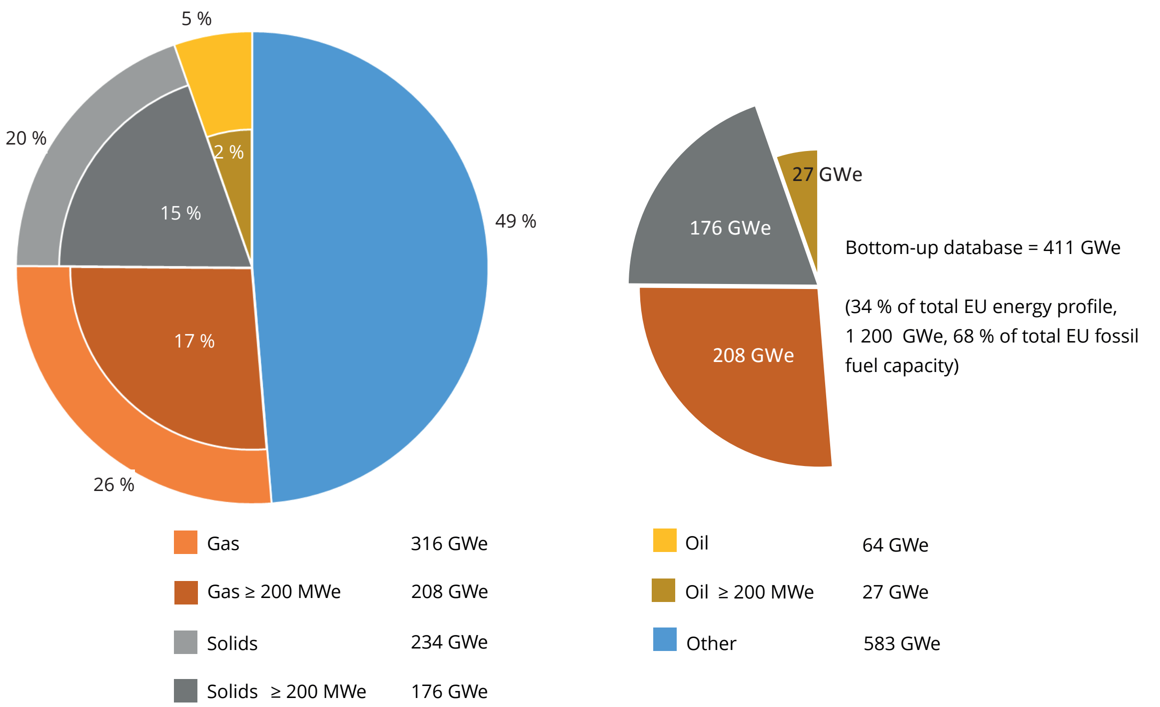
([10]) The Platts WEPP database was used as starting point for the analysis. The above-mentioned selection criteria were applied to this database. To retrieve more specific data on the selected units, a link to the corresponding plants available in the complete LCP-EPRTR dataset was made, thus avoiding any selections on capacity in the LCP-EPRTR dataset.

Since the Energy Roadmap 2050 scenarios pertain only to the EU-27 (without Croatia) and do not have the 200 MWe capacity threshold used in this study, an adjustment has been made to the Roadmap scenarios ([11]).

Figure 1.1 shows the exclusion process performed. First, only fossil fuel units were considered. These constitute 51 % of operational and planned capacity across the EU. Second, the focus was placed on only gas, coal and oil based capacity of 200 MWe or greater, constituting 66 %, 75 % and 43 % of each fuel stock at EU level, respectively. This selection results in 411 GWe of total expected EU-wide fossil fuel capacity, representing 34 % of all EU-wide operational and planned power plant capacity (1.2 TWe), and 68 % of all EU-wide operational and planned fossil fuel capacity. Of this 411 GWe of capacity, 70 % of capacity is currently operational (289 GWe), with the remaining 30 % capacity at either the planning or construction phase ([12]).

As smaller units were not covered by this assessment, it means that there is a certain gap when comparing the bottom-up assessment and its underpinning database with the cost-effective EU decarbonisation scenarios from the Energy Roadmap 2050. Smaller units are expected to be used to cover peak loads and, as such, to contribute less to energy generation and GHG emissions. The 2012 ETS emissions linked to the bottom-up database (in the baseline year — 2014) account for 92 % of the carbon dioxide emissions expected from fossil fuel-based electricity generation in the Roadmap scenarios (for the year 2015). In order to adjust the top-down scenarios and make them comparable with the bottom-up database, it was assumed that around 10 % of expected thermal generation and emissions would be covered by smaller units. Therefore, the bottom-up database in this assessment is equivalent to only 90 % of the projected energy generation for the different scenarios ([13]).

Figure 1.1 Representation of capacity assessed under this study, versus all EU power capacity



Source: EEA (based on Platts, 2014 for EU-28 power capacity, including OPR, PLN, DEL, DAC, CON) (see also footnotes 8 and 9).

([11]) It is important to note that the Energy Roadmap 2050 scenarios provide information only for the EU-27 (not including Croatia), while the bottom-up assessment results shown in Chapter 2 pertain to the EU-28. Nevertheless, Croatia's contribution is minimal (0.2 % of operational installed capacity of 200 MWe and above in 2014, according to the present assessment).

([12]) Deactivated/mothballed units (DAC) were included in the operational capacity, since they are considered to be temporarily closed.

([13]) This should be after the exclusion of Croatia. However, given that Croatia had only 950 MWe installed operational capacity in 2014 in the database underpinning the bottom-up assessment, and that these plants reported no emissions (under ETS 2012), no additional steps were taken.

Box 1.5 Considerations regarding new projects in the Platts (2014) database

The database includes information on new projects. The status codes for new projects are CON = under construction (physical site construction is under way), PLN = planned (still in planning or design), and DEL = delayed (construction started but later halted). However, the Platts database is not a forecasting tool. Key determinants in approximate order of importance are: (1) order placement for generating equipment or engineering, procurement and construction (EPC) services, (2) the status of licensing or permitting activities, (3) funding, and (4) the availability of fuel or transmission access. Projects may also be included even if such data are lacking if there are generalised national or regional policies that are driving power plant development.

Most information available for new projects is for the five years after the release date. Due to scheduling, data for the near-term (2–3 years) are more reliable than data for plants expected to come online in later years. In this assessment and its underpinning database, all fossil fuel capacity that is under construction (CON) and 57 % of the planned fossil fuel capacity (PLN) were expected to be operational by 2020.

Another factor to consider is facility size and technology. Larger projects have longer lead times, and large thermal, nuclear and hydroelectric plants have longer lead times than plants using technologies allowing for a more modular fabrication and assembly, such as smaller gas and steam turbines and internal combustion engines. This allows for somewhat more accurate, medium-term enumeration of expected service dates for larger, more complex projects, as opposed to small thermal, hydro or renewable plants.

It is also important to take into account the fact that the deterioration in the profitability of gas plants under current market conditions is likely to have an impact on the PLN intentions captured by the Platts database.

Geographical scope

The assessment results are first and foremost relevant at the EU level. For a more detailed overview, the results were also grouped according to the following four generic clusters: central-western Europe (CWE), central-eastern Europe (CEE), northern Europe and the Baltics (NEB) and south and south-eastern Europe (SSEE). This generic aggregation, proposed on the basis of the European Commission's *Quarterly report on European electricity markets* (EC, 2016), is preferred for an easy comparison of results ([14]).

Time horizon

The analysis focuses on the short and medium term (2020–2030). On the one hand, the bottom-up lifetime investigation used is suited to short and medium timespans because much of the assessed capacity already exists. On the other hand, the 2020–2030 timeframe best illustrates the significant consequences of the decisions that operators and investors will take within the next 5–10 years.

Static approach

The study focuses only on fossil fuel-fired units in the power sector and key considerations about their implications under the chosen set of lifetime conditions. It does not model the evolution of the sector in a dynamic, market-driven manner, and it does not assess the need for new capacity additions or the effect of changes in load hours, due to the uncertainties and complexities of representing these conditions and their impacts on the power sector econometrically ([15]). In reality, a greater number of factors than those assessed within this study influence the lifetime of individual fossil fuel capacity. Such factors go beyond expectations regarding the evolution of international fossil fuel prices and macro-economic conditions. They also include, for example, electricity market conditions (including the specific impacts of national capacity mechanisms, where they exist), the building of cross-border interconnections and carbon dioxide prices under the EU ETS.

([14]) Grouping according to current wholesale electricity markets would lead to seven, rather fragmented, regions, with, for instance, Greece and Italy each being a region on its own.

([15]) All other forms of power generation were taken into account in using the Energy Roadmap scenarios. However, these forms of electricity generation were not included in the bottom-up assessment or in the database-linking exercise.

Dimensions that were excluded from the assessment were:

- the electricity market (including pricing and the effect of national policies);
- econometric or market-based modelling;
- new investments that are not included in the Platts database;
- the effects of the decreasing EU ETS cap and of carbon prices under the ETS;
- interconnections and the potential for cross-border trade in electricity;
- demand-side management and storage options, other than those already considered by the European Commission in the Energy Roadmap 2050 scenarios.

Ownership profile

The aggregation of capacity by multinational power companies and holdings was carried out using the information available in the Platts database (2014 edition). The database does not provide exhaustive or definitive parent company data and does not track joint ownership shares. Owing to market dynamics, some companies and units names in the database may have changed since 2014. Therefore, the aggregation of capacity by companies and fuel, in Chapter 2, is only indicative.

1.3.3 Lifetime assumptions

Lifetime assumptions are a determining factor for the bottom-up calculation of the illustrative power sector profiles constructed for this study. The choice of these assumptions was the object of a specific investigation that looked at the expected lifetimes of operational power plants, using information from the PPT database (Enerdata, 2015), and at the lifetime of the already retired units based on information from the WEPP database (Platts, 2014). The results were cross-checked with information obtained from the literature.

The assessment led to the formulation of the **average** (AVG profile) and **extended** (EXT profile) lifetime values shown in Table 1.1.

Nevertheless, implementing the average lifetime values in the AVG profile has resulted in one third of all operational fossil fuel capacity being decommissioned already by 2015. The extended lifetime values therefore appear to be more appropriate to reflect current developments in the sector.

The extended lifetime values were thus implemented in the REV (revised) profile, which takes into account potential technological upgrades to comply with the IED. To represent the technological upgrades in the REV profile, a 20-year lifetime extension was applied to that capacity for which a technological upgrade to comply with the IED was assumed to have taken place. In accordance with the current legislation, the REV profile thus assumes that plants that have opted out under the LCP Directive and plants operated

Table 1.1 Lifetime assumptions implemented in the bottom-up profiles

Capacity by fuel type / Lifetime assumptions	**Average** (used in AVG profile)	**Extended** (used in EXT and REV ([a]) profiles)
Coal	40 years	50 years
Gas	35 years	45 years
Oil	40 years	50 years

Note: ([a]) In the REV profile, a 20-year lifetime starting with 2023 was implemented for that capacity for which a technical upgrade to comply with the IED was assumed to take place.

under the limited lifetime derogation (IED, Article 33) will be closed before 2025 (i.e. by end 2015 and by 2023, respectively). Moreover, plants that are part of a transitional national plan (IED, Article 32), and other plants, are expected to operate until the end of their lifetimes, or to undergo a technological retrofit in 2023 (+ 20 years) to meet the stricter ELVs under the IED. The EEA used a series of air pollution parameters and plant emissions data to initially classify plants (and their corresponding units) into 'potential candidates for investment' and 'potential candidates for closure', respectively. This initial classification was sent to 22 EU Member States concerned by the scope of the assessment, as part of an Eionet consultation ([16]). Revised responses were received from 15 countries, while seven Member States either did not respond, or indicated that they did not have this information (Austria, Bulgaria, Finland, France, Germany, Spain and the United Kingdom).

1.4 Report structure

This report is structured in the following way: Chapter 1 provides an introduction to the study; Chapter 2 presents the current profile of the fossil fuel power sector, obtained from the bottom-up analysis, along with an initial set of comparisons with the Energy Roadmap scenarios for 2015; Chapter 3 presents a forward-looking analysis of the current fossil fuel power sector, considering technical decommissioning pathways and the potential requirement for upgrading to meet air emission standards; Chapter 4 compares the findings of the bottom-up assessment with the levels within the Energy Roadmap 2050 scenarios, explores the potential risks of carbon lock-in or stranded assets and presents the conclusions from the comparisons. In addition, Annex 1 presents several sensitivity analyses performed as part of this study.

([16]) The European Environment Information and Observation Network (Eionet) is a network of environmental bodies and institutions that is active in the EEA member countries.

2 Current sectoral profile

This chapter aims to provide an overview of the current fossil fuel power sector, based on a unit-level analysis (bottom-up assessment) of the total expected capacity. Hypothetical future pathways for capacity lifetime are then discussed in Chapter 3, while Chapter 4 discusses the need for a different evolution of the sector in order to increase coherence with the anticipated EU decarbonisation agenda in the short and medium term.

The analysis highlights Europe's considerable reliance on its conventional energy capacity. Conventional power capacity (including gas, coal and oil) accounted for 53 % of the overall expected capacity in the EU in 2014 (or 65 % when considering only those units of 200 MWe and above). At the EU level, coal-fired capacity represents 47 % and gas-fired capacity 44 %, respectively, in proportion to the 2014 installed EU-wide fossil fuel capacity of 308 GWe (see Box ES.1). Together, these two fuel sources are responsible for almost all the fossil fuel power capacity in the bottom-up analysis ([17]).

There are regional variations between these fuels, although they always comprise at least 80 % of the share of the total capacity in the database when taken together at the regional level. The region where a power plant is located has a significant bearing on both the plant's status and its age. In turn, this has important consequences for the calculated power profile in terms of expected decommissioning trends and carbon intensity.

When the scenario information from the Energy Roadmap 2050 (for the year 2015) is compared with the data for the baseline year (2014) suggested by the bottom-up analysis, the installed capacities are fairly consistent (after making the adjustments necessary to account for smaller power plants). Additional information on the comparison is presented in Chapter 4.

2.1 EU profile

The figures below summarise the status, age and fossil fuel profile of the total expected capacity at the EU level, considering the currently available information (Platts, 2014). For the assessment (except in the regional fuel profile, in which nuclear units were also included to give a more complete picture of the energy mix), only selected units of 200 MWe and over were covered, as described in Section 1.3.3.

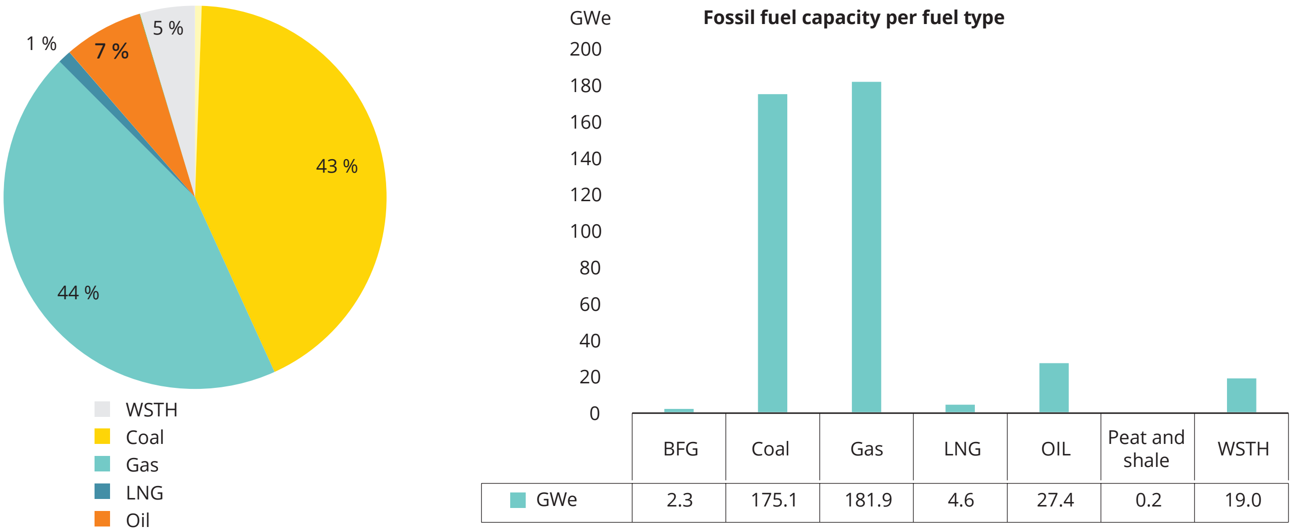
Taking the capacity of the current units in the bottom-up assessment, the majority is either operational (70 %) or planned (21 %). The remainder is under construction (4 %), deactivated (4 %), or delayed (< 1 %). Operational units, according to the Platts database, have a total electricity-generating capacity of 288 GWe. In the following chapters these capacities have been slightly adjusted to take into account deactivated units and other units (e.g. under construction or delayed) that were expected to be commissioned before 2015).

Historically, the decade with the highest rates of construction in terms of fossil fuel capacity was 2000–2009, with 73 GWe (18 %) of capacity being installed over that period. Up to 1980 (starting at 1963 in the database), 101 GWe (25 %) of the total fossil fuel capacity was installed. In the period 1980–1989, significantly less capacity was installed, totalling only around 50 GWe (12 %) of capacity. The following decade (1990–1999) saw a decline in construction of new capacity to 34 GWe (8 %). Since then, over the period 2010–2015, a further 64 GWe (16 %) of capacity has been constructed. The remaining 88.3 GWe (21 %) of power capacity will be constructed post 2015 ([18]).

At the EU level, the fossil fuel units assessed relied predominantly on gas and coal (44 % and 43 %, respectively, of the total expected fossil fuel capacity in the bottom-up analysis). The remainder was

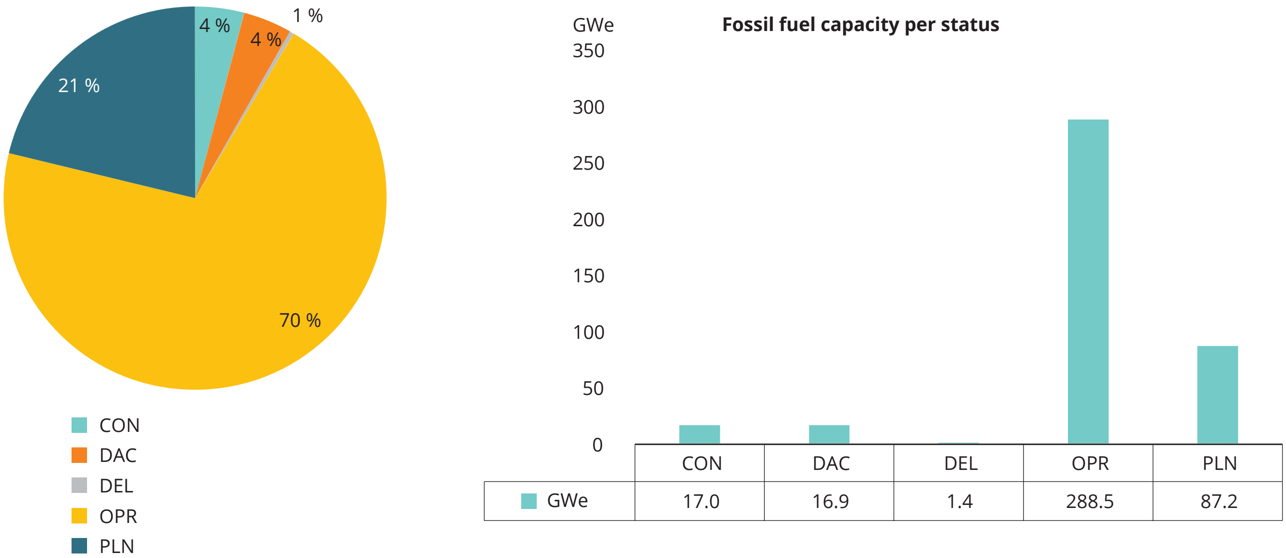
([17]) At the EU level, in proportion to the total expected capacity of 411 GWe, gas accounts for the highest capacity as a fuel (44 %), with coal not far behind (43 %).
([18]) Please note that this comparison focuses on active units, and units/plants that were permanently closed were not included in this assessment.

Figure 2.1 Total expected capacity by fuel type, status and age, EU-28 (fossil fuel units ≥ 200 MWe, excluding nuclear power)



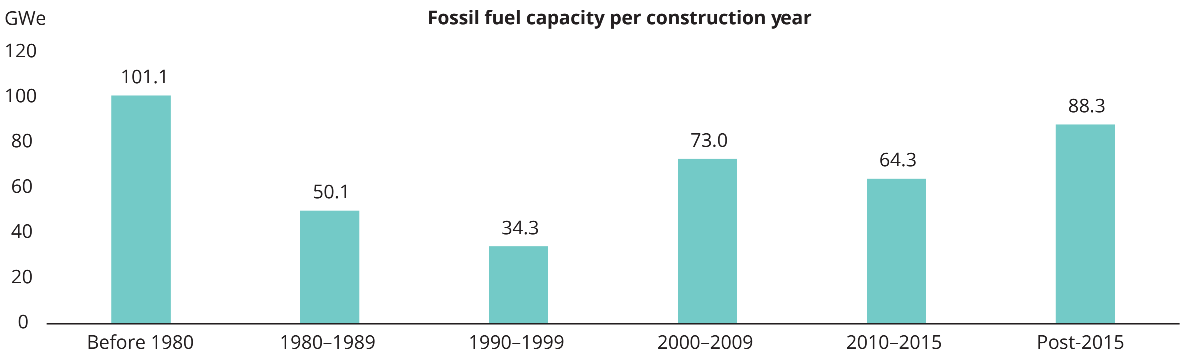
	BFG	Coal	Gas	LNG	OIL	Peat and shale	WSTH
GWe	2.3	175.1	181.9	4.6	27.4	0.2	19.0

Note: BFG, blast furnace gas; LNG, liquefied natural gas; WSTH, waste heat.



	CON	DAC	DEL	OPR	PLN
GWe	17.0	16.9	1.4	288.5	87.2

Note: CON, under construction; DAC, deactivated, mothballed; DEL, delayed; OPR, operational; PLN, planned. Excluding nuclear plants.



Source: EEA (based on Platts, 2014).

provided by oil (7 %), waste heat (5 %), liquefied natural gas (LNG), blast furnace gases, oil shale and peat (each ≤ 1 %).

2.2 Regional profiles

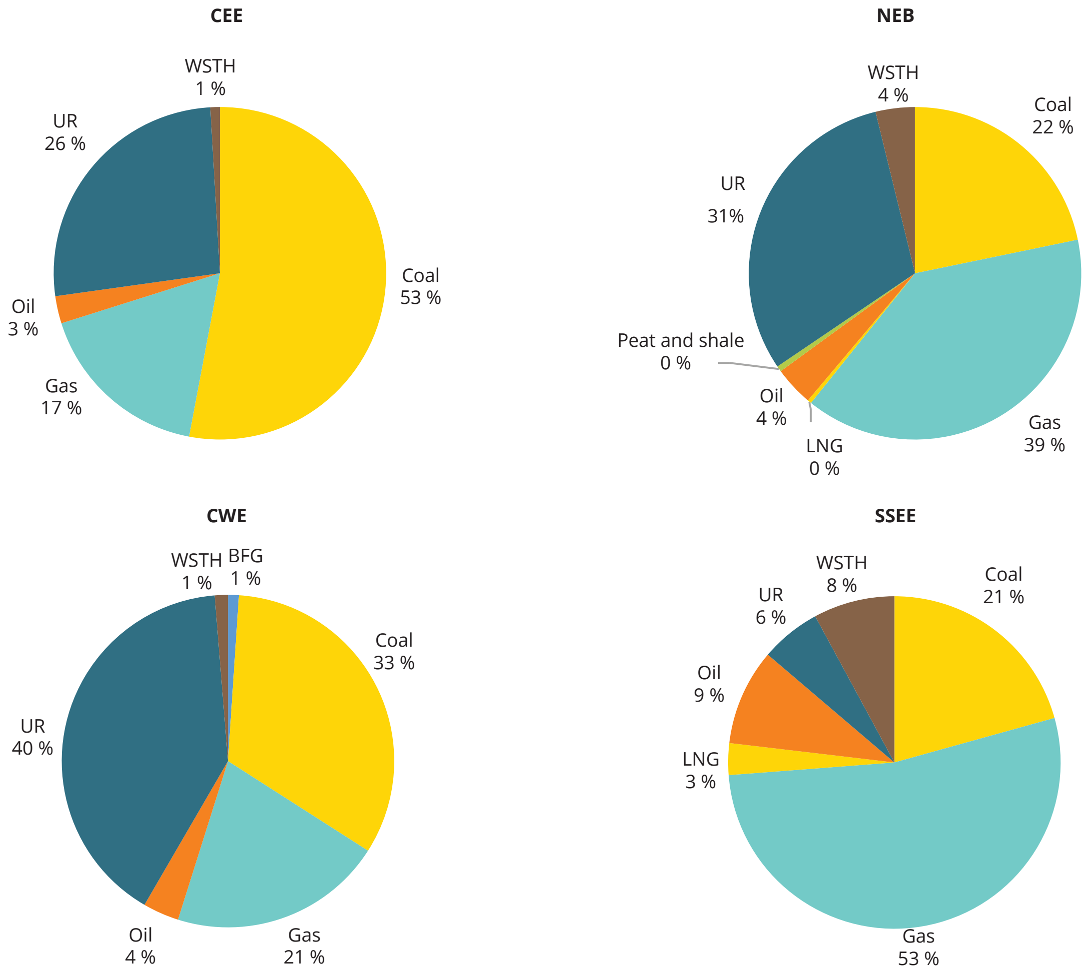
This section shows how the selected EU regions differ in terms of the overall importance of fossil fuels in the regional fuel profiles and in terms of the status and age of their fossil fuel capacities. The sectoral representation in this section includes uranium as a fuel source (albeit not fossil fuel driven) in order to give a clearer indication of the thermal capacity in each of these regions and as this is relevant from the perspective of decarbonisation and transformation of the energy sector.

2.2.1 Regional fuel profiles

The figures below present an overview of the status of the thermal power sector, by fuel type, for each of the four regions under assessment. The assessment demonstrates that there are clear regional differences in fuel usage, linked, for example, to historic resource availability, geopolitical aspects, and past and present support for certain fuels (EEA, 2014b, 2014c). Overall, CEE has predominantly coal-fired units, while CWE has a large amount of nuclear power. SSEE and NEB have mostly gas-fired units.

As shown in Figure 2.2, overall, gas is the fuel most heavily relied on in the EU. SSEE is the region with the highest proportion and greatest absolute gas-fired capacity, totalling 70 GWe (53 % of capacity). Coal is the

Figure 2.2 Total expected regional capacity profile, by fuel type, EU-28 (fossil fuel units ≥ 200 MWe and nuclear power)



Note: BFG, blast furnace gas; LNG, liquefied natural gas; UR, uranium; WSTH, waste heat.

Source: EEA (based on Platts, 2014).

second-most frequently used fuel among the countries in the database, with the CEE region relying on coal for 53 % of its capacity (47.6 GWe). Although this may be the highest share by region, the greatest absolute use of coal is in CWE, at 71.6 GWe. The use of uranium as a fuel source varies considerably among the regions: in CWE it accounts for 40 % of power plant unit capacity (87.5 GWe), but in the SSEE region it accounts for only 6 % (7.7 GWe).

2.2.2 Regional status profiles

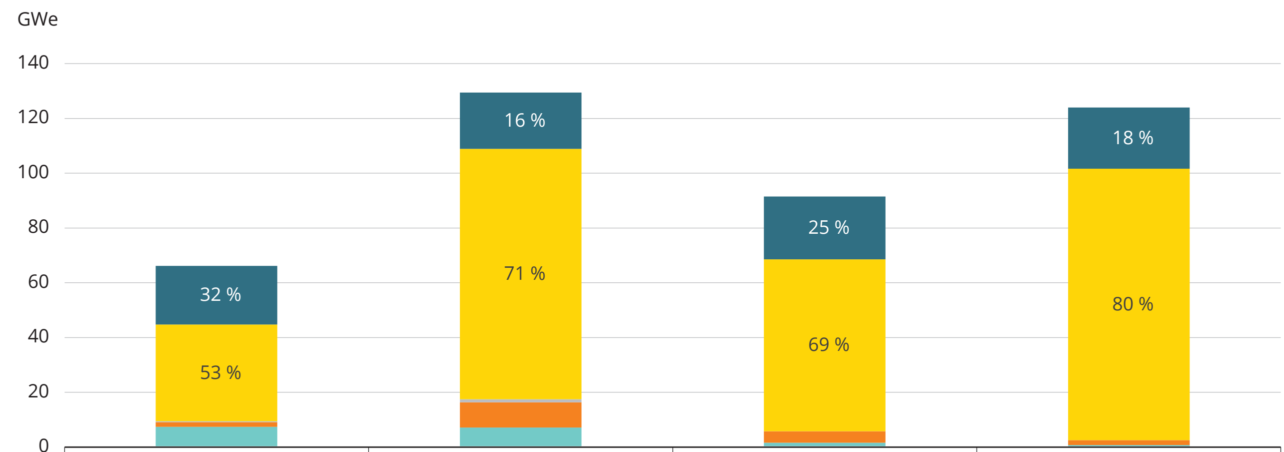
With regard to the status of the fossil fuel units assessed, in all regions the majority of these units are operational. However, for all regions there is a significant amount of planned fossil fuel capacity, ranging from 20.5 to 23 GWe per region (representing 21 % of the total expected fossil fuel capacity according to the scope of this report, respectively 10 % of all of today's operational power capacity ([19])).

The highest proportion of operational fossil fuel units is to be found in CWE (91.4 GWe) and SSEE (99.1 GWe), with 22 % and 24 % of total EU capacity, respectively, according to the scope of the study (or between 10 % and 11 % of all of today's operational power capacity). Only around 4 % of all units are deactivated, with little variation among the regions. The recent trend towards, and discussions regarding the mothballing of gas plants, since two years ago, may not yet be reflected in the Platts database ([20]).

2.2.3 Regional age profiles

The assessment of the age profile of the fossil fuel power plant units illustrates that there is considerable variability among regions with respect to their capacity by construction year. As such, one quarter of the fossil fuel capacity under assessment was already in place by 1980, with installed capacities ranging between 16.1 GWe, in SSEE, and 37.5 GWe, in CWE. On the other hand, about one fifth of all the units assessed is still expected to be constructed. CEE had almost no fossil fuel capacity constructed between 1990 and 2009 (3.8 GWe). The period 1990–1999 was, altogether, one of low capacity construction, with installed capacities ranging between 2.4 GWe, in CWE, and 11.5 GWe, in the NEB region. In contrast, the period 2000–2009 was

Figure 2.3 Total expected regional capacity profile by status (fossil fuel units ≥ 200 MWe)



	CEE	CWE	NEB	SSEE
PLN	21.4	20.5	23	22.3
OPR	35.3	91.4	62.7	99.1
DEL	0.3	1.1	0	0
DAC	1.7	9.3	4.2	1.7
CON	7.4	7.1	1.7	0.8

Note: CON, under construction; DAC, deactivated, mothballed; DEL, delayed; OPR, operational; PLN, planned.

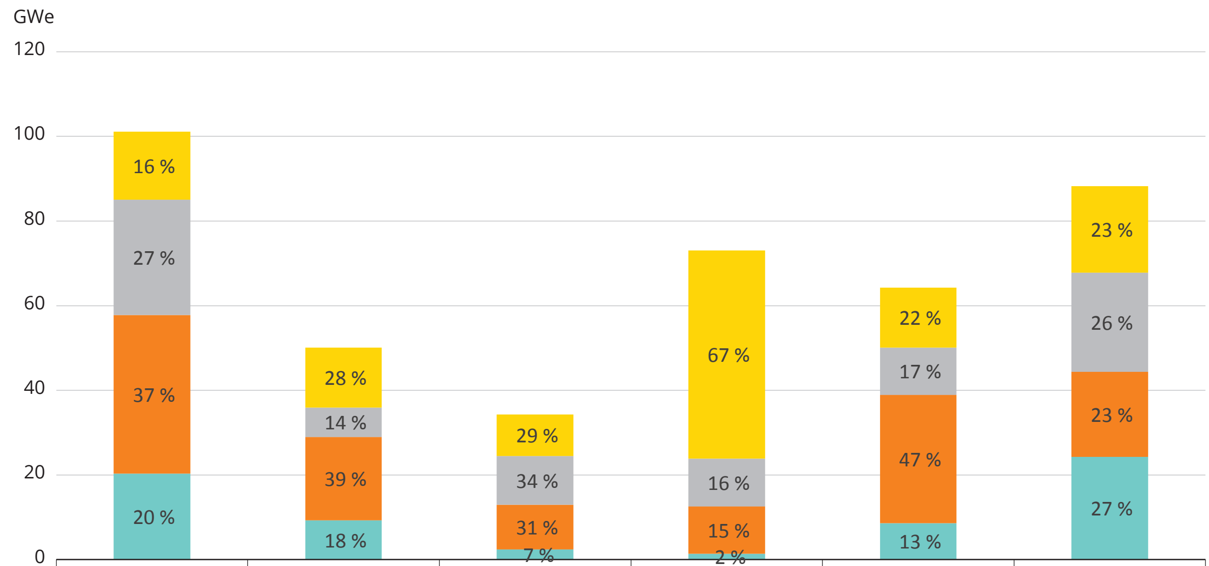
Source: EEA (based on Platts, 2014).

([19]) Including units with capacities under the 200 MWe threshold, and including renewable and nuclear energy capacities.
([20]) In this regard, the Platts WEPP 2014 commercial database includes only four units (built after 2000) as being mothballed, with a total capacity of 1.5 GWe.

the most productive in terms of fossil fuel capacity construction, due in particular to expansions that took place in SSEE (18 % of the fossil fuel capacity under assessment was constructed during this decade). The same period, however, was among the least productive for the other regions. Figure 2.4 shows the operational fossil fuel units, of 200 MWe and above, by their year of construction.

There was a peak in nuclear energy capacity construction during the 1980s in CWE, where 63 GWe were put into operation, although this is not reflected in Figure 2.4.

Figure 2.4 Total expected regional capacity profile by year of construction (fossil fuel units ≥ 200 MWe)



	Before 1980	1980–1989	1990–1999	2000–2009	2010–2015	Post–2015
SSEE	16.1	14.2	9.9	49.2	14.2	20.5
NEB	27.2	6.9	11.5	11.3	11.1	23.4
CWE	37.5	19.7	10.5	11.2	30.4	20.1
CEE	20.3	9.3	2.4	1.4	8.6	24.3

Source: EEA (based on Platts, 2014).

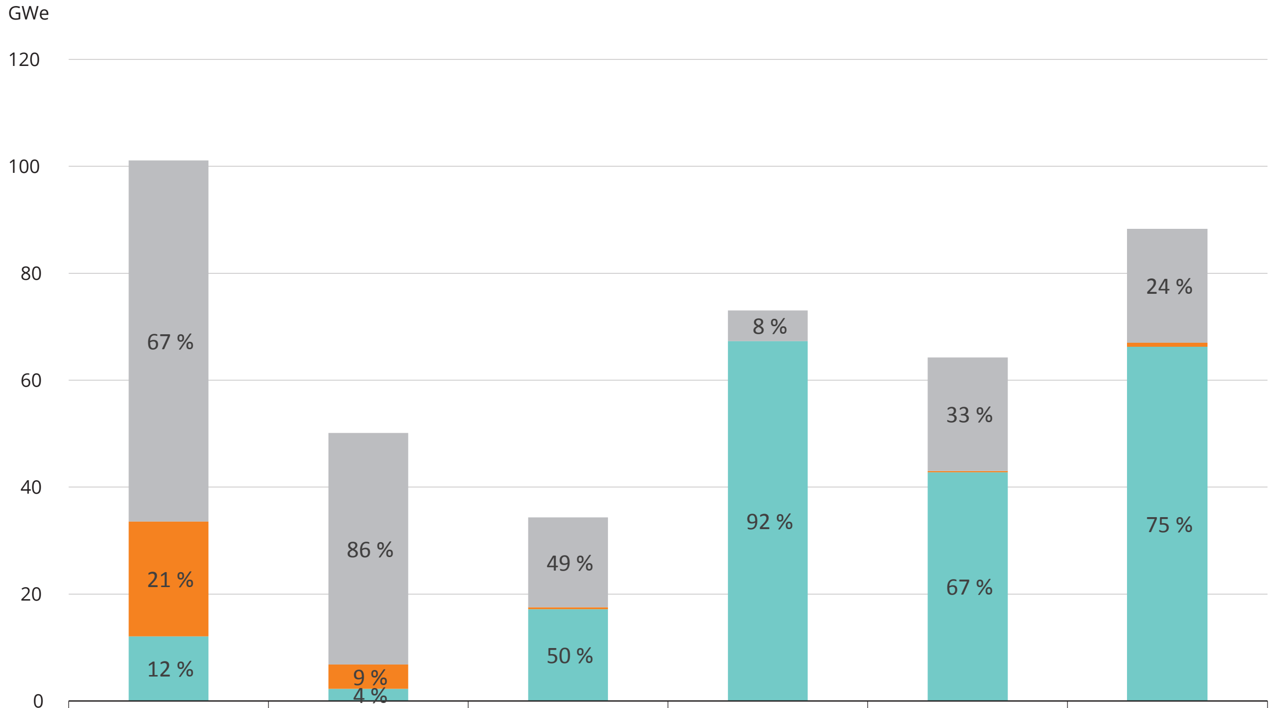
Table 2.1 Total expected regional capacity profile by fuel type

Region and fuel type	Before 1980	1980–1989	1990–1999	2000–2009	2010–2015	Post-2015	Total
CEE	20 GWe (31 %)	9 GWe (14 %)	2 GWe (4 %)	1 GWe (2 %)	9 GWe (13 %)	24 GWe (37 %)	66 GWe (100 %)
Gas	1 GWe (8 %)	0 GWe (0 %)	0 GWe (0 %)	0 GWe (0 %)	4 GWe (25 %)	11 GWe (67 %)	16 GWe (100 %)
Oil	2 GWe (90 %)	0 GWe (0 %)	0 GWe (0 %)	0 GWe (0 %)	0 GWe (10 %)	0 GWe (0 %)	2 GWe (100 %)
Solid fuel	17 GWe (35 %)	9 GWe (19 %)	2 GWe (5 %)	1 GWe (3 %)	4 GWe (9 %)	13 GWe (28 %)	48 GWe (100 %)
CWE	38 GWe (29 %)	20 GWe (15 %)	11 GWe (8 %)	11 GWe (9 %)	30 GWe (23 %)	20 GWe (16 %)	129 GWe (100 %)
Gas	8 GWe (16 %)	0 GWe (1 %)	3 GWe (6 %)	8 GWe (17 %)	15 GWe (30 %)	15 GWe (31 %)	50 GWe (100 %)
Oil	7 GWe (95 %)	0 GWe (0 %)	0 GWe (5 %)	0 GWe (0 %)	0 GWe (0 %)	0 GWe (0 %)	8 GWe (100 %)
Solid fuel	22 GWe (31 %)	19 GWe (27 %)	7 GWe (10 %)	3 GWe (4 %)	15 GWe (21 %)	5 GWe (7 %)	72 GWe (100 %)
NEB	27 GWe (30 %)	7 GWe (8 %)	12 GWe (13 %)	11 GWe (12 %)	11 GWe (12 %)	23 GWe (26 %)	92 GWe (100 %)
Gas	2 GWe (3 %)	1 GWe (2 %)	10 GWe (17 %)	11 GWe (20 %)	11 GWe (19 %)	23 GWe (40 %)	57 GWe (100 %)
Oil	4 GWe (87 %)	1 GWe (13 %)	0 GWe (0 %)	0 GWe (0 %)	0 GWe (0 %)	0 GWe (0 %)	5 GWe (100 %)
Solid fuel	21 GWe (71 %)	5 GWe (18 %)	2 GWe (7 %)	0 GWe (1 %)	1 GWe (2 %)	0 GWe (2 %)	29 GWe (100 %)
SSEE	16 GWe (13 %)	14 GWe (11 %)	10 GWe (8 %)	49 GWe (40 %)	14 GWe (11 %)	20 GWe (17 %)	124 GWe (100 %)
Gas	1 GWe (1 %)	1 GWe (1 %)	5 GWe (6 %)	48 GWe (57 %)	13 GWe (15 %)	17 GWe (20 %)	84 GWe (100 %)
Oil	8 GWe (62 %)	4 GWe (32 %)	0 GWe (0 %)	0 GWe (0 %)	0 GWe (0 %)	1 GWe (6 %)	12 GWe (100 %)
Solid fuel	8 GWe (28 %)	9 GWe (34 %)	5 GWe (19 %)	1 GWe (5 %)	1 GWe (5 %)	3 GWe (10 %)	27 GWe (100 %)
EU-28	101 GWe (25 %)	50 GWe (12 %)	34 GWe (8 %)	73 GWe (18 %)	64 GWe (16 %)	88 GWe (21 %)	411 GWe (100 %)

Note: Includes all installed and expected new units ≥ 200 MWe (all statuses).

Source: EEA (based on Platts, 2014).

Figure 2.5 Total expected capacity by year of construction and fossil fuel type (fossil fuel units ≥ 200 MWe)



	Before 1980	1980–1989	1990–1999	2000–2009	2010–2015	Post–2015
Solid	68	43	17	6	21	21
Oil	21	5	0	0	0	1
Gas	12	2	17	67	43	66

Source: EEA (based on Platts, 2014).

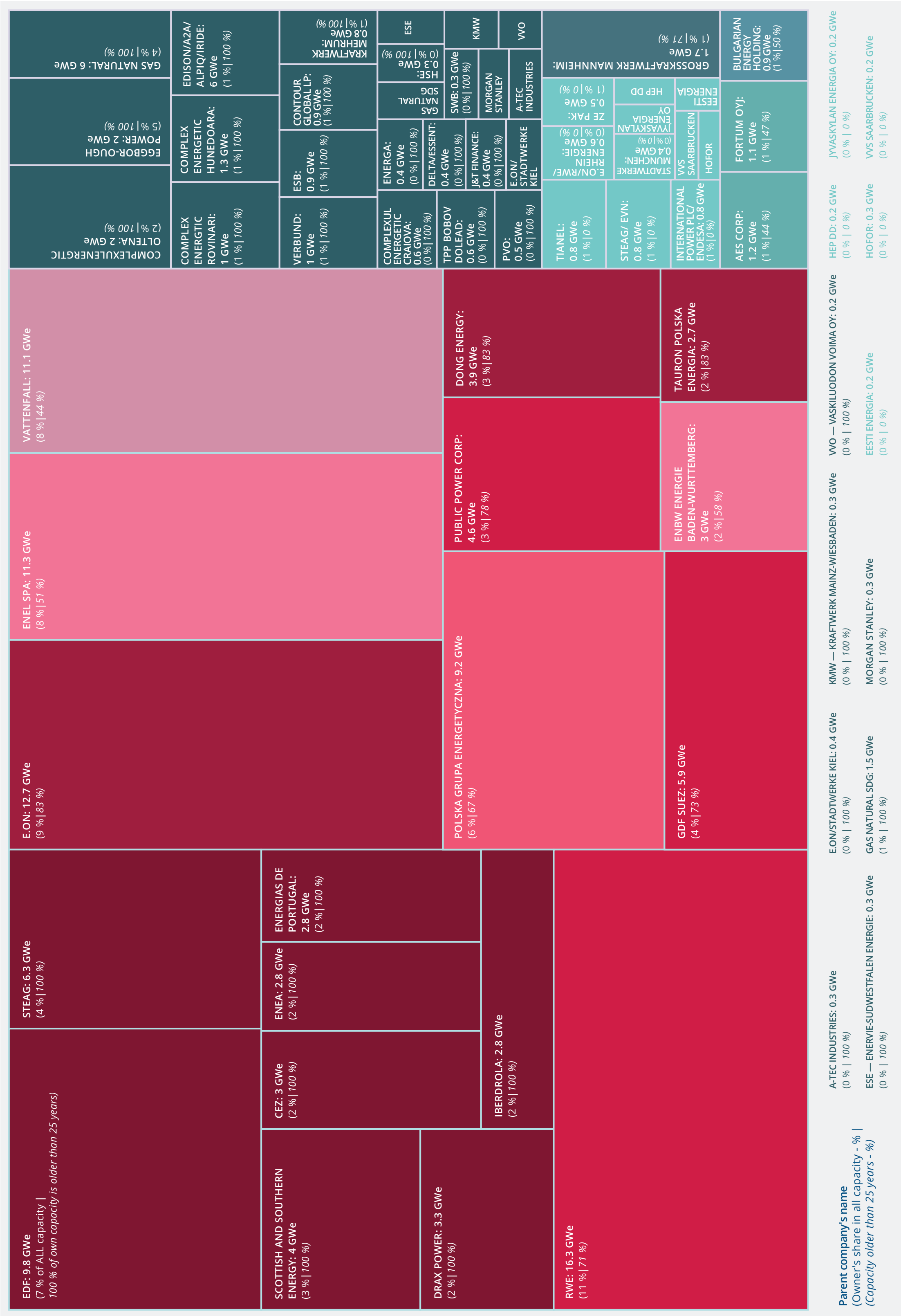
2.3 Ownership profiles

Overall, large fossil fuel units tend to be owned and operated by large, private or state-owned power companies. Some fossil power stations (especially large coal plants) are jointly-owned and owners may include a mix of power companies and other parties, such as fuel or manufacturing companies, investment funds and financial institutions, and national or local government authorities of various kinds.

In 2014, aggregated by parent and for all fossil fuel capacity, 23 companies owned 71 % of the total expected fossil fuel capacity, while 121 companies owned the remaining 29 % ([21]). Compared with this, the concentration of ownership was slightly higher when it was aggregated by parent for installed solid fuel-based capacity only, as illustrated in Figure 2.6: 18 enterprises owned 80 % of all the installed solid fuel-fired capacity, and over two thirds of this capacity was already over 25 years old.

([21]) The parent company designation is generally the ultimate parent, not the immediate parent. Where no parent is identified, the company name is given (Platts).

Figure 2.6 Existing solid fuel-fired capacity by parent company (status: end 2014)



Note: Red: 18 parent companies own 80 % of all existing solid fuel-fired capacity. Dark blue: 40 parent companies own the remaining 20 % of all operational and deactivated/mothballed solid fuel-fired capacity. Dark shades indicate a high prevalence of solid fuel-fired capacity > 25 years old (for both colours); light shades indicate a higher proportion of younger units.

Source: EEA (based on Platts, 2014).

2.4 Comparison of current sectoral profiles with the Energy Roadmap levels

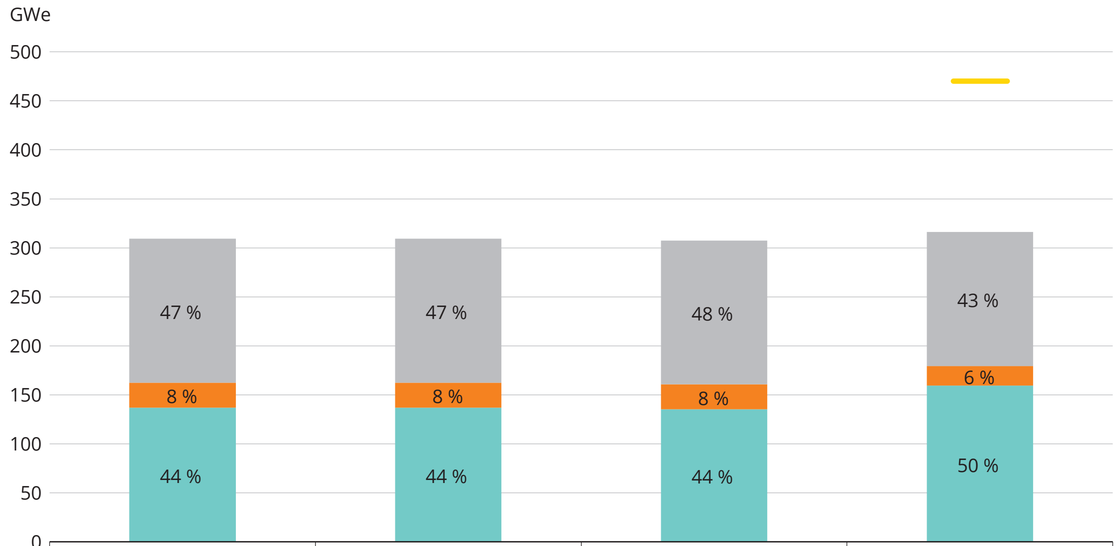
The European Commission published its Energy Roadmap 2050 assessment in 2011 (EC, 2011c). To understand the potential initial differences between the selected Roadmap scenarios and the current sectoral profiles obtained during this study, we compared the Roadmap scenario data for 2015 with the current sectoral power profiles obtained in a bottom-up fashion.

As the three Roadmap scenarios are almost identical for 2015 (due to their proximity to the baseline year), they are averaged into a single (scope-adjusted) Roadmap scenario. This section summarises the results of that comparison.

2.4.1 Comparison based on installed capacity

After performing the scope adjustment, the installed capacities in the baseline year were consistent between the top-down (Roadmap) scenarios and the bottom-up profiles (Figure 2.7), particularly for the NEB region and CWE (Figure 2.8). SSEE and CEE, on the other hand, presented slight differences. For SSEE, the top-down scenario seemed to have been exceeded by 2014 by roughly 10 GWe (after adjustment), according to the bottom-up profile, as the region installed more gas and solid fuel-fired capacity between 2010 and 2014 and decommissioned less oil-based capacity than projected in the Roadmap. For CEE, the top-down scenario accounted for an additional 13 GWe (after adjustment), mostly solid fuel-fired capacity, compared with the bottom-up profile, as less new coal-fired capacity was constructed in practice than was projected in the Roadmap.

Figure 2.7 Comparison of currently installed EU-27 capacity profiles, 2014/2015, by fuel type (GWe)

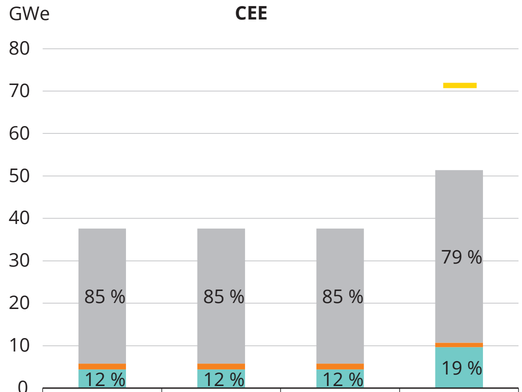


	EXT	AVG	REV	Top-down adjusted
Solid	147	147	146	137
Oil	26	26	26	20
Gas	137	137	135	159
Non-adjusted top-down	N/A	N/A	N/A	470

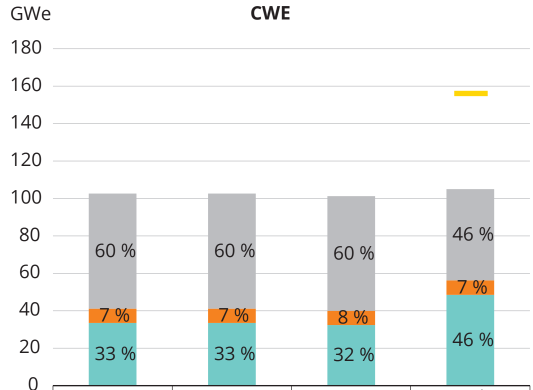
Note: Bottom-up results shown for 2014; Energy Roadmap averages shown for 2015.
EXT, bottom-up profile considering extended lifetimes.
AVG, bottom-up profile considering no lifetime extension.
REV, bottom-up profile considering potential upgrades/closures to comply with the requirements to reduce air pollutant emissions (including consultation results).
Top-down adjusted: average of the three selected Energy Roadmap 2050 scenarios adjusted to account for the 200 MWe capacity threshold.

Source: EEA (based on Platts, 2014; and EC, 2011c).

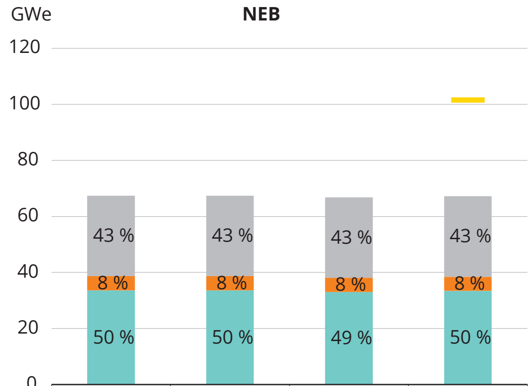
Figure 2.8 Comparison of currently installed regional capacity profiles, 2014/2015, by fuel type (GWe)



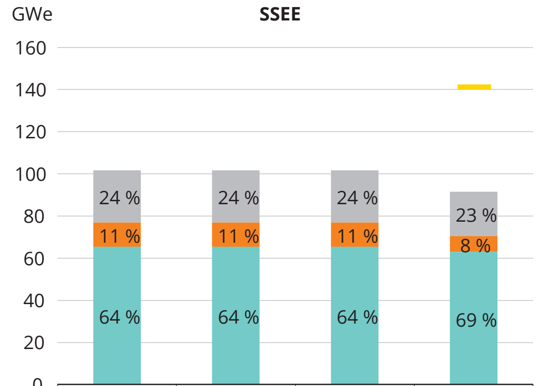
	EXT	AVG	REV	Top-down adjusted
Solid	32	32	32	41
Oil	1	1	1	1
Gas	4	4	4	10
Non-adjusted top-down	N/A	N/A	N/A	71



	EXT	AVG	REV	Top-down adjusted
Solid	62	62	61	49
Oil	8	8	8	8
Gas	33	33	32	48
Non-adjusted top-down	N/A	N/A	N/A	157



	EXT	AVG	REV	Top-down adjusted
Solid	29	29	29	29
Oil	5	5	5	5
Gas	34	34	33	33
Non-adjusted top-down	N/A	N/A	N/A	101



	EXT	AVG	REV	Top-down adjusted
Solid	25	25	25	21
Oil	12	12	12	8
Gas	65	65	65	63
Non-adjusted top-down	N/A	N/A	N/A	141

Note: Bottom-up results shown for 2014, for EU-27; top-down (adjusted) results shown for 2015, adapted to account for the 200 MWe capacity threshold.

Source: EEA (based on Platts, 2014; and EC, 2011c).

Considering that the units assessed cover around 70 % of the Energy Roadmap capacity and that the bottom-up assessment found a total of 307–309 GWe, the top-down and bottom-up assessments are fairly accurate and comparable regarding capacity in 2014/2015 ([22]).

The most notable difference is that the proportion of gas is slightly lower in the pool of units studied, which indicates (among other things) a potential prevalence of small-scale gas-fired units being used in the top-down analyses but left out of the bottom-up analysis conducted for this report. Solid and liquid fuel capacities remain relatively stable across the scenarios. This may indicate a relative similarity in the scopes of the studies, hence indicating a prevalence of larger (≥ 200 MWe) units. The only difference between the extended (EXT) and revised (REV) power sector profiles in 2015 is a slightly lower gas-fired capacity in the REV profile, following Member States' feedback on the EEA's initial findings. A specific comparison among the EXT, AVG and REV profiles is, however, most relevant with regard to the hypothetical short- and medium-term decommissioning trends and is therefore shown in the following chapters.

2.4.2 Comparison based on electricity generation

Figure 2.9 shows electricity production, by fuel type, for the Roadmap scenarios in 2015 and for the bottom-up sectoral profiles in 2014. The power generation in the bottom-up database is based on the ETS reported emissions for 2012, IPCC fuel emission factors and plant efficiency parameters ([23]). As already indicated, the Roadmap scenarios were adjusted in order to represent only those plants with a capacity of 200 MWe and above. Only 90 % of the expected power generation was taken into account ([24]).

Despite the adjustments, the Energy Roadmap scenarios still project 54 % more energy generation than the bottom-up sectoral profiles (Figure 2.9). This can be partially explained by the approach used in the bottom-up assessment, given that energy generation for 2014 was calculated using the ETS reported carbon dioxide emissions for 2012 as a basis. Due to the economic crisis and other factors, the latter might have actually been lower in 2012 than it was in 2014. Furthermore, some plants that could have been generating in 2014 might have reported no or reduced ETS emissions in 2012. In fact, in some cases emissions were very low or non-existent for plant units that were marked as operational in the Platts database. In the bottom-up profiles shown in Chapter 3, this is corrected for 2020 and 2030 using theoretical estimates for these units (see also Annex 1 — Sensitivity analysis).

The lower gas-fired capacity in the bottom-up results is reflected in the lower energy production therein, constituting 30 % of the mix as opposed to 47 % in the Roadmap scenarios. In turn, this increases the relative proportion of solid fuel energy production in the bottom-up sectoral profiles. In all cases, gas-fired units account for a higher proportion of capacity than energy production, indicating on average lower load factors ([25]).

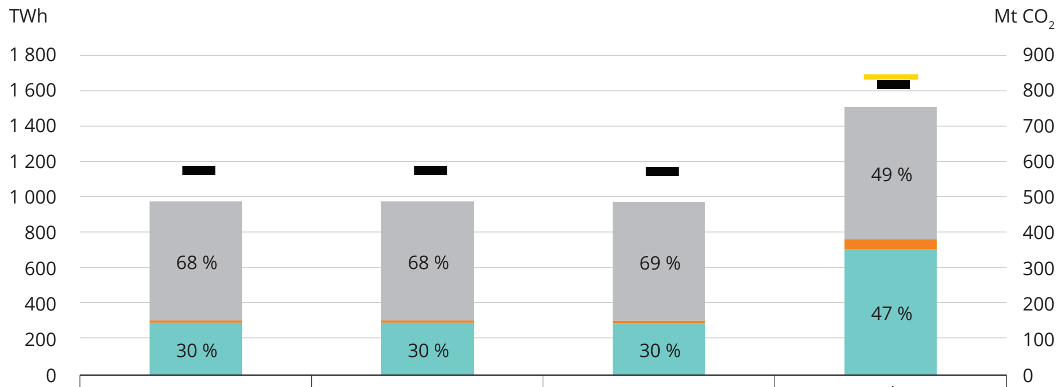
([22]) The scope-adjusted capacity in the Energy Roadmap totals 316 GWe. Croatia is excluded from the bottom-up EU profile to ensure consistency with the Roadmap scenarios. A total capacity of 307 GWe corresponds to the revised decommissioning trends accounting for the potential need for upgrading/decommissioning to meet the IED ELVs, and using Member States' feedback.

([23]) Further information can be found in Annex 1 — Load factor sensitivity — where different methods for calculating electricity generation are presented.

([24]) The ETS emissions linked to the bottom-up analysis account for 92 % of the emissions expected from fossil fuel electricity generation in the Energy Roadmap scenarios. In order to adjust the top-down scenarios and make them comparable with the bottom-up sectoral profiles, it has been assumed that around 10 % of expected thermal generation and emissions will continue being covered by smaller units. Accordingly, the current assessment assumes that the bottom-up sectoral profiles make up only 90 % of the projected energy generation in the three Roadmap scenarios.

([25]) Further information can be found in Annex 1 — Load factor sensitivity — where different methods for calculating electricity generation are presented.

Figure 2.9 Comparison of current EU-27 electricity generation profiles by fuel type (TWh) and carbon dioxide emissions (Mt CO_2), 2014/2015



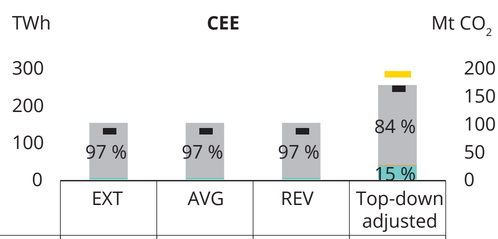
	EXT	AVG	REV	Top-down adjusted
Solid	667	667	666	742
Oil	14	14	14	55
Gas	294	294	291	707
Non-adjusted top-down	N/A	N/A	N/A	1 671
CO_2 (Mt CO_2)	574	574	572	816

Note: Bottom-up results shown for 2014; Energy Roadmap averages shown for 2015.

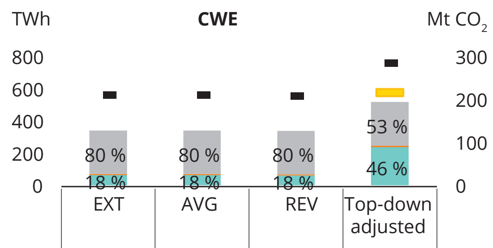
Source: EEA (based on Platts, 2014; and EC, 2011c).

Photo: © Jelena Nedeljković, Environment & Me/EEA

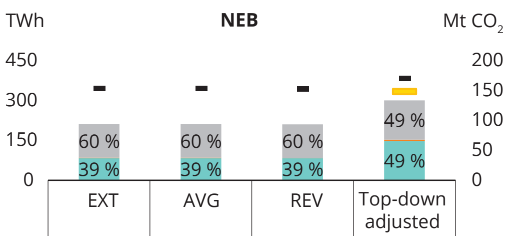
Figure 2.10 Comparison of current regional electricity generation profiles by fuel type (TWh) and carbon dioxide emissions (Mt CO_2), 2014/2015



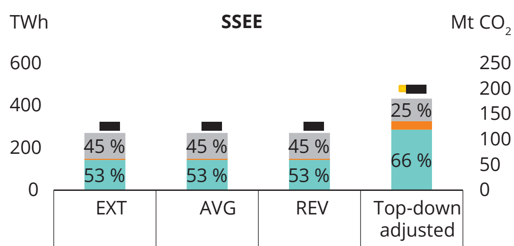
	EXT	AVG	REV	Top-down adjusted
Solid	147	147	147	214
Oil	0	0	0	2
Gas	5	5	5	37
Non-adjusted top-down	N/A	N/A	N/A	282
CO_2 (Mt CO_2)	86	86	86	162



	EXT	AVG	REV	Top-down adjusted
Solid	272	272	271	274
Oil	6	6	6	8
Gas	63	63	61	236
Non-adjusted top-down	N/A	N/A	N/A	575
CO_2 (Mt CO_2)	210	210	208	284



	EXT	AVG	REV	Top-down adjusted
Solid	126	126	126	147
Oil	2	2	2	6
Gas	83	83	82	146
Non-adjusted top-down	N/A	N/A	N/A	332
CO_2 (Mt CO_2)	152	152	152	170



	EXT	AVG	REV	Top-down adjusted
Solid	123	123	123	107
Oil	6	6	6	39
Gas	143	143	143	287
Non-adjusted top-down	N/A	N/A	N/A	482
CO_2 (Mt CO_2)	126	126	126	200

Note: Bottom-up results shown for 2014, for the EU-27; top-down (adjusted) results shown for 2015, adapted to account for the 200 MWe capacity threshold.

Source: EEA (based on Platts, 2014; and EC, 2011c).

2.4.3 Comparison based on carbon dioxide emissions

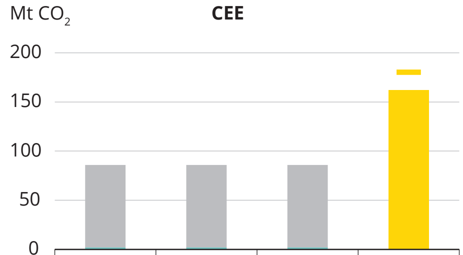
Figure 2.11 compares the estimated carbon dioxide emissions per region, corresponding to the Roadmap scenarios in 2015, with those obtained from the bottom-up sectoral profile (for the year 2014). Given that the top-down scenarios do not provide GHG emissions by fuel type, the figure presents the total emissions corresponding to electricity generation ([26]).

The adjusted Roadmap scenario values account for only 90 % of the total. After taking this into account, carbon dioxide emissions from the (adjusted) Energy Roadmap 2050 scenarios are around 43 % higher than in the bottom-up assessment, which is in line with the expected energy generation.

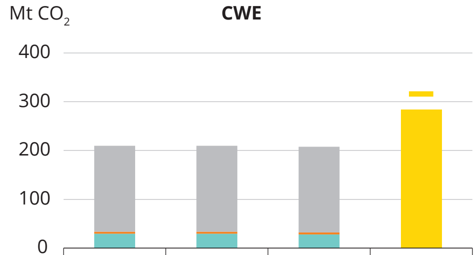
Once more, the revised decommission dates have very little bearing on energy generation and carbon dioxide emissions for 2015, owing to the short time frame.

([26]) As the carbon dioxide emissions from the Energy Roadmap 2050 scenarios were provided for electricity and steam production combined, the sector's carbon intensity was multiplied by the total electricity generation to obtain the emissions from electricity generation only.

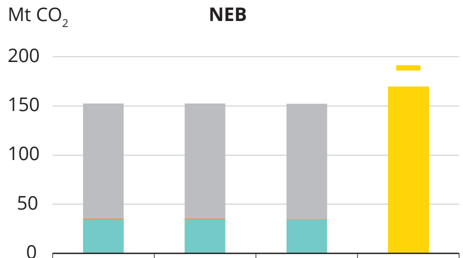
Figure 2.11 Comparison of current regional carbon dioxide emission profiles, 2014/2015, by fuel type (Mt CO_2)



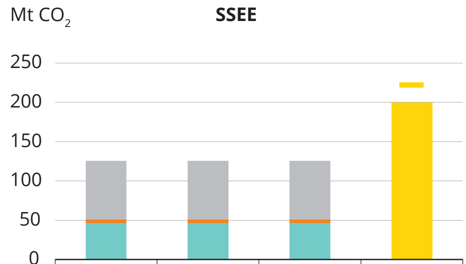
	EXT	AVG	REV	Top-down adjusted
Energy roadmap adj	N/A	N/A	N/A	162
Solid	84	84	84	
Oil	0	0	0	
Gas	2	2	2	
Non-adjusted top-down	N/A	N/A	N/A	180



	EXT	AVG	REV	Top-down adjusted
Energy roadmap adj	N/A	N/A	N/A	284
Solid	176	176	176	
Oil	4	4	4	
Gas	29	29	28	
Non-adjusted top-down	N/A	N/A	N/A	316



	EXT	AVG	REV	Top-down adjusted
Energy roadmap adj	N/A	N/A	N/A	170
Solid	117	117	117	
Oil	1	1	1	
Gas	34	34	34	
Non-adjusted top-down	N/A	N/A	N/A	189



	EXT	AVG	REV	Top-down adjusted
Energy roadmap adj	N/A	N/A	N/A	200
Solid	75	75	75	
Oil	5	5	5	
Gas	46	46	46	
Non-adjusted top-down	N/A	N/A	N/A	222

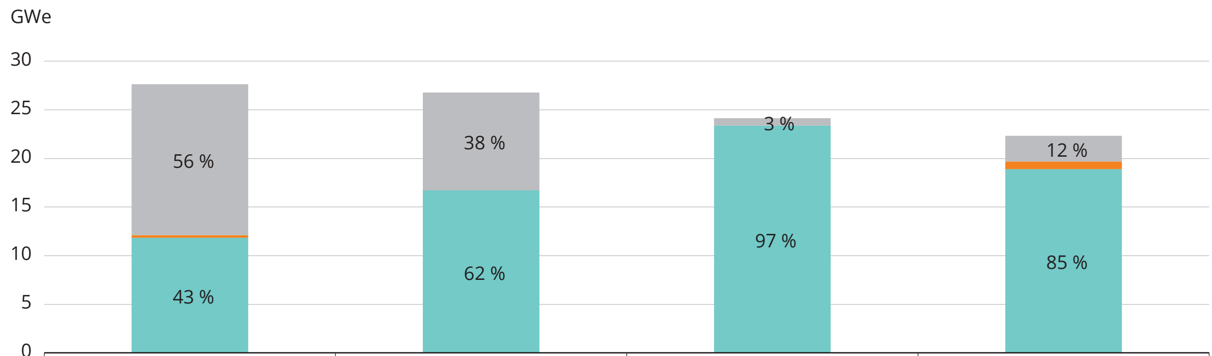
Note: Bottom-up results shown for 2014, for the EU-27; top-down (Roadmap adjusted) results shown for 2015, adapted to account for the 200 MWe capacity threshold.

Source: EEA (based on Platts, 2014; and EC, 2011c).

2.4.4 *EU and regionally planned fossil fuel capacity up to 2030*

While the Platts database is not a forecasting tool, it does provide interesting information regarding planned fossil fuel units up to 2030 (both units under construction and planned units). According to that information, the region with the most planned fossil fuel capacity is CEE, closely followed by NEB (Figure 2.12). In all regions, except CEE, most new fossil fuel capacity that is already planned or under construction is gas fired. Significant coal-fired capacity is planned in CEE, with a notable absence of coal-fuelled units in NEB ([27]).

Figure 2.12 Additional fossil fuel capacity to be installed from 2015 to 2030, by region (GWe)



	CEE	CWE	NEB	SSEE
Solid	16	10	1	3
Oil	0	0	0	1
Gas	12	17	23	19

Note: The graph shows the additional fossil fuel capacity (≥ 200 MWe) that is expected to be installed in the EU-28 by 2030 (capacity in the year 2015 is included).

Source: EEA (based on Platts, 2014).

([27]) Nuclear energy is relied on most heavily in NEB, whereas SSEE has no nuclear energy capacity planned in the next 15 years.

3 Hypothetical pathways

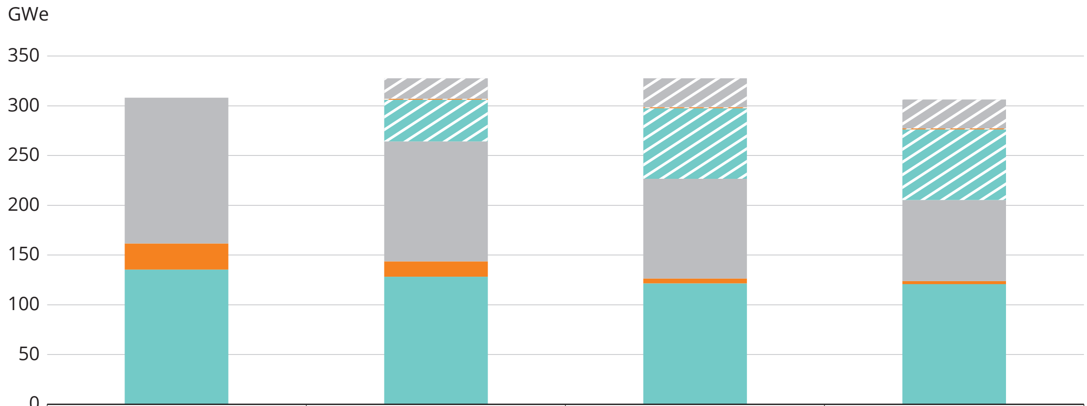
Chapter 2 presented the main characteristics and profiles of the information in the bottom-up database for the power sector in Europe and across four aggregated EU regions. Building on that, and on a number of other relevant parameters — such as the technical lifetime of the units, the future investment plans captured in the bottom-up analysis through information in the Platts database, and the anticipated need for upgrading of some units to comply with air pollutant requirements — this chapter constructs potential decommissioning pathways for the power sector in Europe and across the four selected regions.

Firstly, an analysis of the need for technological upgrading across the sector to meet future air emission requirements under the IED is described in Section 3.1. Capturing these is relevant, because, from a climate perspective, such investments could result in a greater degree of lock-in and more stranding of carbon-intensive European power plants in future. Secondly, the hypothetical evolution of the power sector is illustrated in Section 3.2 with the aid of the complementary capacity decommissioning pathways that take into account the selected technical lifetime assumptions.

The assessment of the need for upgrading to meet the IED requirements (i.e. the revised decommissioning path — REV) identified a possible 37.4 GWe of fossil fuel capacity to be closed by 2024, representing 12 % of the total operational fossil fuel capacity in 2014. At the same time, it identified that 75.5 GWe of fossil fuel capacity could be renovated in order to comply with the IED ELVs — the equivalent of roughly 25 % of the total operational fossil fuel capacity in 2014.

Overall, a staggering 67 % of current capacity could remain operational up to and beyond 2030 under the extended lifetime assumptions, representing a considerable commitment towards our future energy profile (Figure 3.1). In the context of path dependency, this is an extremely important consideration with likely implications for the smooth and efficient integration

Figure 3.1 Installed capacity in the EU-28 by fuel type (GWe)



	2014	2020	2025	2030
Solid (planned)	0	21	29	29
Oil (planned)	0	1	1	1
Gas (planned)	0	42	71	71
Solid	147	121	100	82
Oil	26	15	5	3
Gas	135	128	121	121

Source: EEA (based on Platts, 2014).

of the EU electricity market. While only 11 % of current oil-fuelled units are expected to be still operational by 2030, 89 % of gas-fired units have the capacity to remain operational over the next 15 years. For coal-fired units, 56 % of current capacity is expected to be operational in 2030.

3.1 Revised decommissioning path reflecting potential need for upgrading to meet IED emissions requirements

As it is responsible for 45 % of sulphur dioxide (SO_2) emissions, and 18.5 % of nitrogen oxide (NO_X) emissions, the power sector accounts for a considerable share of overall air pollution in Europe ([28]). In order to reduce emissions from these installations and minimise the associated health and environmental impacts, the IED is strengthening the ELVs for certain air pollutants ([29]). Power plant operators will have to decide whether or not and when to make further investments to ensure compliance with the IED ELVs. To enable smoother transition to the stricter ELVs, the IED provides a set of flexibilities through the transitional national plan, the provisions regarding the limited lifetime derogation,, the transitional derogations for district heating plants, and the provisions with regard to plants operating in small isolated systems ([30]). Furthermore, a less stringent set of ELVs applies to peak load-only plants and units (less than 1 500 operating hours per year as a rolling average over a period of 5 years).

3.1.1 Overview of Industrial Emissions Directive emissions limit value exceedances

Units within the assessed fossil fuel power sector database, which are 'potential candidates for closure' or 'potential candidates for investment', were identified in this exercise. This assessment took as a starting point those units for which emissions in 2012 may have exceeded the IED ELVs for NO_X and SO_2 (emissions are reported as loads and have been converted to concentrations using fuel-specific flue gas volumes). Although the IED also specifies ELVs for dust and carbon monoxide emissions (the latter in the case of gas-fired plants only), measures to reduce the emissions of these substances are typically significantly less expensive than the investments needed to reduce SO_2 or NO_X emissions, and, as such, these were not taken into account in determining exceedances but are shown below for the sake of completeness. To accommodate uncertainties in emissions data and in the conversion to concentrations, only average annual emissions values that are at least 15 % higher than the (monthly) ELVs set in the IED were counted as indicating an exceedance (for details on methodology, see Amec Foster Wheeler, 2015).

Out of 540 plants selected in the LCP database, in accordance with the scope of the study and linked successfully to the units in the Platts database, 158 plants with a combined installed capacity of 112.9 GWe (36.7 % of operational fossil fuel capacity in 2014), were found to exceed either the NO_X or SO_2 ELVs, or both in 2012, based on the approach described above.

Figure 3.2 shows the results of this study compared with the results for the same set of large combustion plants (LCPs) from a recent study done for the Directorate-General for the Environment (DG ENV) (Amec Foster Wheeler, 2015), to which the same 15 % emissions exceedance threshold was applied to make it comparable with the approach adopted in the present report. A comparison of results by installed capacity is shown in Table 3.1. The results show that the majority of the plants that exceeded the NO_X ELVs also exceeded the SO_2 ELVs and vice versa.

This applied almost exclusively to solid fuel- and oil-fired plants, with only two gas-fired power plants registering an exceedance for SO_2. Furthermore, the results from the two studies show significant overlap: almost all plants registering a 15 % exceedance in the Amec Foster Wheeler study also registered a 15 % exceedance based on this assessment. The largest discrepancy was found in dust emissions, with this study finding around 56 % more plants exceeding the ELVs than the other study. The differences in the results are most likely to be due to minor differences in methodology and a similar, but not identical, selection of LCPs in the two studies ([31]).

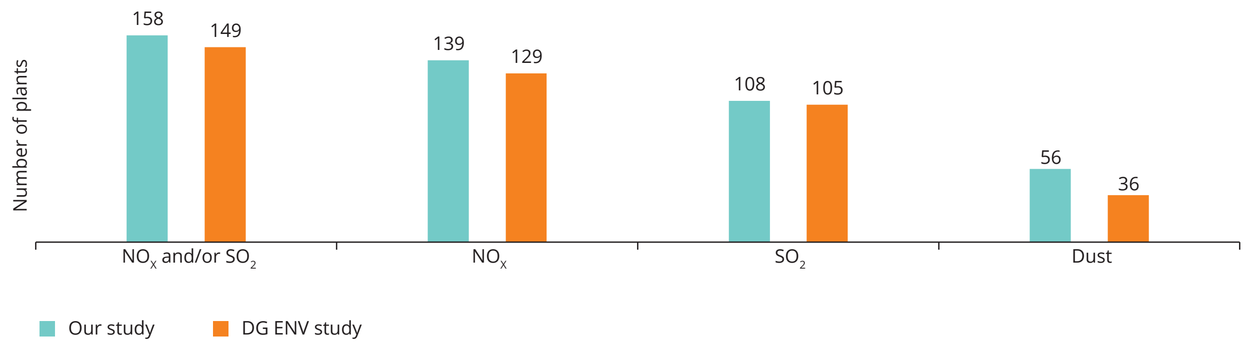
([28]) Within the EU-28 for 2012, EEA, http://www.eea.europa.eu/data-and-maps/data/data-viewers/air-emissions-viewer-lrtap.

([29]) For existing plants, the IED ELVs are listed in Part 1 of Annex V. The deadline for compliance is 1 January 2016. New plants (those put into operation after 7 January 2013) have to comply immediately with the stricter ELVs in Part 2 of Annex V of the IED.

([30]) Articles 32–35 of the IED. The approach provided by the transitional national plan was taken by 15 Member States (Bulgaria, Croatia, Czech Republic, Finland, Greece, Hungary, Ireland, Lithuania, Poland, Portugal, Romania, Slovakia, Slovenia, Spain and the United Kingdom), while 24 Member States will make use of the limited lifetime derogation (Belgium, Bulgaria, Croatia, Cyprus, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden and the United Kingdom).

([31]) In this study, data from the LCP dataset were combined with data from Platts WEPP database to further specify the fuel type used and more accurately determine the plant emission concentrations and applicable ELVs.

Figure 3.2 Number of LCPs exceeding IED ELVs for NO_X, SO_2 and dust



Source: EEA (based on the LCP-EPRTR database, Amec Foster Wheeler, 2015; and own calculations).

Table 3.1 Installed capacity (GWe) exceeding IED ELVs for NO_X, SO_2 and dust

Capacity (GWe)	NO_X and/or SO_2	NO_X	SO_2	Dust
This study	112.9	99.4	84.5	33.8
DG ENV study	109.6	95.8	84	20.6

Source: EEA (based on LCP-EPRTR database, Amec Foster Wheeler, 2015 and own calculations).

3.1.2 Approach and findings

Taking as a starting point the 158 LCPs that exceeded the ELVs for NO_X and/or SO_2, the plants were divided into two groups:

- Plants that have opted out under the LCP Directive, which are regarded as **potential candidates for closure,** as they were expected to close by the end of 2015. The same applies to plants that will be operating under a limited lifetime derogation from 2016 onwards (IED Article 33), which are also regarded as 'potential candidates for closure', as they are expected to close by 2024.
- Other plants, including those that are part of a transitional national plan (IED Article 32), which are regarded as **potential candidates for investment** (unless the transitional national plans indicate the contrary) and are assumed to invest in measures to reduce emissions and ensure compliance with the IED, irrespective of the age of the plant or the costs of upgrading.

At a later stage, the assessment of unit technical lifetimes, as described above, was used to further extend the plant classification procedure.

Table 3.2 gives an overview of the allocation results and the electricity capacity represented by the plants.

Based on these preliminary results, a total installed capacity of 37.4 GWe (representing 33 % of capacity exceeding the IED ELVs and 12 % of total operational fossil fuel capacity in 2024) may potentially be closed by 2024.

Table 3.2 Preliminary allocation of LCPs and their installed capacity

Status	Number of LCPs	Installed capacity (GWe)	Allocation
LCP Directive opt-out ([a])	24	16.2	Potential candidates for closure
Limited lifetime derogation	24	21.2	Potential candidates for closure
Transitional national plan	51	43.4	Potential candidates for investment
Other	59	32.1	Potential candidates for investment
Total plants with IED exceedance	**158**	**112.9**	
Total number of plants ≥ 200 MWe	**540**	**411**	

Note: ([a]) May include partial closure.

Source: EEA (based on the LCP-EPRTR database and own calculations).

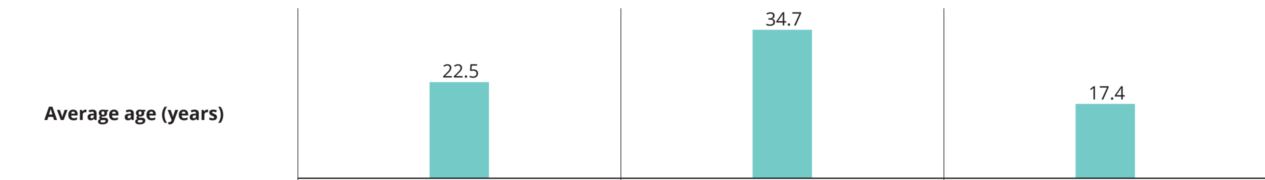
Profile of the large combustion plants with Industrial Emissions Directive exceedances

The average age of the plants with exceedances was higher than that of plants that comply with the IED ELVs (Figure 3.3), probably because of the tightening of emissions standards and the improvement in plants' mitigation capabilities over time.

Gas plants had the least IED ELV exceedances, with only 8 % of the operational plants registering an exceedance (Figure 3.4). Exceedances were much more prevalent among other plant types, with 58 % of solid fuel plants and 55 % of liquid fuel plants exceeding one or both IED ELVs. Of the solid fuel plants, 41 % exceeded both NO_X and SO_2 regulations. Among multi-fuel plants, 50 % were in exceedance ([32]). Furthermore, NO_X exceedances were slightly more common than SO_2 exceedances, especially in gas-fired plants, of which 8 % of operational plants exceeded the NO_X ELVs while only 1 % exceeded the SO_2 ELV. It is not certain how these SO_2 exceedances were caused in the gas-fired plants.

CEE had the highest rate of exceedances (Figure 3.5), with 78 % of all operational plants exceeding the IED ELVs, while CWE and SSEE had the lowest rates (around 20 % of all LCPs in exceedance). The NEB region had around 35 % of LCPs in exceedance.

Figure 3.3 Comparison of the average age of LCPs with ELV exceedances

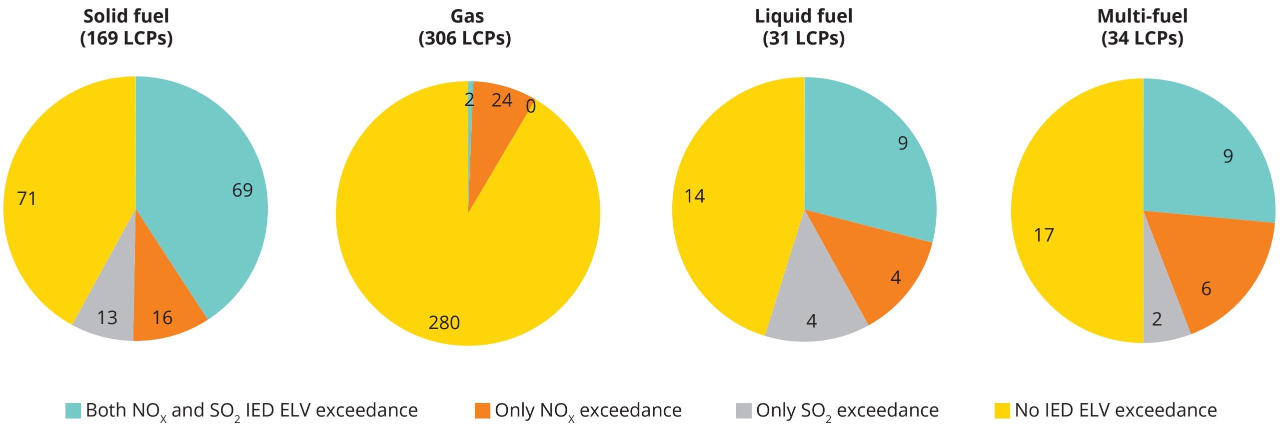


	All plants	Plants with IED ELV exceedance (NO_x and/or SO_2)	Plants with no IED ELV exceedance
Average age (years)	22.5	34.7	17.4
Share of operational capacity (%)	100	38	62
Capacity (GWe)	294.1	112.9	181.2

Source: EEA (based on the LCP-EPRTR database and own calculations).

([32]) Multi-fuel plants are defined in this study as plants in which the main fuel represented less than 95 % of the fuel input in 2012.

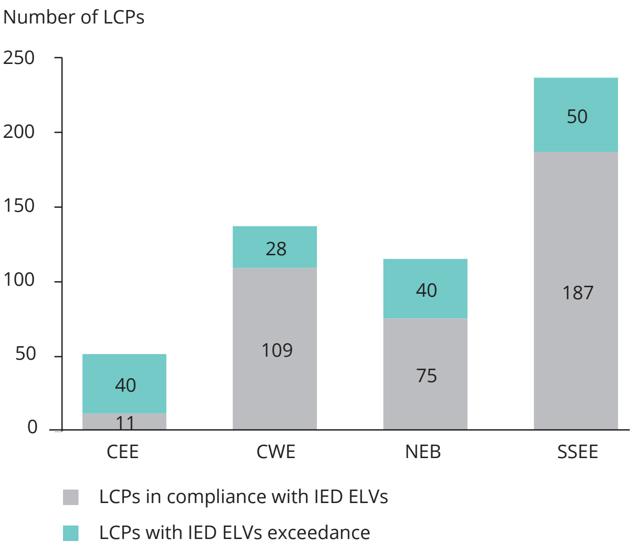
Figure 3.4 IED ELV exceedances by fuel type (number of LCPs)



Note: Exceedances were calculated based on 2012 emissions data.

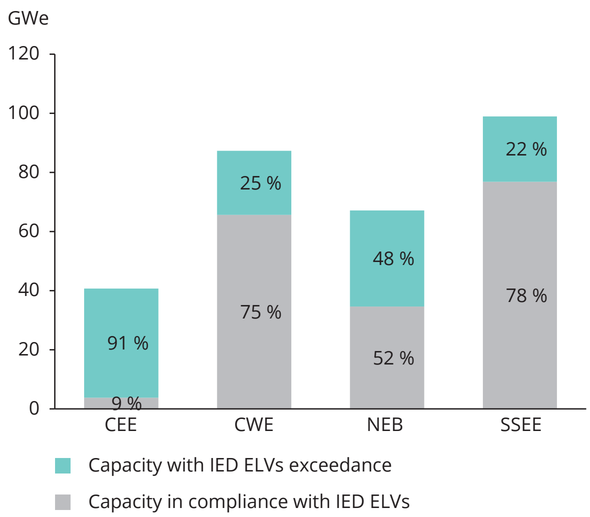
Source: EEA (based on the LCP-EPRTR database and own calculations).

Figure 3.5 Number of LCPs with and without IED ELV exceedances, by region



Source: EEA (based on the LCP-EPRTR database and own calculations).

Figure 3.6 Installed capacity with and without IED ELV exceedances, by region



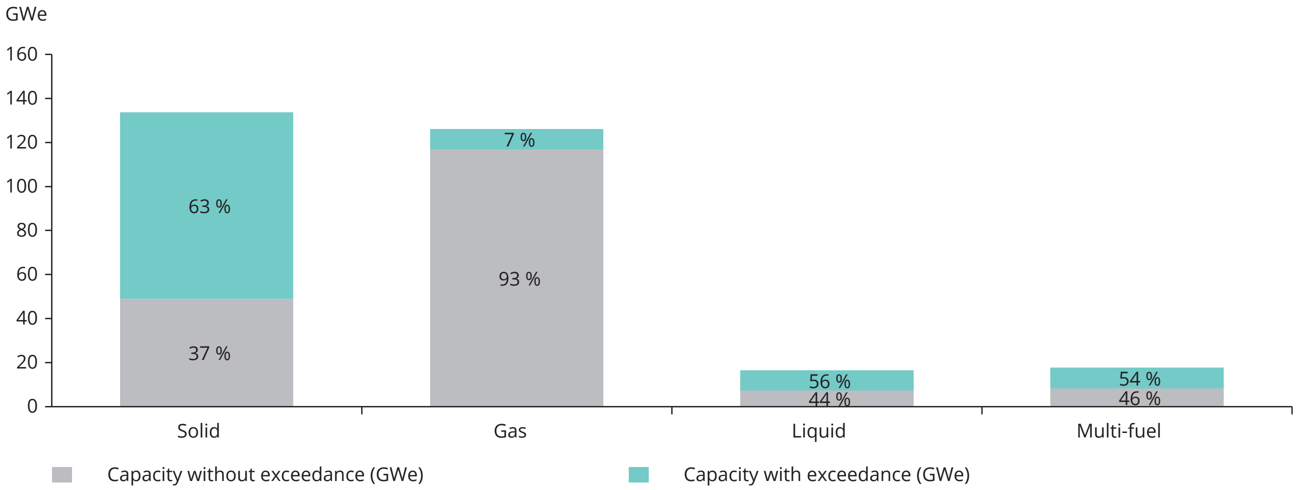
Source: EEA (based on the LCP-EPRTR database and own calculations).

Figure 3.6 illustrates the regional distribution of IED ELV exceedances, by capacity. Accordingly, in CEE, 37 GWe (or 90 % of all installed capacity) was expected to exceed one or both IED ELVs. NEB was the region with the second-highest expected exceedances, with 33 GWe (close to 50 % of all installed capacity). SSEE and CWE had roughly equal numbers of expected IED ELV exceedances, of approximately 22 GWe each (or between 22 % and 25 % of all installed regional capacity).

With regard to total installed capacity, exceedances by type of fuel were highest for solid fuel-fired capacity (63 %), followed by exceedances for liquid fuel and multi-fuel plants (56 % and 54 %, respectively), whereas exceedances for natural gas plants were minimal (7 %), as shown in Figure 3.7.

A detailed overview of the results of this assessment, by region and by country, is presented in Table 3.3.

Figure 3.7 IED ELV exceedances in installed capacity by fuel type (GWe and % share)



Source: EEA (based on the LCP-EPRTR database and own calculations).

3.2 Hypothetical decommissioning pathways

As explained in the previous section, this assessment looked at the currently expected, longer (extended), technical lifetimes of large fossil fuel units, and considered their need for upgrading to comply with air emissions requirements, to improve our understanding of these potential decommissioning paths and to illustrate their implications for the sectoral decarbonisation process planned for the run-up to 2050.

3.2.1 Assessment of expected technical lifetime

Given the long lifetime of power plants and their associated infrastructure, understanding the likely **technical lifetime** of individual units is among the most relevant parameters to estimate the potential future evolution of the sector from this **technical lifetime perspective**.

To identify robust technical lifetime values to be used in the bottom-up assessment, a triangulation approach was carried out in four different steps:

- Firstly, an initial literature review was conducted.
- Secondly, an assessment of average expected lifetimes of operational power plants was carried out, based on the information in the PPT database (Enerdata, 2015).
- Thirdly, based on information from Platts (2014), the commissioning and decommissioning dates for already retired units were studied in order to identify their average historic operating lifetime.
- Finally, the age profile of the current fossil fuel power sector was reviewed using Platts (2014).

This assessment resulted in the two variants shown in Table 3.4. The AVG profile suggests that, by 2015, 30 % of the currently operational capacity under assessment should have already been decommissioned. However, this is not in line with reality. In conclusion, the majority of the plants operating now will remain operational for longer periods of time than has been the case so far. Therefore, we chose to use the extended values (EXT profile) as the main values for this assessment, using the median variant (AVG profile) only to conduct a sensitivity analysis, which is shown throughout the report. It is worth mentioning that this lifetime assessment did not include political and economic factors, such as the tightening of the ETS cap and the effects of other policies or of international factors. It focuses entirely on the currently expected, longer, technical lifetime to shed maximum light on the potential consequences should fossil fuel units be allowed to operate over their full technical lives.

Table 3.3 Country results for IED ELV exceedances

	Capacity (MWe)			Number of LCPs				
	Before consultation			Before consultation			After consultation	
	No exceedances	Exceedances	Total	No exceedances	Exceedances	Total	Current exceedances	Closed exceedances
CEE	**3 781**	**36 953**	**40 734**	**10**	**40**	**51**	**38**	**0**
BG (Bulgaria)		4 143	4 143		5	5	5 ([a])	–
CZ (Czech Republic)	816	3 520	4 336	1	5	6	5	–
HR (Croatia)	210	740	950	1	3	4	3	–
HU (Hungary)	928	636	1 564	2	1	3	1	–
PL (Poland)		21 174	21 174		13	13	11	–
RO (Romania)	1 827	5 965	7 792	6	12	18	12	–
SI (Slovenia)		345	345		1	1	1	–
SK (Slovakia)	430		430	1	0	1	0	–
CWE	**65 614**	**21 681**	**87 295**	**109**	**28**	**137**	**25**	**1**
AT (Austria)	2 981	250	3 231	7	1	8	1 ([a])	–
BE (Belgium)	3 112	294	3 406	10	1	11	0	1
DE (Germany)	42 560	10 980	53 540	56	14	70	14 ([a])	–
FR (France)	4 823	9 651	14 474	9	11	20	10	–
LU (Luxembourg)	385		385	1		1	0	–
NL (Nehterlands)	11 753	506	12 259	26	1	27	0	–
NEB	**34 587**	**32 566**	**67 153**	**75**	**40**	**115**	**38**	**0**
DK (Denmark)	3 335	1 636	4 971	8	3	11	1	–
EE (Estonia)		1 610	1 610		1	1	1	–
FI (Finland)	1 290	950	2 240	4	4	8	4 [(a)]	–
IE (Ireland)	2 183	1 685	3 868	6	5	11	5	–
LT (Lithuania)	1655		1 655	1		1	0	–
LV (Latvia)	535		535	1		1	0	–
SE (Sweden)	1 750		1 750	4		4	0	–
UK (United Kingdom)	23 839	26 685	50 524	51	27	78	27[(a)]	–
SSEE	**76 808**	**22 105**	**98 912**	**187**	**50**	**237**	**47**	**3**
EL (Greece)	3 429	4 497	7 925	9	12	21	12	–
ES (Spain)	27 943	9 498	37 441	67	18	85	17	1
IT (Italy)	40 355	7 440	47 795	102	18	120	16	2
PT (Portugal)	5 081	670	5 751	9	2	11	2	–
Total	**180 789**	**113 304**	**294 094**	**381**	**158**	**540**	**148**	**4**

Note: ([a]) No response from the Member State.

Source: EEA (based on the LCP-EPRTR database, the results of Eionet consultation and own calculations).

Table 3.4 Lifetime values by type of fuel

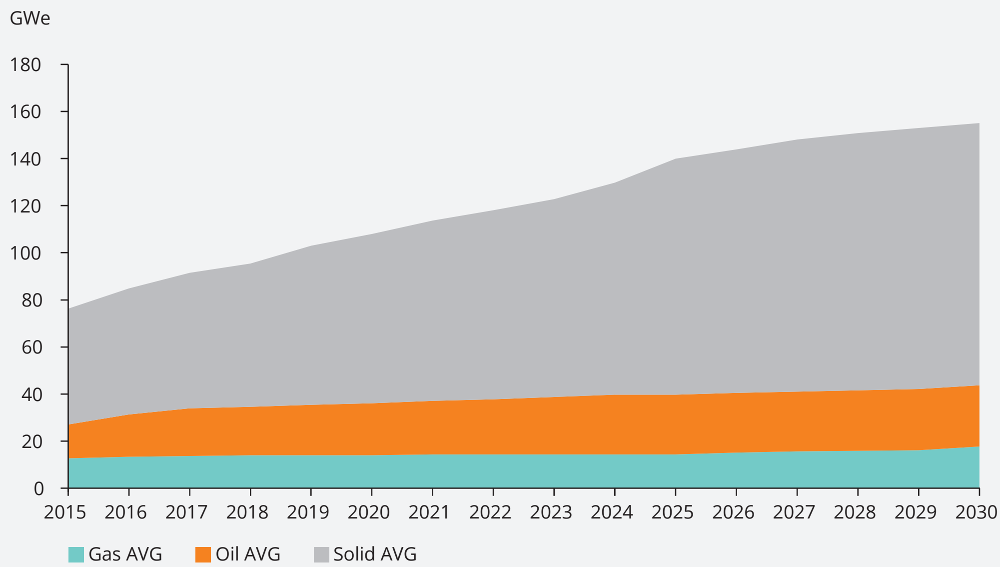
Power plant fuel	Medium lifetimes (AVG profile)	Extended lifetimes (EXT profile)
Coal	40 years	50 years
Gas	35 years	45 years
Oil	40 years	50 years
Nuclear	50 years	60 years

The selected lifetime values are based on the technical lifetimes of the units per type of fuel, as well as on their real operating lifetimes and an assessment of the effect of the expected decommissioning on the units currently operating. These lifetimes were added to the individual commissioning years to obtain the expected decommissioning year of each unit. If this was earlier than 2015, then 2015 was assumed to be the decommissioning year.

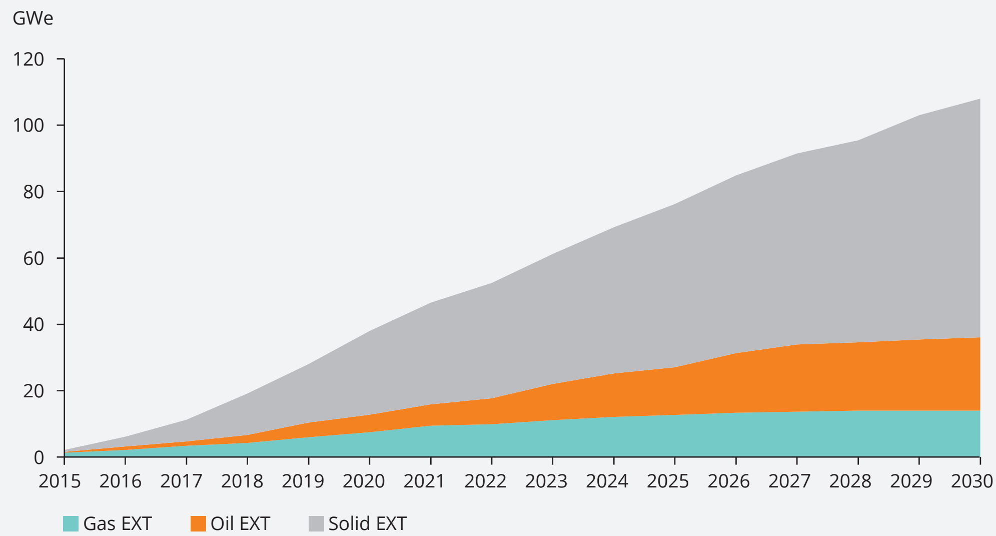
Box 3.1 EU capacity decommissioning under extended and average lifetime trends

Selecting the medium operating lifetime variant (AVG) would imply that 30 % of the capacity ≥ 200 MWe would already have been decommissioned by 2015. Given these unrealistic levels of decommissioning, the extended lifetimes presented in Table 3.4 were chosen as working assumptions for this study. Therefore, these are the values used when presenting the revised results following consultation with Member States. The variant (AVG) is also presented, as a sensitivity analysis.

Extended lifetime trends (EXT)



Medium lifetime trends (AVG)



Source: EEA (based on Platts, 2014).

Extended lifetime findings

The hypothetical evolution of the power sector obtained on the basis of the expected, longer, lifetimes shows that, for all regions, most of the retired capacity over the next 15 years would come from coal-fired units. Accordingly, 72 GWe of coal-fired units are expected to retire in the next 15 years (or 111 GWe in the AVG profile), while 21 GWe are expected to be installed. This would lead to a net retirement of 51 GWe of coal-based capacity (or 90 GWe under the AVG profile).

Oil would also undergo significant retirement, second only to coal, with 22 GWe of capacity to be retired (26 GWe in the AVG profile), compared with a negligible amount to be installed.

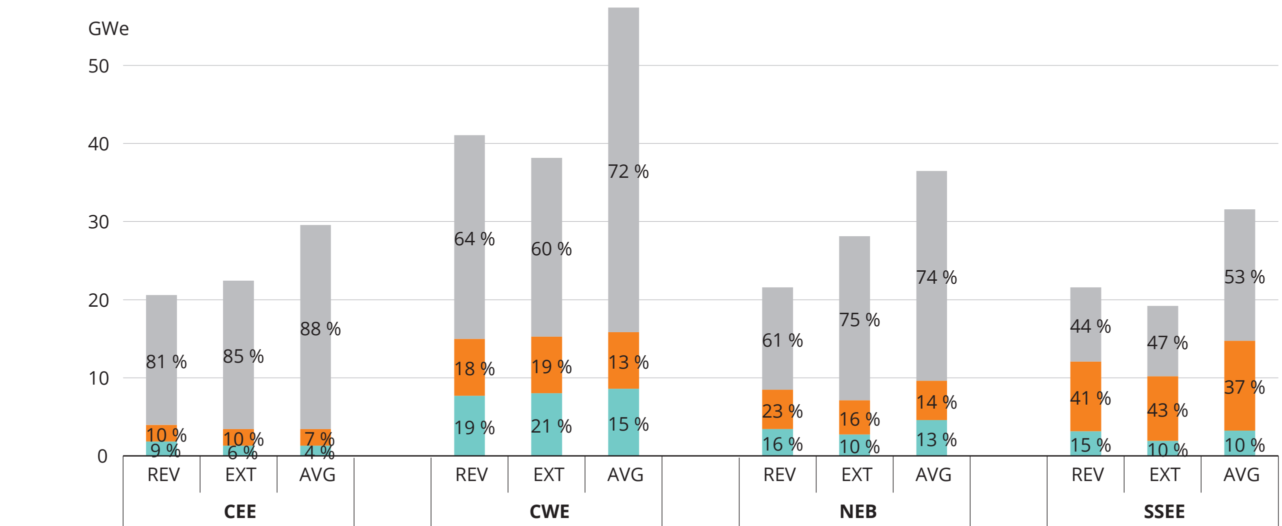
Gas would see retirement of only 14 GWe of capacity (18 GWe in the AVG profile), compared with 66 GWe to be installed over the period, leaving a net installation of 52 GWe of capacity between 2015 and 2030 (or 48 GWe when using the AVG profile). This shift in fuel type leads to an overall decarbonisation of the sector due to the replacement of coal-fired units by gas-fired units, which are less carbon-intensive.

3.2.2 Adjusted decommissioning pathways due to air emissions requirements

In addition to the previous bottom-up sectoral profiles that consider only the different technical lifetimes (EXT and AVG profiles), a revised (REV) sectoral profile was calculated, building on the one with the expected, longer, lifetimes (EXT), but also taking into account potential capacity upgrades and closures to comply with stricter ELVs for certain air pollutants under the IED, as indicated in Section 2.4. Figure 3.8 presents the results by region for both the EXT and the REV profiles, using extended lifetimes and revised technical lifetimes.

The hypothetical sectoral decommissioning pathways obtained on the basis of the different bottom-up assessments (EXT, AVG and REV profiles) are illustrated graphically in Figure 3.9.

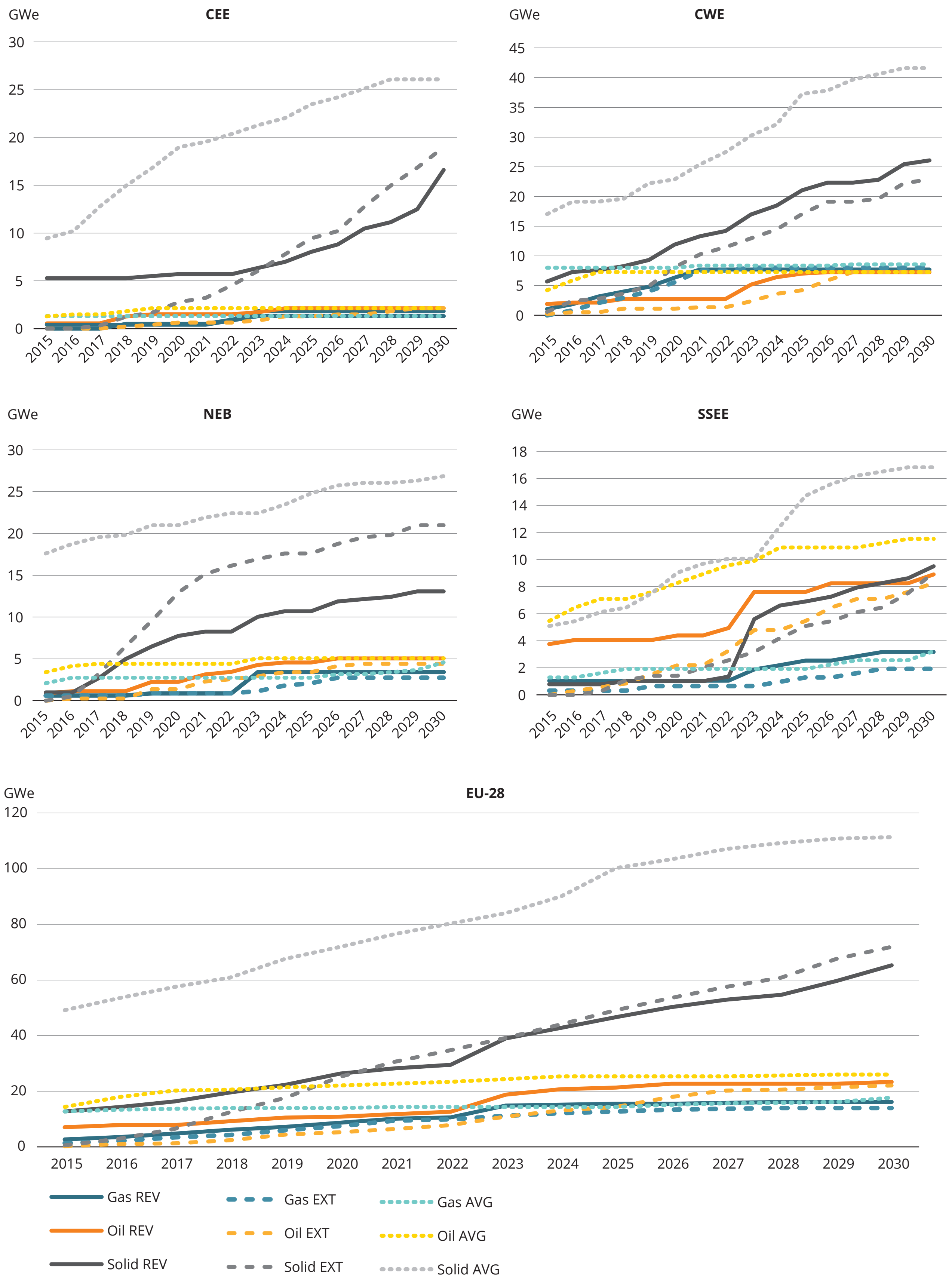
Figure 3.8 Decommissioning of regional capacity (due to EXT and REV lifetimes) from 2015 to 2030



	CEE REV	CEE EXT	CEE AVG	CWE REV	CWE EXT	CWE AVG	NEB REV	NEB EXT	NEB AVG	SSEE REV	SSEE EXT	SSEE AVG
Solid (MWe)	16 617	18 992	26 092	26 096	22 878	41 597	13 083	20 983	26 848	9 500	9 035	16 818
Oil (MWe)	2 137	2 137	2 137	7 275	7 275	7 275	5 056	4 396	5 056	8 909	8 269	11 529
Gas (MWe)	1 828	1 320	1 320	7 716	8 016	8 592	3 432	2 746	4 579	3 164	1 924	3 224

Source: EEA (based on Platts, 2014; Member States' responses and own calculations).

Figure 3.9 EXT and REV decommissioning pathways (by region and fuel, covering EU-28 capacity up to 2030)



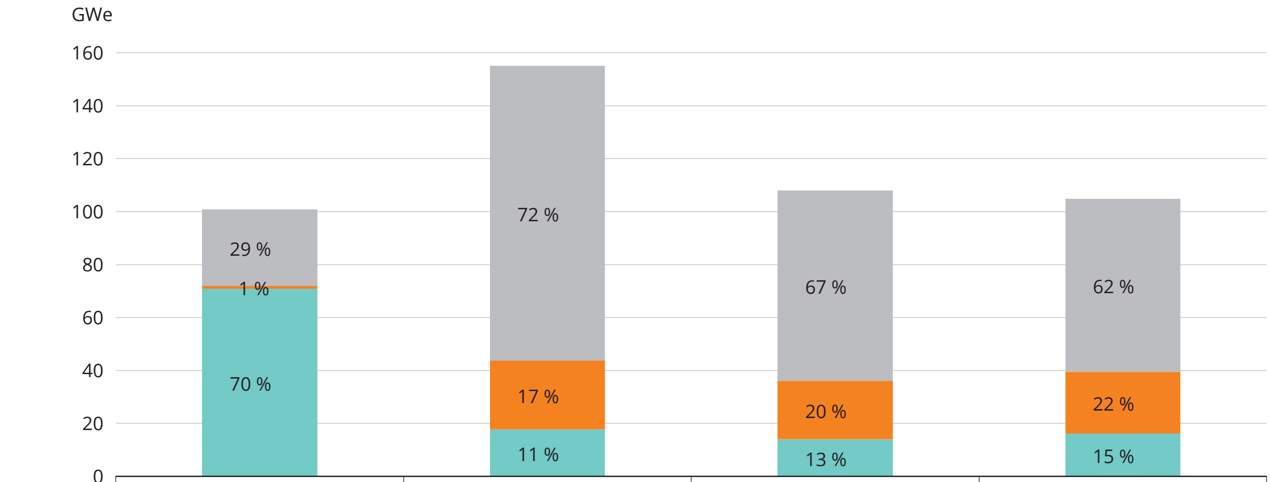
Source: EEA (based on Platts, 2014; Member States' responses and own calculations).

Revised lifetime findings

Taking into account both the expected and the revised decommissioning paths, the main insights can be summarised as follows:

- While the pathways eventually catch up with each, the REV pathway generally sees a slight delay in the decommissioning of fossil fuel capacity over the short term. The AVG pathway, on the other hand, anticipates faster decommissioning than the alternative pathways.
- Across the EU-28, 108 GWe of fossil fuel capacity is expected to be technically decommissioned over the next 15 years ([33]). Considering the AVG pathway, 155 GWe of capacity is expected to be decommissioned by 2030. This drops to 105 GWe (of which 4 GWe had already been decommissioned before 2015) when the need for technological upgrading across the sector to comply with the IED ELVs is taken into consideration in the REV pathway. In this pathway, 18 GWe of capacity is expected to be decommissioned at a later stage, pointing to the need for technological upgrading, while 37.5 GWe of capacity is expected to be decommissioned earlier, pointing to closures due to failure to comply with the IED ELVs.
- Overall, decommissioning of coal-based capacity is expected to occur at a slightly faster pace, compared with decommissioning of gas-fired capacity.
- The NEB region shows the greatest change in trends, with the revised decommissioning pathway for solid fuel-fired capacity indicating the retirement of coal plants at a much later stage — in other words a considerable upgrading of current capacity in order to comply with the stricter ELVs under the IED in future.
- Of the fossil fuel capacity assessed, around 101 GWe of capacity is planned and under construction ([34]). For the revised decommissioning pathway (REV), the realisation of unit upgrades would lead to a net overall increase in fossil fuel capacity of 4–7 GWe (REV over EXT pathways) over the period from 2015 to 2030.

Figure 3.10 Comparison between the expected decommissioning of units and planned units up to 2030 (GWe)



	Planned capacity up to 2030	Decommissioning up to 2030 AVG	Decommissioning up to 2030 EXT	Decommisioning up to 2030 REV
Solid	29	111	72	65
Oil	1	26	22	23
Gas	71	18	14	16

Source: EEA (based on Platts, 2014; Member States' responses and own calculations).

([33]) Croatia is included in this sectoral picture, as there is no comparison with the data from the Energy Roadmap 2050 here.
([34]) This statement relies on the accuracy of planning predictions from the databases used for this study, the reliability of which is not definite.

In detail, the revised decommissioning path (REV) would see:

- a net increase in gas-fired capacity of 55 GWe (a 40 % increase over 2014 installed capacity for gas);
- a net decrease in oil-fired capacity of 22 GWe (87 % over 2014 installed capacity for oil);
- a net decrease in solid fuel-fired capacity of 36 GWe (equal to a 25 % reduction compared with 2014 installed capacity for solid fuels).
- Of the additional fossil fuel capacity, only 12.2 GWe was 'under construction' in 2014, according to the information in the Platts database, while 'planned' units amounted to 87.2 GWe capacity ([35]).

3.2.3 *Installed capacity in the bottom-up decommissioning pathways*

This section focuses on the hypothetical medium-term evolution of the power sector, considering both the expected technical decommissioning under the EXT pathway and the revised decommissioning to ensure compliance with the IED ELVs, under the REV pathway, and in both cases the additional planned capacity.

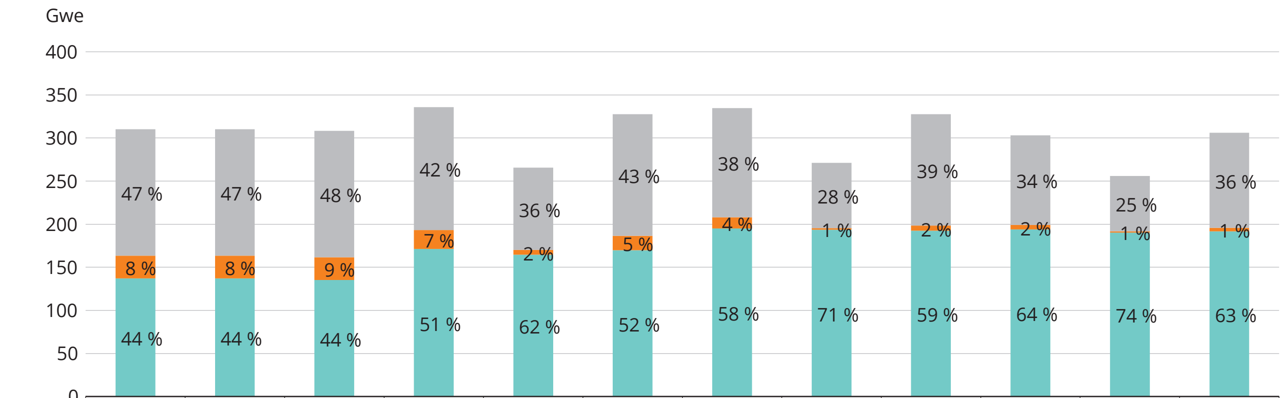
Figure 3.11 presents the sectoral profiles in 2014, 2020 and 2030, in terms of installed capacity by fuel type, according to the extended and revised decommissioning pathways described above. It can be seen that:

- solid fuel-fired capacity gradually declines across each time period in both absolute numbers and relative proportions;
- the proportion of gas-fired capacity increases significantly, from 44 % in 2014 to 64 % in 2030 in the EXT pathway (or to 74% in the AVG pathway), comprising a large proportion of the capacity profile in 2030;
- oil-based capacity is slowly phased out — from around 8 % to a negligible proportion;
- there are no significant differences between the 2030 EXT and REV bottom-up profiles, with only small changes in fuel proportions after 2020.

Regionally, there are also patterns in the evolution of operational installed capacity, as shown in Table 3.5:

- while all regions show an increase in the proportion of gas-fired capacity over time, NEB and SSEE show

Figure 3.11 Installed capacity expected to remain operational up to 2030 by fuel type in the EU-28



	EXT 2014	AVG 2014	REV 2014	EXT 2020	AVG 2020	REV 2020	EXT 2025	AVG 2025	REV 2025	EXT 2030	AVG 2030	REV 2030
Solid	147	147	147	142	96	141	127	76	129	104	65	111
Oil	26	26	26	22	5	17	13	2	6	5	1	4
Gas	137	137	135	171	165	170	195	193	192	194	190	192

Source: EEA (based on Platts, 2014; Member States' responses and own calculations).

([35]) The Platts WEPP 2014 database defines units under construction as those for which 'physical site construction is under way' and planned units as those which are 'still in planning or design'.

Table 3.5 Installed fossil fuel capacity expected to be operational up to 2030 under the EXT pathway, including revised decommissioning trends (REV pathway, in brackets), in the EU-28, by fuel type and region (GWe)

	Gas EXT (REV)	Oil EXT (REV)	Solid fuel EXT (REV)	Total EXT (REV)
Capacity of operational plants in 2014	**137 (135)**	**26 (26)**	**147 (147)**	**310 (308)**
CEE	4 (4)	2 (2)	32 (32)	39 (39)
CWE	33 (32)	8 (8)	62 (61)	103 (101)
NEB	34 (33)	5 (5)	29 (29)	67 (67)
SSEE	65 (65)	12 (12)	25 (25)	102 (102)
Capacity of operational plants in 2020	**171 (170)**	**22 (17)**	**142 (141)**	**336 (328)**
CEE	11 (11)	2 (1)	40 (37)	53 (49)
CWE	39 (38)	7 (5)	62 (58)	107 (101)
NEB	46 (46)	4 (3)	16 (21)	66 (70)
SSEE	75 (75)	10 (8)	25 (25)	110 (108)
Capacity of operational plants in 2025	**195 (192)**	**13 (6)**	**127 (129)**	**335 (328)**
CEE	15 (14)	1 (0)	38 (40)	54 (54)
CWE	42 (42)	3 (1)	55 (51)	100 (94)
NEB	55 (54)	2 (0)	12 (19)	68 (73)
SSEE	83 (82)	7 (5)	22 (20)	112 (107)
Capacity of operational plants in 2030	**194 (192)**	**5 (4)**	**104 (111)**	**303 (306)**
CEE	15 (14)	0 (0)	29 (31)	44 (46)
CWE	42 (42)	0 (0)	49 (46)	91 (88)
NEB	54 (54)	1 (0)	8 (16)	63 (70)
SSEE	82 (81)	4 (3)	18 (18)	105 (102)

Source: EEA (based on Platts, 2014; Member States' responses and own calculations).

the steepest increase in the proportion of gas-fired capacity over time: from 37 % in 2014 to 52 % in 2030 and from 60 % to 73 %, respectively;

- on the other hand, CEE shows the steepest decrease in the proportion of coal-fired capacity: from 63 % in 2014 to 43 % in 2030.

3.2.4 Regional electricity generation profiles

This section summarises the regional findings regarding electricity generation (in TWh) according to the bottom-up revised (REV) assessment and the approach outlined in Chapter 1 (see Boxes 1.2 and 1.3). The EU-level profiles are presented in Chapter 4, compared with the cost-effective levels in the Energy Roadmap 2050. A sensitivity analysis of energy production based on the load factor applied is presented in Annex 1.

In brief, according to the bottom-up revised assessment (Figure 3.12) and the assumptions made:

- In CEE, solid fuels would see a gradual decline in the proportion of electricity produced over the period 2014–2030, dropping from 97 % (2014) to 80 % (2030). Gas would increase substantially over this period (with many units currently in the planning phase) and would comprise 20 % of the energy production mix by 2030.

- In CWE, gas-fired electricity production would grow steadily in absolute and relative terms over the period 2014–2030, comprising 34 % of the 2030 energy mix. Over the same period, solid fuel generation would drop from 80 % to 66 %.

- The NEB region would experience a considerable reduction in the proportion of solid fuel-fired generation in the 2030 power mix. The revised decommissioning pathway would see the proportion of solid fuel generation drop from 60 % in 2014 to 34 % in 2030. In addition, this region would experience a steady growth in natural gas-based energy generation, up to 66 % in 2030. Liquid fuel-based generation would, however, disappear by 2030 in the bottom-up revised decommissioning path.

- SSEE would experience a further increase in its already high share of gas-fired energy production, from 53 % to 65 % by 2030. Solid fuel generation would decrease steadily, from 45 % to 33 % by 2030, and energy production from oil would increase up to 2020 and then decline steadily up to 2030.

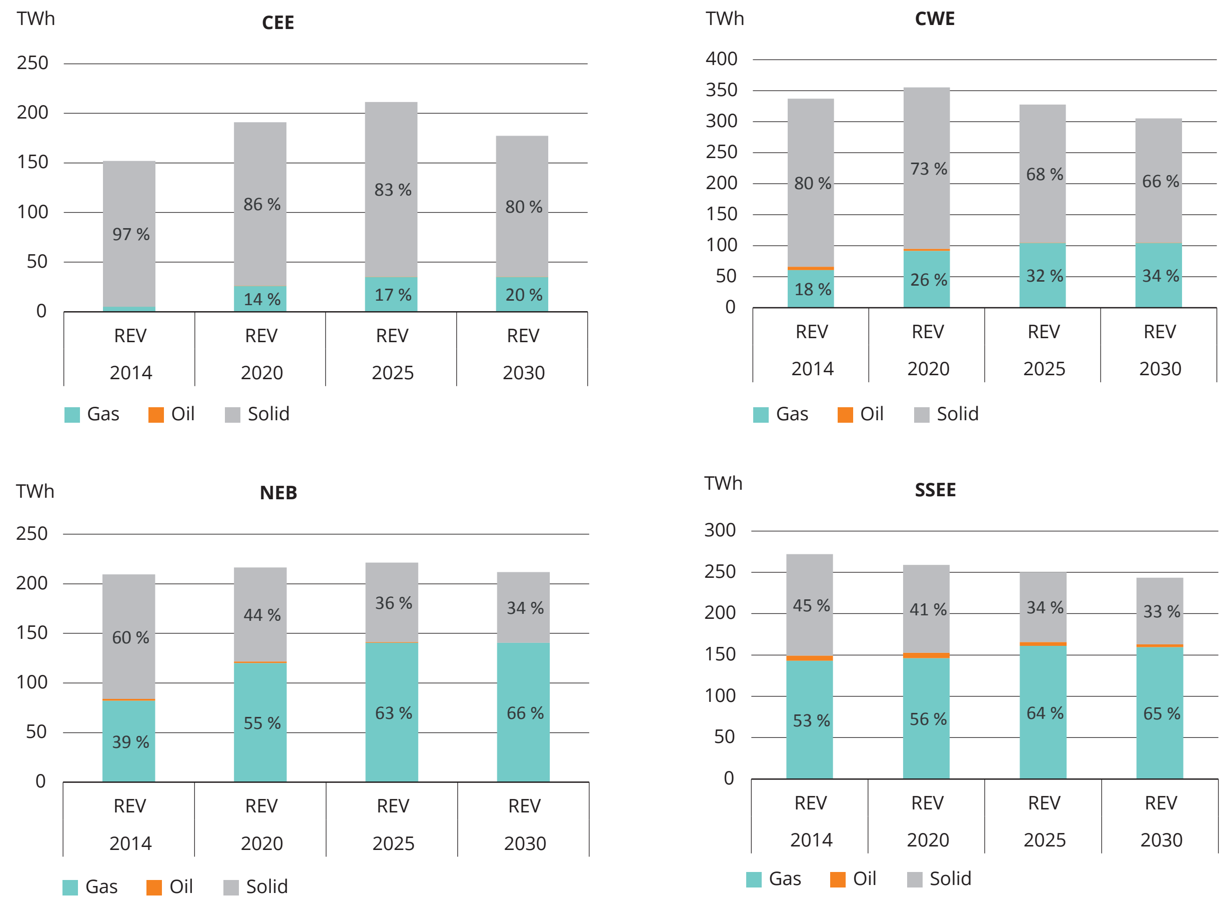
3.2.5 Regional carbon dioxide emissions profiles

This section presents the illustrative regional findings regarding carbon dioxide emissions, according to the bottom-up revised decommissioning path (REV). As in the previous section, the EU-level profile is shown in Chapter 4 in comparison with the cost-effective levels from the Energy Roadmap 2050.

In brief, the following insights emerge from the bottom-up revised pathway (Figure 3.13):

- For CEE, the high proportion and carbon intensity of solid fuel generation would dominate power-related carbon dioxide emissions up to 2030. The relative

Figure 3.12 Regional power mix profiles (REV pathway)



Note: Bottom-up results shown for EU-28.

Source: EEA (based on Platts, 2014, Member States' responses and own calculations).

share of carbon dioxide emissions from solid fuel generation would drop slightly, from 98 % in 2014 to 90 % in 2030, and be replaced by an increasing proportion of carbon dioxide emissions from gas-fired power, growing in both absolute and relative terms over the period 2014–2030. Furthermore, CEE is the only region where there would be a significant absolute increase in carbon dioxide emissions in 2020.

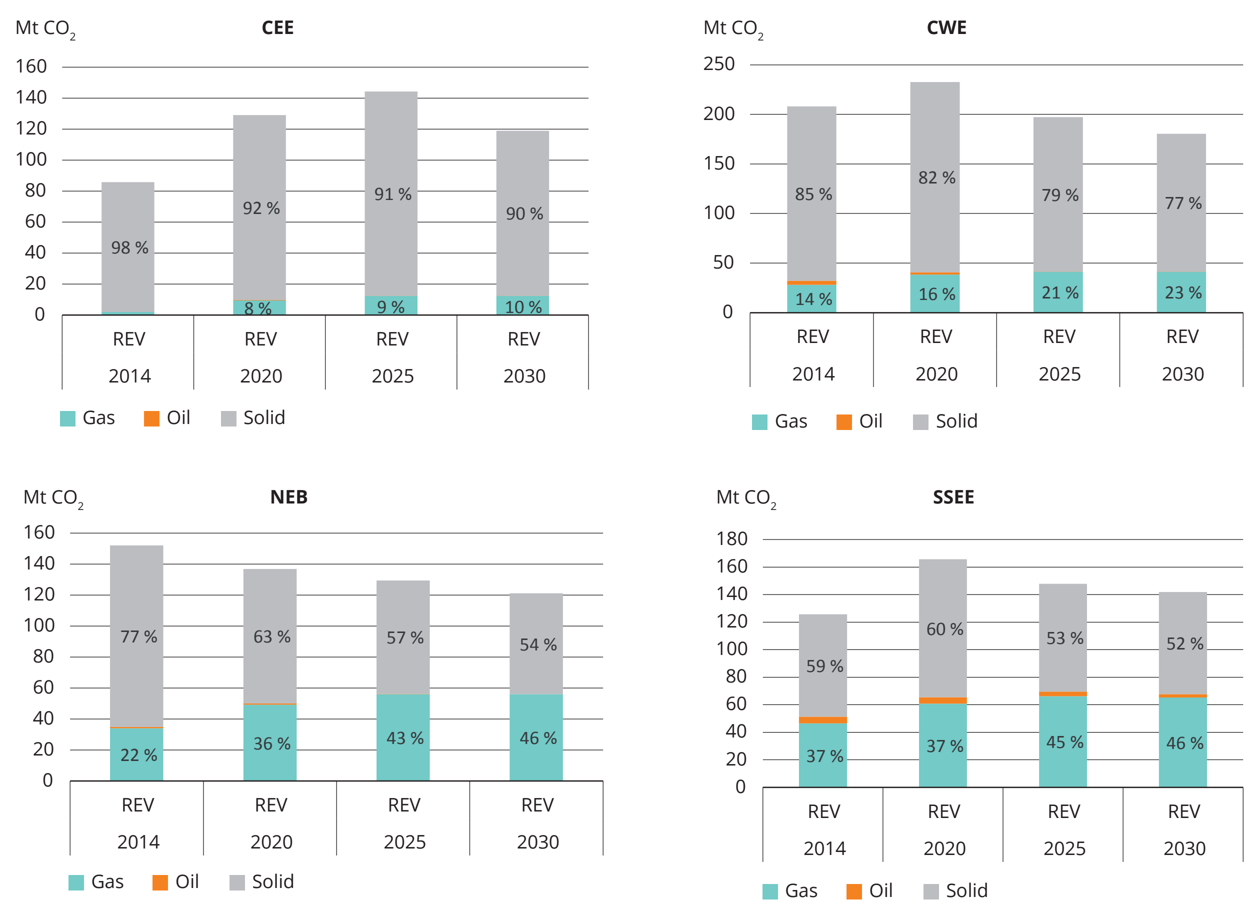
- CWE too would see solid fuel generation dominate its carbon dioxide emissions. The proportion would drop slightly from 85 % in 2014 to 79 % in 2030 and be replaced by a growing proportion of emissions from gas-fired production.

- The significant decrease in energy production from solid fuels in NEB would see an accompanying reduction in the proportions (and absolute values) of carbon dioxide emissions from coal power. Carbon dioxide emissions from solid fuel plants would drop from 77 % in 2014 to 54 % in 2030. In its place, there would be a growing share of emissions from gas plants, increasing from 22 % in 2014 to 46 % in 2030.

- SSEE would experience a trend in carbon dioxide emissions from the power sector similar to that of NEB. The emissions from solid fuel plants would steadily decline in proportion, from 59 % (2014) to 52 % (2030), but remain steady in terms of absolute output. Their place would be taken by an increasing proportion of emissions from gas plants, as well as a spike in emissions from oil-fired plants in 2020, accounting for 3 % of all estimated emissions.

An assessment of the estimated regional and EU carbon intensities is presented in Section 4.3 and compared with the carbon intensity levels in the Energy Roadmap 2050 scenarios.

Figure 3.13 Regional carbon dioxide emissions profiles (REV pathway)



Note: Bottom-up results shown for EU-28.

Source: EEA (based on LCP-EPRTR database and own calculations).

4 A comparison of the bottom-up profiles with key Energy Roadmap 2050 scenarios

This chapter assesses the hypothetical medium-term evolution of the fossil fuel power sector by comparing the bottom-up findings with the (**adjusted**) top-down Energy Roadmap 2050 scenarios introduced in Section 1.3.3 ([36]). Firstly, the illustrative evolution of the power sector is presented, in terms of installed capacity, energy generation and carbon dioxide emissions in the short (2020) and medium term (2030). Then, these parameters are compared with the cost-effective levels from the Energy Roadmap 2050. This second step is intended to identify the potential risks of technological and carbon lock-in should the hypothetical bottom-up pathways be followed.

Despite possible differences in the methodologies between the bottom-up analysis and the three top-down scenarios, there is significant correlation between them:

- All profiles show a decreasing reliance on all conventional fossil fuel types, although this fact is heavily reliant on the accuracy of the construction and decommissioning profiles beyond 2015 that are available in the Platts (2014) database.

- The analysis shows a considerable risk of fossil fuel capacity lock-in from 2020 onwards, should the extended lifetimes be realised. Under those circumstances, by 2030 all regions would have excessive fossil fuel capacity, amounting to between 56 and 69 GWe, depending on the profile followed — and assuming that the development of renewable energy capacity follows the cost-effective levels from the Energy Roadmap 2050 scenarios. This fossil fuel overcapacity could translate into higher costs for decarbonising Europe's power sector by locking it in to a dependence on a high-carbon infrastructure that could hinder the effective functioning of the single EU electricity market, while simultaneously exposing owners and shareholders to the financial risk of closures (potentially stranded assets).

- Expressed in terms of 200 MWe units, the fossil fuel overcapacity by 2030 would be equivalent to 190–240 gas-fired units and around 110–150 coal-fired units. In terms of oil-fired capacity, there would, however, be scope for some 25–45 additional units.

4.1 Evolution of the fossil fuel power sector

This section presents the hypothetical evolution of the fossil fuel power sector in the short and medium term, and it compares the bottom-up findings with the top-down Energy Roadmap 2050 scenarios.

4.1.1 The EU's current fossil fuel power sector, 2014/2015

In 2014, the operational units across the EU-27 amounted to a capacity of 309 GWe (307 GWe using revised decommissioning trends and Member States' feedback), as follows:

- Almost half of the assessed fossil fuel capacity was firing solid fuels (48 %). Solid fuel-fired units were responsible for 69 % of electricity generation and about 80 % of total fossil fuel-derived carbon dioxide emissions, indicating the high load factors and carbon intensities of solid fuel-fired units.

- Gas-fired units accounted for 44 % of the operational capacity, 30 % of the energy generation and 20 % of the carbon dioxide emissions.

- Oil-fired units, on the other hand, were responsible for around 8 % of the operational capacity, but accounted for around 1–2 % of the electricity generation and carbon dioxide emissions.

The illustrative results calculated in the bottom-up analysis differ from the top-down Roadmap scenario

([36]) At the EU level, excluding Croatia, in order to be coherent with the scope of the Energy Roadmap, and for the four regional aggregations proposed for the assessment.

data (for 2015) in terms of their relative proportions of gas and solid fuels, with the three Roadmap scenarios all having a 51 % share of gas and a 39 % share of solid fuels in installed capacity. This contrast with the illustrative bottom-up profiles suggests that there is already a need to move towards reduced reliance on solid fuel-fired capacity.

The electricity generation and carbon dioxide emissions from the Roadmap scenarios tell a similar story — decreased reliance on coal-fired electricity production, with associated declines in relative carbon dioxide emissions. The adjusted Roadmap scenarios allow easier comparison with the scope of the current assessment.

4.1.2 The EU's fossil fuel power sector in 2020

By 2020, the installed capacity in the bottom-up analysis, according to the chosen lifetime assumptions, would range between 264 GWe (AVG profile) and 333 GWe (EXP profile), with the net increase in installed capacity due to planned gas-fired capacity expansion between 2015 and 2020 ([37]). However, both coal- and oil-fired capacity would decrease slightly. Thus, by 2020:

- Gas-fired capacity would account for around 52 % of the installed fossil fuel capacity and 38 % of fossil fuel electricity generation.
- Solid fuel-fired units would account for 42–43 % of the fossil fuel capacity and 61 % of the electricity generation.
- The proportion of oil-fired capacity would decrease to around 5 % of the fossil fuel capacity, again with very small shares in terms of electricity generation and emissions.

For comparison, the (adjusted) Roadmap scenarios expect fossil fuel capacity to be between 282 GWe and 285 GWe. The higher values from the bottom-up assessment (corresponding to the EXT and REV profiles) are worrying figures from the point of view of the potential risk of path dependency and ensuing carbon lock-in. They indicate a hypothetical 2020 commitment in terms of carbon infrastructure of around 50 GWe above the Roadmap scenarios, with implications for the efficient running of the integrated EU power sector.

The proportion of gas-fired capacity would remain lower in the bottom-up profiles (except for AVG), although the initial difference would decrease slightly, as shown in Figure 4.1. The extended and revised bottom-up profiles would remain quite similar, with the biggest change being a drop in oil-fired capacity in the revised profile. The profile with average historic lifetimes (AVG) presents the most changes, with lower installed capacity for all fuel types, due to the earlier decommissioning of units.

Concerning energy generation, the Energy Roadmap 2050 scenarios and the profiles in the bottom-up analysis show comparable results for 2020 (Figure 4.2). Energy generation in the bottom-up assessment ranges from 800 TWh (AVG profile) to 1018 TWh (EXT profile), while in the Roadmap scenarios it ranges between 1 185 TWh and 1 218 TWh ([38]):

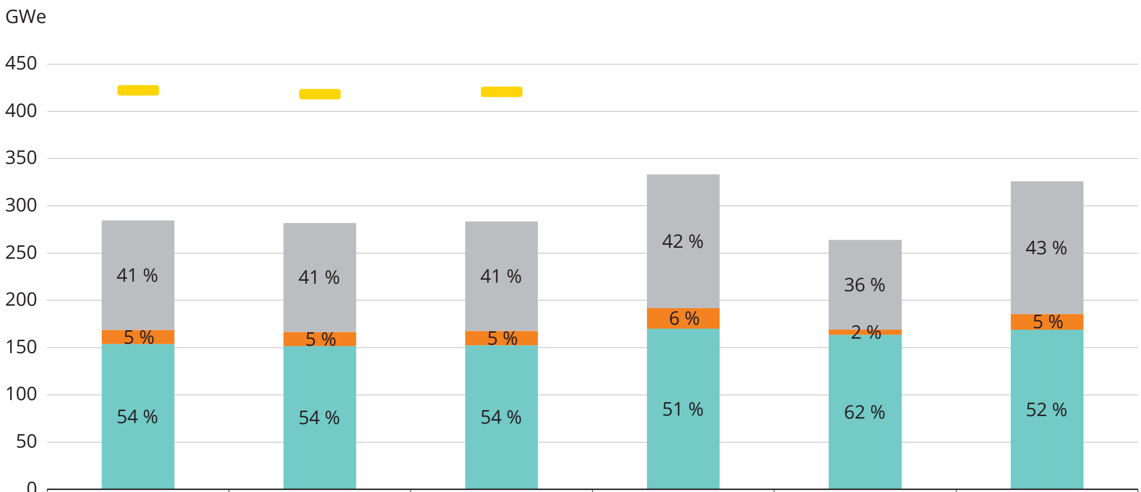
- As in 2015, the share of power generated from gas-fired capacity in the bottom-up assessment would be considerably lower than in the Roadmap scenarios.
- In turn, the proportion of power generation from solid fuel-based capacity would increase, although in absolute terms it would remain similar to the levels in the Roadmap scenarios.
- Generation from oil would decrease in the bottom-up assessments by a greater ratio than capacity, which indicates a lower load factor for liquid fuels.

A sensitivity analysis for power generation based on the applied load factors is presented in Annex 1.

Carbon dioxide emissions are also relatively closely aligned in the bottom-up assessments and in the top-down scenarios ([39]).

([37]) With Croatia included, the operational fossil fuel capacity in the bottom-up assessment ranges between 328 and 336 GWe.
([38]) After excluding 10 % generation, due to small-scale units (see Box 1.3).
([39]) The IPCC 2006 default emission factors for stationary combustion in the energy industries were used, as presented in the IPCC (2006) *Guidelines for National Greenhouse Gas Inventories.*

Figure 4.1 **Comparison of 2020 installed capacity across the Roadmap scenarios and bottom-up profiles in the EU-27 (GWe), by fuel type**

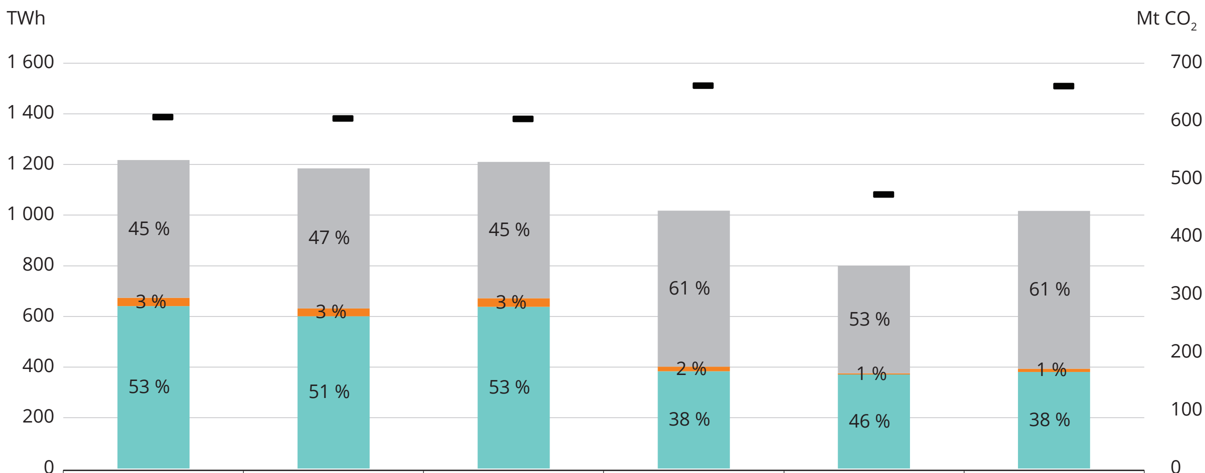


	DST adj	EE adj	RES adj	EXT	AVG	REV
Solid	116	115	116	142	95	141
Oil	15	15	15	22	5	17
Gas	154	152	153	170	164	169
Non-adjusted top-down	422	418	421	N/A	N/A	N/A

Note: The adjustment made to the Roadmap scenarios uses the adjustment factors presented in Box 1.3 to make them comparable to the bottom-up profiles. To be consistent with the Energy Roadmap 2050, Croatia is excluded from the bottom-up assessment. DST, Diversified supply technologies. EE, High energy efficiency. RES, High renewable energy sources (see Box 1.4 for a summary of the selected Energy Roadmap 2050 scenarios).

Source: EEA (based on Platts, 2014; EC, 2011c; and own calculations).

Figure 4.2 **Comparison of 2020 power generation and carbon dioxide emissions (TWh/Mt CO_2) across Roadmap scenarios and bottom-up profiles in the EU-27, by fuel type**



	DST adj	EE adj	RES adj	EXT	AVG	REV
Solid	544	553	539	616	425	623
Oil	33	31	33	18	4	12
Gas	641	601	638	384	371	381
CO_2 (Mt)	607	604	604	661	473	660

Note: The adjustment made to the Roadmap scenarios uses the adjustment factors presented in Box 1.3 to make them comparable to the bottom-up profiles. To be consistent with the Energy Roadmap 2050, Croatia is excluded from the bottom-up assessment. Energy Roadmap 2050 scenarios (DST, EE and RES) are presented in Box 1.4.

Source: EEA (based on Platts, 2014; EC, 2011c; and own calculations).

4.1.3 The EU's power sector in 2030

The development of the power mix in 2030, as modelled in the Energy Roadmap 2050, is illustrated in Figure 4.3 and compared with the bottom-up assessment. Concerning the (adjusted) Roadmap scenarios, the installed fossil fuel capacity would range from 235 GWe to 245 GWe in 2030. In all Roadmap scenarios most of the installed capacity is renewable, totalling 54–60 % of the entire installed capacity. Gas-fired units also make a significant contribution to the fossil fuel capacity.

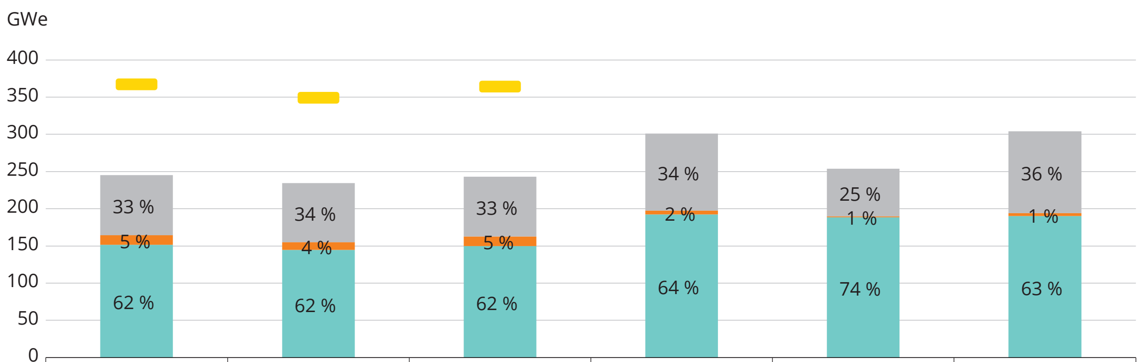
By 2030, the installed fossil fuel capacity, according to the bottom-up analysis, would range between 254 and 304 GWe ([40]), showing a slight decrease compared with 2020. Therefore, the bottom-up assessment would exceed the cost-effective scenario levels by up to 69 GWe in 2030 — or 345 fossil fuel units, each of 200 MWe capacity — potentially unbalancing the single EU electricity market and strengthening the path dependency generated by this capacity.

The additional capacity would be mostly gas-fired units, but also some solid fuel-based capacity (for the EXT and REV profiles). Liquid fuel capacity would be significantly lower in the bottom-up profiles.

The REV and EXT profiles are generally in line with gas-and oil-fired capacity, but the REV profile would result in an additional 7 GWe of inflexible, carbon-intensive solid fuel-fired capacity in 2030. This could be problematic for the power sector, considering not only the imperative to cut GHG emissions but also the growing need for flexible energy generation that can accommodate the growing proportion of power generated from variable renewable sources. The AVG profile, on the other hand, accounts for only around 60 % of the solid fuel-fired capacity when compared with the REV or EXT profiles.

According to the bottom-up profiles, a huge amount of the fossil fuel capacity currently in operation (around 200 GWe) would remain until 2030. Such a commitment to fossil fuel power plants in future decades — if realised — would constitute a significant infrastructural lock-in. As the currently planned fossil fuel capacity corresponds to over one quarter of the large-scale fossil fuel capacity in 2014 (29 %, or 88.5 GWe), reconsidering some of these planned investments in new capacity and in technological upgrades would play an important role in facilitating Europe's goal of integrating and decarbonising its electricity market.

Figure 4.3 Comparison of 2030 installed capacity across the Roadmap scenarios and bottom-up profiles in the EU-27 (GWe), by fuel type



	DST adj	EE adj	RES adj	EXT	AVG	REV
Solid	81	80	81	103	64	110
Oil	13	10	13	5	1	4
Gas	152	145	150	192	189	190
Non-adjusted top-down	367	349	364	N/A	N/A	N/A

Note: The adjustment made to the Roadmap scenarios uses the adjustment factors presented in Box 1.3 to make them comparable to the bottom-up profiles. To be consistent with the Energy Roadmap 2050, Croatia is excluded from the bottom-up assessment. Energy Roadmap 2050 scenarios (DST, EE and RES) are presented in Box 1.4.

Source: EEA (based on Platts, 2014; EC, 2011c; and own calculations).

([40]) Excluding Croatia, in order to be in line with the scope of the Energy Roadmap 2050.

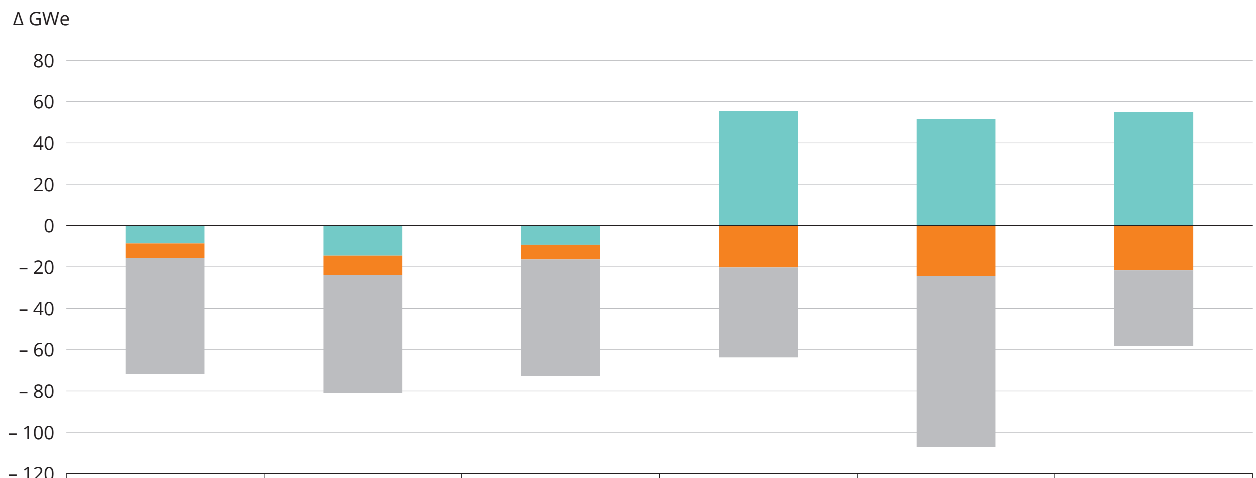
Figure 4.4 compares the bottom-up decommissioning profiles with the projected ranges in installed capacity in the cost-effective Energy Roadmap 2050 scenarios. It shows the net increase (or decrease) in installed capacity by type of fuel and scenario. The three Roadmap scenarios follow similar patterns: net decreases in oil-, solid fuel- and gas-fired capacity. However, the bottom-up profiles (in all three lifetime variants) show a net increase in gas-fired capacity between 2015 and 2030, ranging from 52 to 55 GWe, while the (adjusted) Roadmap scenarios show a decrease of between 9 and 14 GWe. The increase in gas-fired capacity in the bottom-up analysis might be explained by the inclusion of small-capacity plants in the top-down scenarios, as well as perhaps the absorption of different projected gas market conditions that have an impact on these gas plants in the modelling for the Roadmap. The net decrease in oil-fired capacity is consistent across all illustrative profiles, ranging between 7 and 24 GWe. The net decrease in solid fuel fired capacity is consistent across all profiles, ranging between 37 and 83 GWe.

Regarding energy generation, by 2030 the illustrative bottom-up assessments result in 717 TWh (AVG profile) and 931 TWh (REV profile) for the EU-27, while the (adjusted) Energy Roadmap 2050 scenarios project between 766 and 888 TWh of electricity production. The overproduction in the bottom-up assessment reaches up to 165 TWh.

The bottom-up analysis finds a greater proportion of electricity production from solid fuels, especially in the EXT and REV profiles for 2030 (51–53 %), while the Energy Roadmap solid fuel generation represents 24–30 % of the electricity generated from fossil fuels in 2030. This is in contrast to the relatively similar shares in capacity, probably owing to higher load factors in the analysis performed under this study.

Carbon dioxide emissions are significantly higher in 2030 in the bottom-up sectoral EXT and REV profiles compared with the (adjusted) Roadmap scenarios (Figure 4.5). The higher energy production in the present analysis explains this increase.

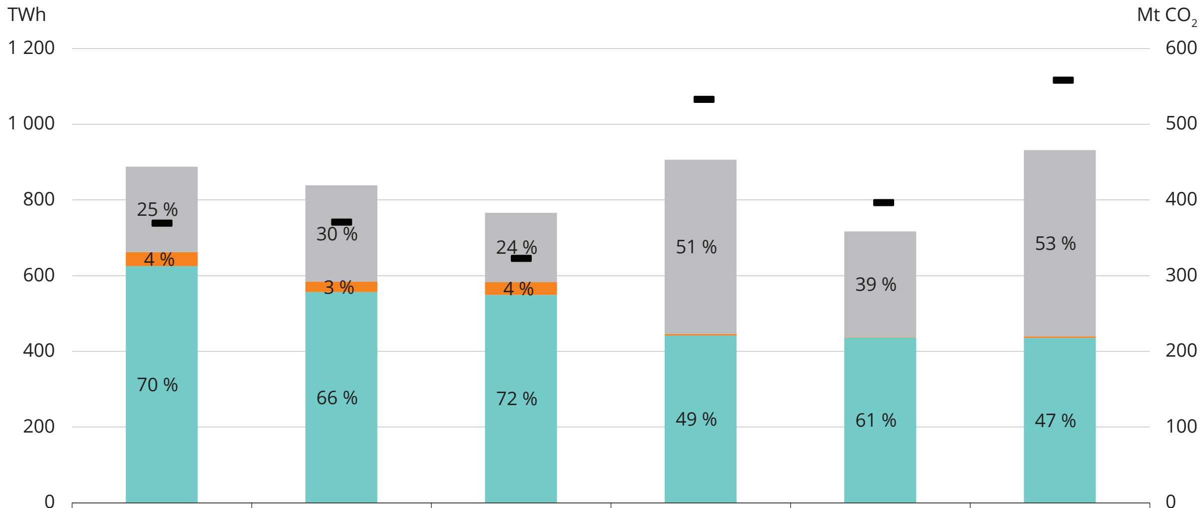
Figure 4.4 Capacity change from 2015 to 2030 by fuel type and scenario in the EU-27 (Δ GWe)



	DST adj	EE adj	RES adj	EXT	AVG	REV
Solid	– 56	– 57	– 56	– 43	– 83	– 37
Oil	– 7	– 9	– 7	– 20	– 24	– 22
Gas	– 9	– 14	– 9	55	52	55

Source: EEA (based on Platts, 2014; EC, 2011c; and own calculations).

Figure 4.5 **Comparison of 2030 power generation and carbon dioxide emissions (TWh/Mt CO_2) across Roadmap scenarios and bottom-up profiles in the EU-27, by fuel type**



	DST adj	EE adj	RES adj	EXT	AVG	REV
Solid	226	255	184	460	279	492
Oil	37	27	33	4	1	4
Gas	625	556	549	442	437	435
CO_2 (Mt)	369	371	323	533	394	558

Source: EEA (based on Platts, 2014; EC, 2011c; and own calculations).

4.2 Risk of carbon lock-in and stranded assets

The concept of 'lock-in' has been extensively used to study the effects of path dependencies and reinforcing effects in the context of transition studies. With regard to the energy system carbon lock-in refers to the self-perpetuating inertia created by large fossil fuel-based energy infrastructure that inhibits public and private efforts to introduce alternative energy technologies (Klitkou, 2015; Frantzeskaki and Loorbach, 2010; Unruh, 2000). This section aims to assess to what extent the EU energy system relies on a large fossil fuel-based capacity and how this would evolve up to 2030 in accordance with the illustrative lifetime assumptions chosen for the study. In order to assess the risk of carbon lock-in, the bottom-up findings are compared with the trends in the Energy Roadmap 2050, which deliver a 40 % reduction in emissions from the energy sector by 2030. Given the small variation between the Roadmap scenarios, one value is presented when the three scenarios converge and a range is given when there are differences.

4.2.1 The EU picture

Table 4.1 shows the installed capacities for both the top-down (Roadmap) and bottom-up data for 2014/2015, 2020 and 2030. It shows the range for the (adjusted) Energy Roadmap 2050 scenarios, as well as the values from the bottom-up assessment, considering only the extended technical lifetimes (EXT) and their revision (REV) taking into account the requirement to reduce air pollutant emissions under the IED. Excessive capacity by 2030 is calculated as the installed capacity according to bottom-up profiles **minus** the adjusted Roadmap values.

- As described above, realising the longer lifetimes is incompatible with EU decorbonisation objectives: it results in a considerable risk of carbon lock-in from 2020 onwards, as the installed fossil fuel capacity corresponding to the bottom-up profiles is already 41–51 GWe higher than that expected from the Energy Roadmap 2050.

- By 2030, this increases to between 56 and 69 GWe of overcapacity, depending on the profile and Roadmap scenario, as renewable energy capacity in the Roadmap is expected to increase. This excessive fossil fuel capacity is equivalent to between 278 and 347 units of 200 MWe each, or the equivalent of roughly 20 % of the operational fossil fuel capacity in 2030.

A similar analysis is shown by fuel type in Table 4.2. The adjusted Roadmap information reflects the different shares used by fuel type. All fuels present potential stranded assets at some point. The overcapacity by 2030 translates into 190–240 gas-fired units, and

Table 4.1 Evolution of installed capacity in the EU-27 (GWe)

Region	Adjusted Energy Roadmap scenarios			EXT (REV)			Excess capacity
	2015	2020	2030	2014	2020	2030	2030
EU-27	315–317	282–285	235–245	309 (307)	333 (326)	301 (304)	56–66 (59–69)

Note:
- Bottom-up capacity > top-down adjusted capacity
- Bottom-up capacity < top-down adjusted capacity

Excess capacity is calculated as the difference between the bottom-up calculated capacity and the capacity range from the selected Energy Roadmap 2050 scenarios (differences due to rounding).

Source: EEA (based on EC, 2011c; Platts, 2014; the LCP-EPRTR and ETS databases and own calculations).

around 110–150 solid fuel-fired units of 200 MWe each. For oil-fired units, there would be scope for an additional 25–45 units, each of 200 MWe capacity.

4.2.2 The regional picture

In absolute terms, the greatest risk of fossil fuel lock-in in 2030 is in SSEE (Table 4.3 and Figure 4.6), where the excessive capacity would range between 22 and 26 GWe in the illustrative lifetime profiles — the equivalent of 113–130 fossil fuel units of 200 MWe each — and in NEB, where the excessive fossil fuel capacity would range between 16 and 25 GWe, or 84–126 fossil fuel units with a nominal capacity of 200 MWe each. In relative terms, however, NEB has a considerably greater risk of lock-in than the other regions when the regional bottom-up profile is compared with the cost-effective capacity levels in the Energy Roadmap 2050.

Although they vary in terms of technology and installed capacity, natural gas generation systems are generally more flexible to operate than other thermal technologies. With renewable electricity generation on the rise stimulated by the 2020 and 2030 EU climate

Table 4.2 Installed capacity by fuel type in the EU-27 (GWe)

Fossil Fuel	Adjusted Energy Roadmap scenarios			EXT (REV)			Excess capacity
	2015	2020	2030	2014	2020	2030	2030
Gas	159–160	152–154	145–152	137 (135)	170 (169)	192 (190)	41–48 (38–46)
Oil	20	15	10–13	26 (26)	22 (17)	5 (4)	– 7 to – 5 (– 9 to – 6)
Solid fuel	137	115–116	80–81	147 (146)	142 (141)	103 (110)	22–24 (29–30)
Total	**315–317**	**282–285**	**235–245**	**309 (307)**	**333 (326)**	**301 (304)**	**56–66 (59–69)**

Note:
- Bottom-up capacity > top-down adjusted capacity
- Bottom-up capacity < top-down adjusted capacity

Excess capacity is calculated as the difference between the bottom-up calculated capacity and the capacity range from the selected Energy Roadmap 2050 scenarios (differences due to rounding).

Source: EEA (based on EC, 2011c; Platts, 2014; the LCP-EPRTR and ETS databases and own calculations).

Table 4.3 Evolution of installed regional capacity * (GWe)

Region	Adjusted Energy Roadmap scenarios			EXT (REV)			Excess capacity
	2015	2020	2030	2014	2020	2030	2030
CEE	51	46–47	36	38	50	42	6
				(38)	(47)	(43)	(7)
CWE	105–106	95–96	75–83	103	107	91	8–16
				(101)	(101)	(88)	(5–13)
NEB	68	54–55	45–47	67	66	63	16–18
				(67)	(70)	(70)	(23–25)
SSEE	92	86	79–80	102	110	105	25–26
				(102)	(108)	(102)	(22–23)

Note:
- Bottom-up capacity > top-down adjusted capacity
- Bottom-up capacity < top-down adjusted capacity
- Bottom-up capacity overlaps with top-down adjusted capacity

Excess capacity is calculated as the difference between the bottom-up calculated capacity and the capacity range from the selected Energy Roadmap 2050 scenarios (differences due to rounding).

* Croatia is not included.

Source: EEA (based on EC, 2011c; Platts, 2014; the LCP-EPRTR and ETS databases and own calculations).

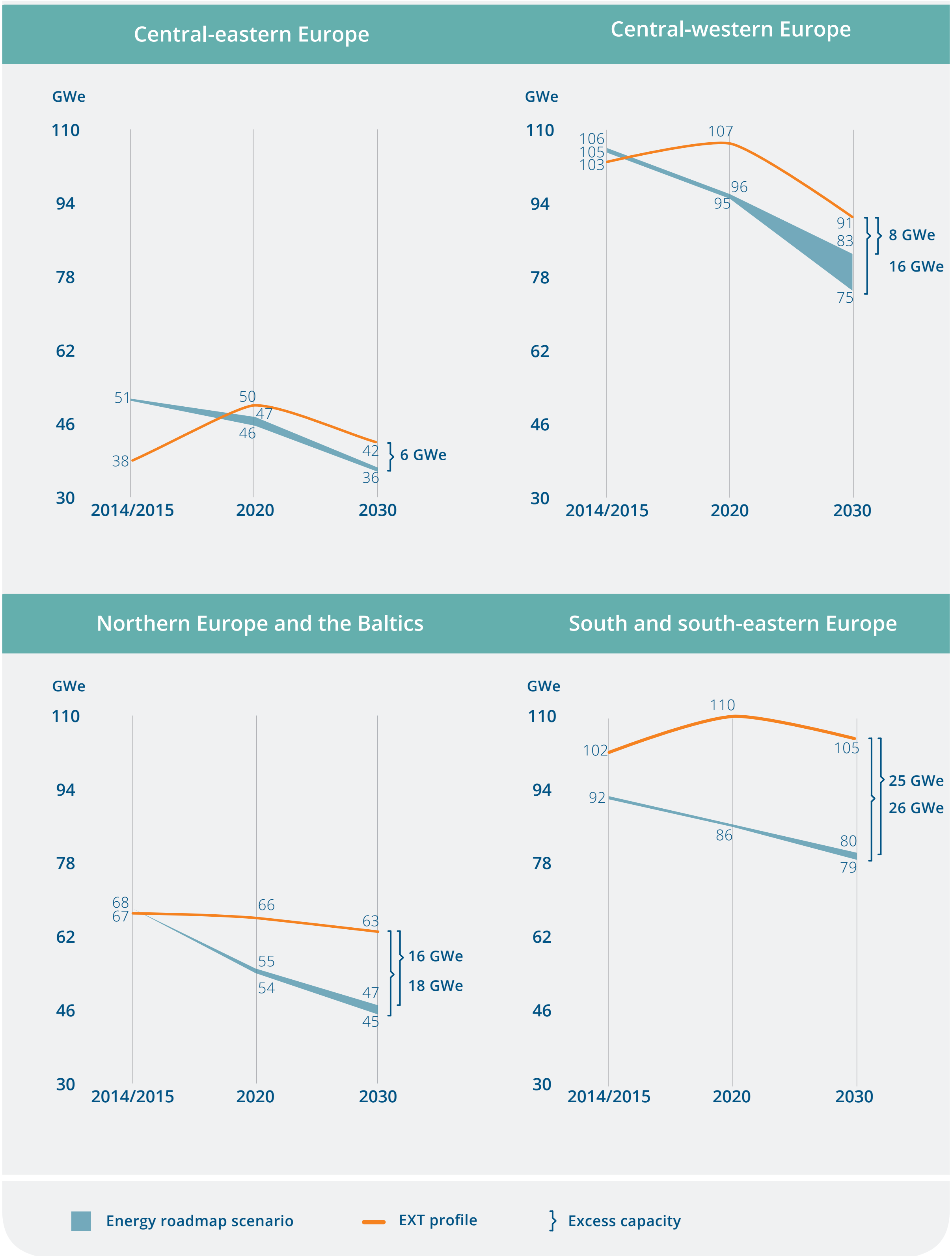
and energy targets, natural gas-fired power generation is better suited than coal-fired generation to support the integration of fluctuating amounts of power from variable renewable energy sources (wind power and solar PV) into the electricity grid, and could facilitate a greater proportion of intermittent renewable electricity generation. In addition, natural gas-based generation is roughly half as carbon-intensive as coal-based generation. For these reasons, it is important to take a closer look at the excess capacity by specific fossil fuel type, as summed up in Table 4.4.

The current EEA analysis shows that, by 2030, the greatest risk of a coal-based capacity lock-in, in absolute terms and in relation to the illustrative assumptions made, would be in CWE (18 GWe, or roughly 65 % excess capacity compared with the cost-effective Roadmap levels), followed by NEB (7 GWe, or about 84 % higher than the cost-effective levels) — levels considerably higher than desired, which could hamper the potential to balance out the higher anticipated levels of intermittent renewable power generation. The risk of a coal-based capacity lock-in is smaller in SSEE and CEE (2–3 GWe, or roughly 10 % above the cost-effective Roadmap levels). In SSEE, this is because only a few new coal-fired capacity additions are planned (+ 3 GWe). In CEE, it is because a large share of the old capacity is expected to have been decommissioned by 2030.

It is worth noting that, for NEB, the risk of stranded coal-based capacity is fully associated with the anticipated technological upgrading to reduce emissions of air pollutants in accordance with the IED. The same level of technological upgrading would result in only a minor increase in potentially stranded coal-based capacity in CEE (+ 2 GWe, due to a larger proportion of ageing solid fuel-fired capacity in the region leading, overall, to more decommissioning), whereas in CWE and in SSEE it would lead to a slight decrease in excess coal-based capacity compared with the units being decommissioned in line with their extended technical lifetimes, as more capacity would be decommissioned than retrofitted to meet the IED ELVs.

As for capacity, a comparison of the cost-effective carbon dioxide emission levels in the Energy Roadmap 2050 scenarios and those resulting from the illustrative bottom-up profiles is summarised in Table 4.5.

Figure 4.6 **Illustrative regional fossil fuel capacity profiles (EXT) and cost-effective capacity levels (Energy Roadmap 2050)**



Source: EEA (based on EC, 2011c; Platts, 2014; the LCP-EPRTR and ETS databases and own calculations).

Box 4.1 Representation of illustrative over- and undercapacity by 2030

The comparison of cost-effective fossil fuel capacity ranges by 2030 according to the Energy Roadmap 2050, with the values obtained from the bottom-up assessment (considering only the extended technical lifetimes (EXT) and their revisions (REV) taking into account the requirement to reduce air pollutant emissions under the IED) illustrate the relative risk of a future fossil fuel capacity lock-in, by region and by fossil fuel type, if the extended capacity lifetimes became a reality.

Table 4.4 Over- and undercapacity by fuel type, by 2030, compared with cost-effective levels (%, comparison of bottom-up with Roadmap capacity)

Region	Solid fuel-fired capacity				Gas-fired capacity				Oil-fired capacity			
	EXT		REV		EXT		REV		EXT		REV	
	(min–max)		(min–max)		(min–max)		(min–max)		(min–max)		(min–max)	
CEE	0 %	2 %	9 %	11 %	59 %	83 %	53 %	76 %	– 52 %	– 44 %	– 52 %	– 44 %
CWE	73 %	77 %	62 %	65 %	– 15 %	– 2 %	– 14 %	– 2 %	– 94 %	– 92 %	– 94 %	– 92 %
NEB	– 10 %	– 5 %	74 %	84 %	51 %	56 %	49 %	54 %	– 49 %	– 44 %	– 100 %	– 100 %
SSEE	15 %	15 %	12 %	12 %	40 %	41 %	38 %	39 %	– 22 %	– 2 %	– 34 %	– 18 %
EU-27	**28 %**	**30 %**	**36 %**	**38 %**	**27 %**	**33 %**	**25 %**	**32 %**	**– 58 %**	**– 49 %**	**– 68 %**	**– 61 %**

Note: Orange indicates an excess of capacity; green indicates a shortfall of capacity. Lighter shades illustrate a lower excess or shortfall; darker shades illustrate a higher excess or shortfall.

Source: EEA (based on EC, 2011c; Platts, 2014; the LCP-EPRTR and ETS databases and own calculations).

Photo: © Brett Lamb (www.istockphoto.com)

4.2.3 Required pace of change

Given that economic sectors are inherently linked, the pace of decarbonisation in the power sector has implications in terms of cost-effectiveness for the ability of other sectors to reduce their GHG emissions by 2050.

The levels of fossil fuel capacity decommissioning that the EU needs to achieve by 2030 to meet the Roadmap levels are equivalent to a 20–24 % reduction in all fossil fuel capacity installed across the EU. For coal-fired capacity, they are equivalent to a 45 % reduction in the installed capacity. In contrast, gas-fired capacity could increase by 6–11 % of the capacity installed in 2014.

Accordingly, between now and 2030 the EU needs to sustain an annual reduction in its fossil fuel capacity of between 1.7 % and 2.0 % to be in line with the Energy Roadmap 2050 decarbonisation levels. In contrast to this, in the absence of further incentives, such as a meaningful carbon price signal, it would realise an annual decrease of only 0.4–0.5 % if the currently operational and planned units continued to operate until the end of their expected, longer, lifetimes. If it materialises, by 2050, this inertia in the power sector will have had considerable knock-on effects on the cost of reducing GHG emissions in the transport, residential and industrial sectors too.

4.3 Assessment of fossil fuel carbon intensities

This section provides a regional comparison of the cost-effective carbon intensities (CIs) for fossil fuel-based electricity generation in the Roadmap scenarios and in the bottom-up profiles, by fuel type, region and year.

Table 4.6 compares the average carbon intensities by region obtained from the bottom-up revised

Table 4.5 Illustrative carbon dioxide emissions in the EU-27 and regions (Mt CO_2)

Region	Adjusted Energy Roadmap scenarios			EXT (REV)		
	2015	2020	2030	2014	2020	2030
CEE	160–164	135–139	91–109	86 (86)	134 (125)	109 (114)
CWE	279–290	223–232	110–139	210 (208)	247 (233)	189 (181)
NEB	168–172	90–98	45–51	152 (152)	113 (137)	87 (121)
SSEE	198–201	144–147	72–81	126 (126)	167 (166)	149 (142)
EU-27	**810–823**	**604–607**	**323–371**	**574 (572)**	**661 (660)**	**533 (558)**

Note:
- Bottom-up emissions > top-down adjusted emissions
- Bottom-up emissions < top-down adjusted emissions

Small differences due to rounding.

Source: EEA (based on EC, 2011c; Platts, 2014; the LCP-EPRTR and ETS databases and own calculations).

Table 4.6 Carbon intensity (CI) by fuel type in 2014 (REV profile) and in 2015 (Roadmap) (kt CO_2/GWh)

Region	REV				Adjusted Energy Roadmap scenarios
	Gas	Oil	Solid fuel	All fossil fuels	Average, all fossil fuels
CEE	0.384	0.754	0.570	0.564	0.639
CWE	0.464	0.724	0.649	0.617	0.549
NEB	0.414	0.552	0.934	0.727	0.568
SSEE	0.325	0.754	0.608	0.462	0.461
CI per fuel	**0.380**	**0.718**	**0.677**	–	–
EU-27	–	–	–	**0.589**	**0.543**

Source: EEA (based on EC, 2011c; Platts, 2014; the LCP-EPRTR and ETS databases and own calculations).

(REV) profile, with the average carbon intensities for these regions calculated from the Roadmap scenarios. The regional carbon intensities differ slightly between the bottom-up profile and the top-down scenarios. However, in both sets, SSEE has the lowest carbon intensity owing to its higher proportion of gas-fired capacity.

Table 4.7 shows the carbon intensities for fossil fuels (based on the IPCC emission factors and power plant efficiencies) by type of fuel. These values, together with the reported ETS 2012 emissions, were used to calculate the energy output of each power plant. For new and planned plants, the capacity and load factors were used to estimate the energy output per plant (see the sensitivity analysis in Annex 1), and then these carbon intensities (based on the IPCC emission factors and power plant efficiencies by type of fuel) were used to calculate the carbon dioxide emissions.

Table 4.8 presents a regional comparison of fossil fuel carbon intensities for the Energy Roadmap 2050 scenarios and the bottom-up calculations for 2015, 2020 and 2030.

According to the bottom-up illustrative profiles, NEB had the highest carbon intensity in all years assessed, followed by CWE, CEE and, lastly, SSEE. The cost-effective carbon intensities in the Roadmap scenarios varied less by region, from 0.33 kt CO_2/GWh (SSEE, 2030) to 0.64 kt CO_2/GWh (CEE, 2015). The lowest carbon intensity from the bottom-up assessment was 0.49 kt CO_2/GWh, in NEB in 2030, while the highest was 0.73 kt CO_2/GWh, also for NEB, but in 2014.

There was little variation between the two bottom-up assessments, the biggest difference occurring in NEB in 2030, due to the greater number of solid fuel plants remaining in operation with revised years of decommissioning.

Table 4.7 Carbon intensities by fuel type

Fuel/technology	Carbon intensity (kt CO_2/GWh)
Bituminous and other coal	0.973
Lignite coal	1.039
Gas/gas turbine	0.577
Gas/combined cycle	0.367
Oil	0.480
Shale	1.101

Source: EEA (based on IPCC emission factors; Platts, 2014; the LCP-EPRTR and ETS databases and own calculations).

Table 4.8 Carbon intensity in the EU-27 and regions (kt CO_2/GWh)

Region	Adjusted Energy Roadmap scenarios			EXT (REV)		
	2015	2020	2030	2014	2020	2030
CEE	0.64	0.59–0.61	0.58–0.59	0.564 (0.564)	0.694 (0.674)	0.668 (0.672)
CWE	0.55	0.53	0.42–0.46	0.617 (0.617)	0.665 (0.655)	0.601 (0.591)
NEB	0.57	0.45–0.49	0.36–0.39	0.726 (0.727)	0.588 (0.632)	0.489 (0.571)
SSEE	0.46	0.42	0.33	0.462 (0.462)	0.640 (0.639)	0.589 (0.583)
EU-27	**0.540**	**0.5–0.51**	**0.42–0.44**	**0.589 (0.589)**	**0.650 (0.650)**	**0.588 (0.599)**

Note:
- Bottom-up CI > top-down adjusted CI
- Bottom-up CI < top-down adjusted CI
- Bottom-up CI overlaps with top-down adjusted CI

Source: EEA (based on EC, 2011c; Platts, 2014; the LCP-EPRTR and ETS databases and own calculations).

4.4 Conclusions

The EU climate and energy policy objectives require the transition towards a low-carbon society by 2050, starting with the fundamental transformation of the electricity sector. It was the aim of this assessment to provide a sound basis for comparing the desired evolution in the power sector that would be consistent with the EU's decarbonisation objectives, with the potential bottom-up evolution of the power sector under certain illustrative lifetime considerations. With that in mind, the purpose was to highlight the importance of a rational and progressive decommissioning of fossil fuel capacity across the EU electricity sector, and certainly not to forecast the actual future evolution of fossil fuel capacity in the sector.

A number of overarching considerations can be summed up from this exercise.

With respect to installed capacity, each of the four regions analysed would experience a net fossil fuel overcapacity in the bottom-up hypothetical profiles for 2030, if the extended lifetimes were to become reality. The only case of less bottom-up capacity compared with the Energy Roadmap 2050 scenarios was observed for CEE, but for the current years 2014/2015 (– 21 %).

In total, the illustrative profiles identify a risk of excess capacity across the EU in the range of 56–69 GWe by 2030, primarily in the form of gas-fired capacity (38–48 GWe, or more than 200 gas-fired units, each of 200 MWe) and coal-fired capacity (22–30 GWe, equivalent to roughly 150 coal-fired units, each of 200 MWe in size). Only oil-fired capacity would be lower in the bottom-up analysis than in the cost-effective Roadmap scenarios. From a regional perspective, CEE is expected to have the lowest risk of stranded assets (5–8 GWe), while SSEE is expected to run the highest risk (23–26 GWe).

The 56–69 GWe of EU fossil fuel capacity in excess of the cost-effective Roadmap levels relative to the year 2030, if realised, would represent a significant risk of path dependency and carbon lock-in, limiting the EU's and individual Member States' ability to achieve related energy market and climate goals cost-effectively. Constituting up to 30 % more capacity than that required in the Energy Roadmap 2050, this hypothetical overcapacity — running the risk of becoming stranded — calls for a careful consideration of investment decisions and technological upgrading plans in the run up to 2020.

This report recognises that the power sector infrastructure is long lived and resilient to change, that new investment cycles in the sector can take decades to materialise and that the ensuing consequences are equally long lasting. Similar to other recent publications (Oberthur and Dupont, 2015), it suggests that there is a growing need for both private and public sector organisations to apply clear thinking to long-term planning, in order to avoid uncoordinated and more costly responses to the pressing decarbonisation challenges that we face.

An earnest reflection on how the EU power sector needs to evolve to a qualitatively different structure in future — not only as energy from renewable sources and energy efficiency progress in line with targets, but also as fossil fuel capacity needs to decrease in line with decarbonisation objectives — will enable both operators and regulators to cope with the upcoming transition of the power sector and ongoing integration of the European energy market. Moreover, it will empower organisations to come up with successful long-term business strategies in line with the EU's climate objectives.

From a regulatory perspective, it is essential to consider the risk posed by fossil fuel overcapacity and carbon infrastructure lock-in in the ongoing revision of the ETS and with regard to national initiatives that aim to establish capacity mechanisms (i.e. potential subsidies for extending the lifetime of capacity) in the power sector.

There are effective synergies between the climate and industrial emissions policies targeting the power sector in Europe. These can, and should be, used to reinforce positive feedback loops between decarbonisation goals and health and environmental targets that aim to reduce emissions of harmful air pollutants from LCPs. Avoiding costly technological retrofits in the power sector to reduce air pollution emissions and comply with the IED would improve air quality and reduce the risk of future stranded assets, especially among the most carbon-intensive and inflexible baseload plants that are not able to support the integration of an intermittent power supply from renewable sources.

More generally, the regular collection and dissemination of information on the actual and projected evolution of fossil fuel capacity across countries could be a useful complementary tool to enhance transparency and predictability for regulators and investors and to facilitate the cost-effective integration of cross-border capacities. The ongoing discussions on governance tools under the Energy Union could, for example, lead to an agreement to provide such information as part of the integrated national energy and climate plans or the low carbon development strategies being advanced by countries.

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Annex 1 Sensitivity analysis

In this annex we seek to test the robustness of the bottom-up calculations and the resulting illustrative power sector profiles through an analysis that compares the consequences of different inputs for the outputs. Methodological choices and uncertainty are assessed by tweaking variable inputs to deliver different results and conclusions. A one-factor-at-a-time sensitivity analysis is performed by changing variable load factors and expected lifetime inputs, individually, and assessing the impact on energy generation and installed capacity outputs. Box A1.1 summarises the methodology for each load factor.

The results vary largely by variable input, although general statements can be made. Using method 1, the load factor yields significantly higher energy outputs than the more robust methods 2, 3 and 4. Using a historic average lifetime variant (AVG profile) yields lower installed capacity for each of 2014, 2020 and 2030, with differential shares in carbon dioxide emissions by region and fuel based on the relative ages of plants. Including earlier decommissioning years for nuclear power in Germany yields slight but not substantial reductions in energy output for 2020 and 2030. Including captured carbon in the carbon dioxide emissions from the PRIMES models yields slight but insignificant impacts on carbon dioxide emissions.

Load factor sensitivity

For the sensitivity analysis of load factors, four different potential methods were identified, one of which (method 4) was deemed to be the most robust and was used throughout this report.

The effects of load factor inputs on the energy outputs were analysed ([41]). Below is a presentation and analysis of the load factor sensitivity for the years 2020 and 2030. For the year 2014, the same methodologies across all methods were used, because it was preferable to use the real data available (load factors based on CO_2 outputs/CO_2 intensity, as obtained from the ETS 2012 database). As such, data for 2014 are not presented as a subsection, because the results were equal across all methods.

Load factor sensitivity for 2020

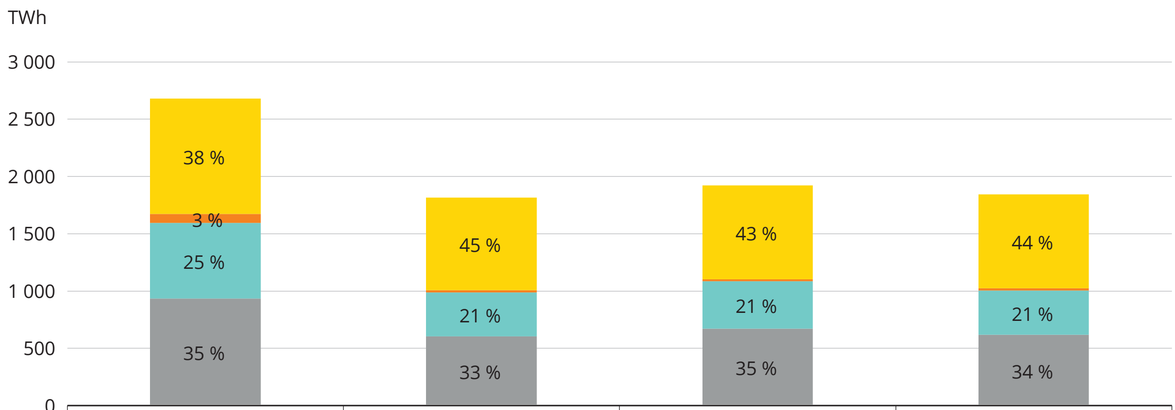
For 2020, energy production was significantly higher using method 1 than methods 2, 3 or 4 (Figure A1.1). The use of theoretical load factors in method 1 yielded higher shares of solid fuel- and gas-fired output, and lower shares of uranium-generated output, than methods 2, 3 and 4. Reflecting absolute outputs, the theoretical load factors using method 1 are higher than

Box A1.1 Four possible load factor methodologies

- **Method 1:** All plants were assigned theoretical load factors based on 'scholarly articles' by fuel type.
- **Method 2:** All plants were assigned load factors based on database averages.
- **Method 3:** Existing plants used practical load factors based on CO_2 outputs/CO_2 intensity, and new plants were assigned load factors based on database averages per fuel type.
- **Method 4:** Existing plants used practical load factors based on CO_2 outputs/CO_2 intensity, with the exception of unrealistic load factors of > 0.9, in which case existing plants were assigned load factors based on database averages. Plants with load factors of zero were excluded. New plants were assigned load factors based on database averages.

([41]) The assessment was also carried out for CO_2 emissions, but results are proportional to energy production and as such less relevant for this analysis.

Figure A1.1 Energy production in the EU-28 in 2020 (TWh)



	Method 1	Method 2	Method 3	Method 4
Uranium	1 009	810	820	820
Liquid	78	19	18	18
Gas	660	385	413	387
Solid	934	604	672	619

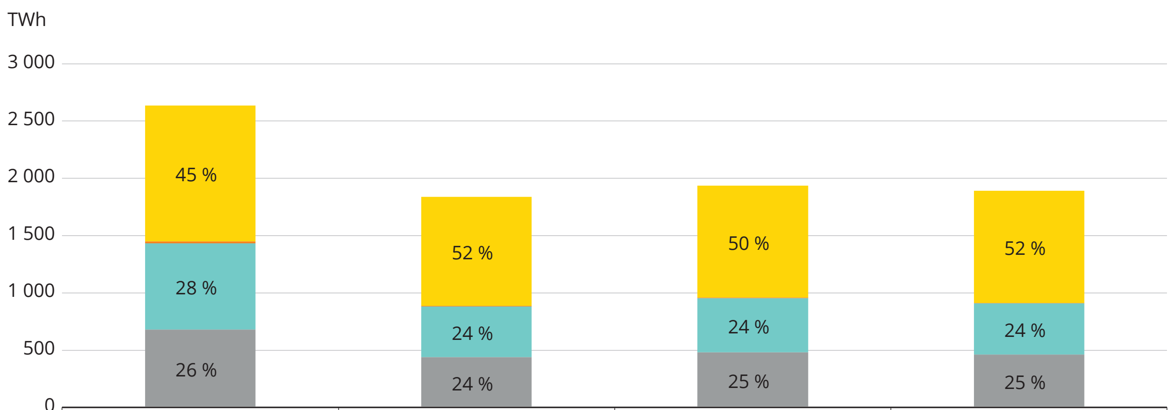
Source: EEA (based on Platts, 2014; and own calculations).

the averaged load factors used in the other methods. Choosing to keep real data for existing plants using methods 3 and 4 gave slightly higher solid fuel-, gas- and uranium-generated outputs than method 2, in which all load factors were averages. This indicates, for existing plants in 2020, slightly higher load factors for solid fuel, gas and uranium plants than the database averages. Ameliorating unrealistic load factors (> 0.9) from the pool of method 3 yielded lower gas and solid fuel energy outputs in method 4, indicating a prevalence of unrealistic load factors for plants powered by these fuel types.

Load factor sensitivity for 2030

For 2030, similar conclusions can be drawn, demonstrated by the findings in Figure A1.2. Theoretical load factors used in method 1 yielded

Figure A1.2 Energy production in the EU-28 in 2030 (TWh)



	Method 1	Method 2	Method 3	Method 4
Uranium	1 186	952	977	977
Liquid	19	5	4	4
Gas	750	442	472	446
Solid	682	441	482	463

Source: EEA (based on Platts, 2014; and own calculations).

much higher absolute energy outputs than those used in methods 2, 3 and 4. The share of solid fuel- and gas-generated outputs were higher, and the share of uranium used was lower using method 1, indicating proportionately higher theoretical load factors for gas and solid fuels, and lower load factors for uranium. Keeping real data for existing plants in 2030 using methods 3 and 4 again yielded higher gas-, solid fuel- and uranium-generated outputs than method 2. This indicated slightly higher real load factors for these plants in 2030 than database averages. As in 2020, choosing to ameliorate the unrealistic load factors from methods 3 and 4 yielded lower energy outputs for gas- and solid fuel plants.

Lifetime sensitivity

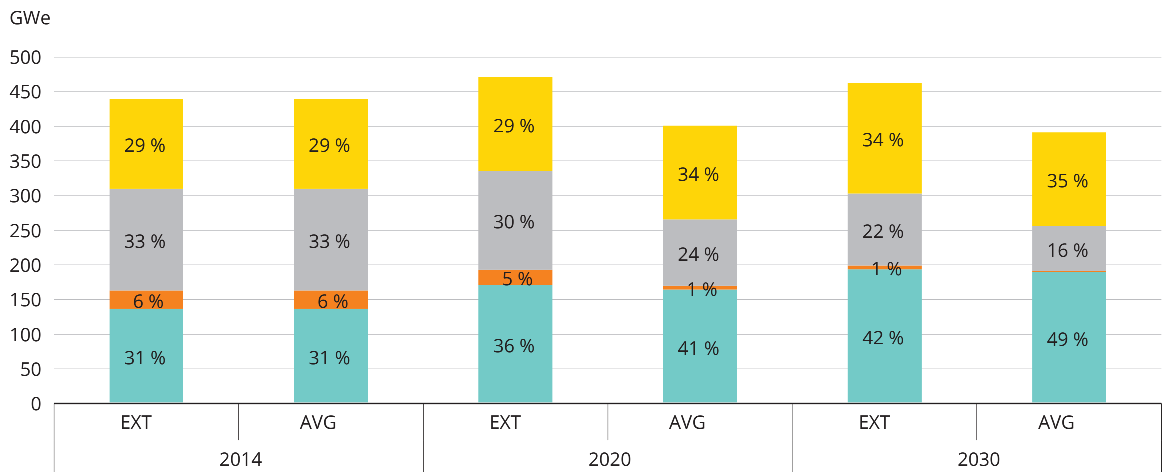
A lifetime sensitivity analysis was performed, keeping the load factor stable using method 4, focusing on capacity, in terms of output, and carbon dioxide emissions. Energy production was not included, as it would be directly proportional to capacity, given the stable load factor, and would yield the same conclusions. Due to the variable age of power plants by region, it was decided to perform the analysis on a regional basis, to yield more specific results regarding the outcome of the lifetime-based methodology. Two different methods were used — extended lifetimes variant (EXT profile, corresponding to the currently expected, longer, lifetimes) and average lifetimes variant (corresponding to the average (AVG) lifetime profile). A tertiary analysis was done, considering the outcome of using updated decommissioning paths for nuclear power plants in Germany. Table A1.1 shows the lifetimes for both variants. The findings in this report are based on the choice of extended lifetimes variant and do not include the updated decommissioning paths for nuclear power plants in Germany. This section will demonstrate the consequences of other lifetime methods.

Figure A1.3 demonstrates the overall, EU-wide consequences for installed capacity of using EXT and AVG lifetimes for the units in the bottom-up assessment. In all cases, lowering the lifetime of the plants reduced the installed capacities for the illustrative sectoral profiles, as would be expected, as a result of higher rates of decommissioning. The amount of decommissioning by 2014–2015 is unrealistic when using the lower, average-age variant.

Table A1.1 Extended (EXT) and historic average (AVG) lifetime variants (years)

Type	EXT profile	AVG profile
Solid fuels	50	40
Liquid fuels	50	40
Gas	45	35
Nuclear power	60	50

Figure A1.3 Total installed capacity in the EU-28 (GWe)



	2014 EXT	2014 AVG	2020 EXT	2020 AVG	2030 EXT	2030 AVG
Uranium	129	129	136	136	159	136
Solid	147	147	142	96	104	65
Oil	26	26	22	5	5	1
Gas	137	137	171	165	194	190

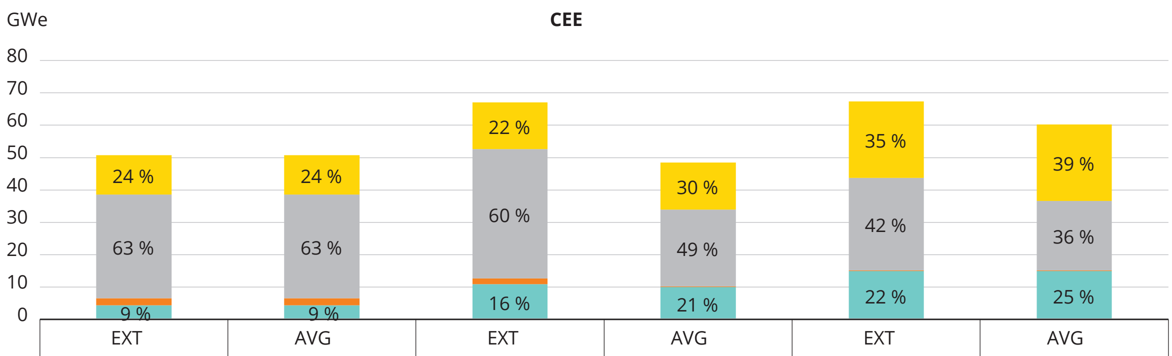
Source: EEA (based on Platts, 2014; and own calculations).

Overall reductions in installed capacity by fuel type reflect the age distribution of these plants, and therefore it is important to look at relative shares by fuel type. For 2014, the relative shares of solid fuel and oil-fired capacity increased, and uranium and gas-fired capacity decreased from the extended lifetime to the average lifetime. This indicates that solid and liquid fuel plants are generally older than uranium and gas plants. These trends are carried across all three years. Choosing average lifetimes over extended lifetimes would therefore yield a lower proportion of capacity for those fuel types with higher ages, as well as less absolute capacity for all fuel types.

Lifetime sensitivity in central-eastern Europe

In CEE, the capacity dropped when lifetimes were lowered to the average age variant (Figure A1.4). Relatively speaking, the share of coal-fired capacity decreased both for 2020 and 2030 when using the average age variant, because the installed gas-fired capacity did not change as much. This indicates a prevalence of 'newer' gas-fired facilities, and a large stock of older coal-fired capacity. There are also many older oil-fired plants in CEE, leading to lower proportions of oil-fired capacity in both relative and absolute terms when using the average lifetimes.

Figure A1.4 Installed capacity in central-eastern Europe (GWe)



	2014 EXT	2014 AVG	2020 EXT	2020 AVG	2030 EXT	2030 AVG
Uranium	12	12	15	15	24	24
Solid	32	32	40	24	29	21
Oil	2	2	2	0	0	0
Gas	4	4	11	10	15	15

Source: EEA (based on Platts, 2014; and own calculations).

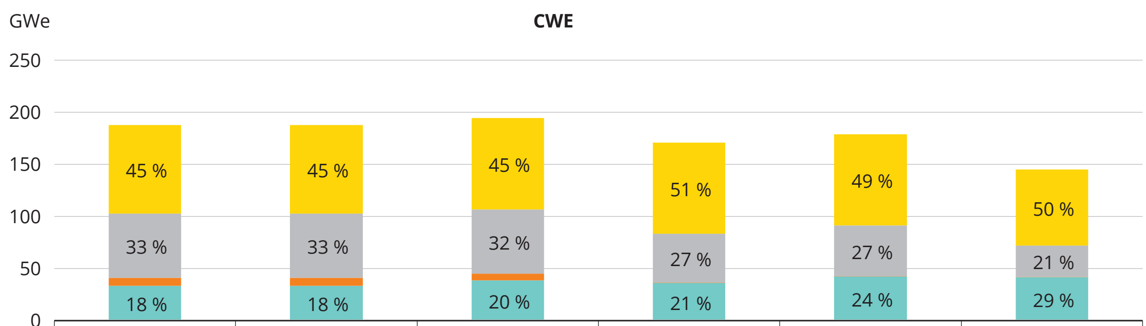
Lifetime sensitivity in central-western Europe

In CWE, the proportions of oil and solid fuel-fired capacity decreased and gas and uranium capacity increased between the extended and the average lifetimes (Figure A1.5). This indicates that the average lifetime variant decreases the proportions of older power plants (solid fuel and oil) and increases the proportion of relatively newer plants (gas and uranium).

Lifetime sensitivity for northern Europe and the Baltics

In NEB, the proportions of uranium and gas-based capacity grew, and the proportion of oil- and solid fuel-fired capacity decreased (Figure A1.6). This is due to, comparatively speaking, a prevalence of 'newer' uranium and gas capacities and less 'older' coal- and oil-fired units.

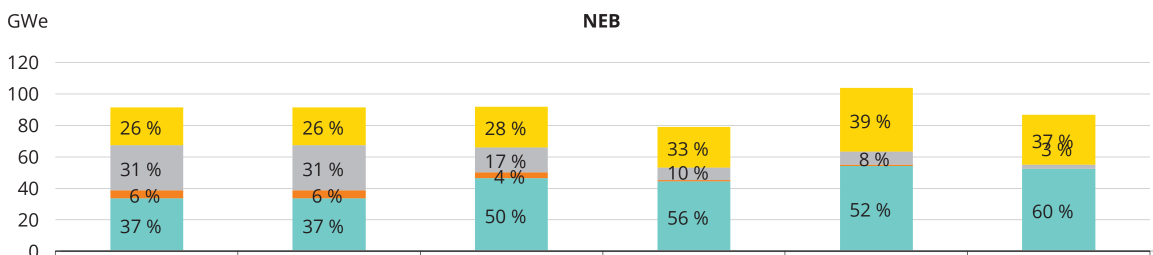
Figure A1.5 Installed capacity in central-western Europe (GWe)



	EXT	AVG	EXT	AVG	EXT	AVG
	2014		2020		2030	
Uranium	85	85	88	88	88	73
Solid	62	62	62	47	49	30
Oil	8	8	7	0	0	0
Gas	33	33	39	36	42	42

Source: EEA (based on Platts, 2014; and own calculations).

Figure A1.6 Installed capacity in northern Europe and the Baltics (GWe)



	EXT	AVG	EXT	AVG	EXT	AVG
	2014		2020		2030	
Uranium	24	24	26	26	40	32
Solid	29	29	16	8	8	3
Oil	5	5	4	1	1	0
Gas	34	34	46	45	54	52

Source: EEA (based on Platts, 2014; and own calculations).

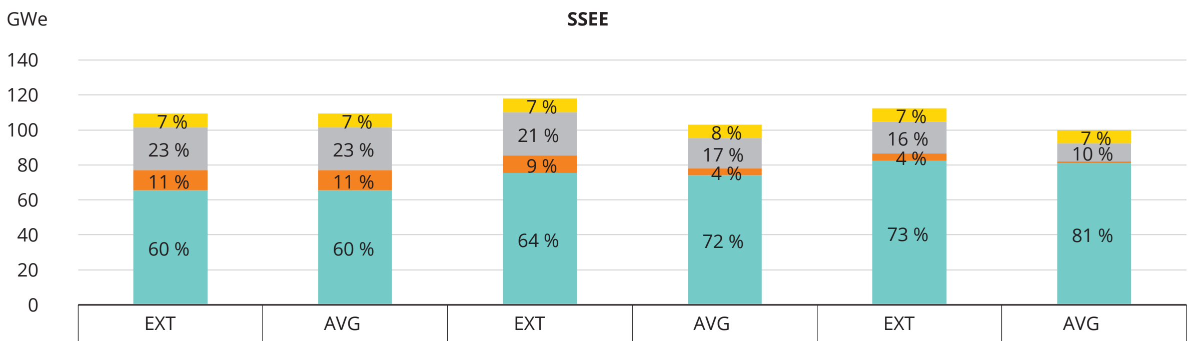
Lifetime sensitivity for south and south-eastern Europe

The relatively low age of plants in SSEE means that the change in lifetime from the extended to the lower (average), variant did not have as significant an impact on installed capacity as in the other regions (Figure A1.7). Owing to the relative ages of plants by fuel type, the proportions of oil and solid capacity decreased, which was compensated for by an increase in uranium and gas facilities.

Lifetime sensitivity in capacity decreases

It is important to consider the relative decreases in each region's installed capacity from the extended to the lower lifetime variants (Figure A1.8). As was shown in the regional analysis, SSEE tended to experience the lowest relative decrease in capacity between the two lifetime methodologies, indicating a prevalence of newly installed capacity. CWE followed this trend too, albeit experiencing a greater decrease in capacity in 2030, largely due to the aforementioned prevalence

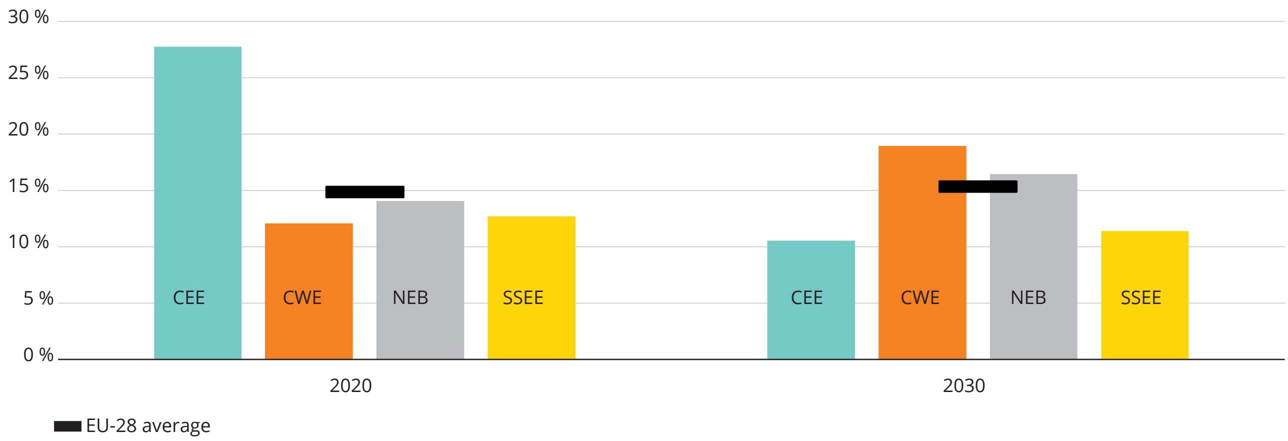
Figure A1.7 Installed capacity in south and south-eastern Europe



	2014 EXT	2014 AVG	2020 EXT	2020 AVG	2030 EXT	2030 AVG
Uranium	8	8	8	8	8	7
Solid	25	25	25	17	18	10
Oil	12	12	10	4	4	1
Gas	65	65	75	74	82	81

Source: EEA (based on Platts, 2014; and own calculations).

Figure A1.8 Decrease in regional capacity (%) from EXT to AVG lifetime variant



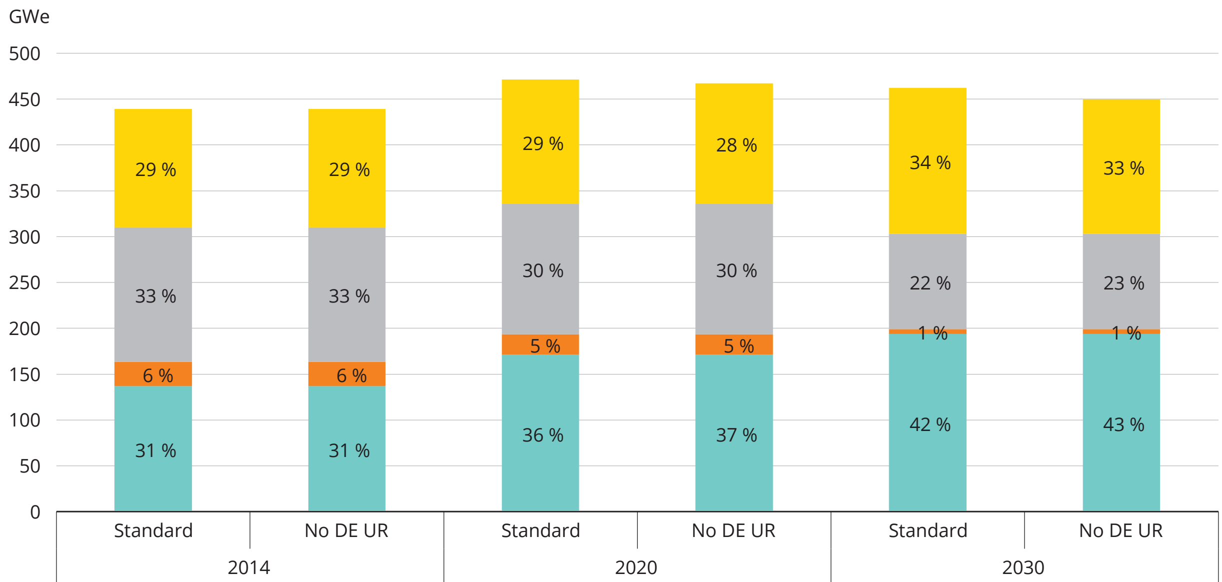
Source: EEA (based on Platts, 2014; and own calculations).

of solid fuel-based capacity built in the 1980s. CEE experienced high rates of decommissioning using the average lifetimes variant for 2014 and 2020, with a marked decrease in 2030, due to the large proportion of capacity that was built before 1980 already having been decommissioned, combined with a spike in construction post 2015 that was yet to be decommissioned. NEB experienced a considerable decrease in capacity in 2014 when the plants installed during the construction spike in 1960–1980 were decommissioned early. The lower rates of decrease in capacity in 2020 and 2030 are testament to the prevalence of newer plants constructed from 2000 onwards (about 50 % of the database capacity in the region).

The consequences of early decommissioning of nuclear power plants in Germany

Accelerating the decommissioning of German nuclear power plants to '2011 shutdown and closure plans' ([42]) has a slight impact on the overall energy profile. In Figure A1.9, the extended lifetimes variant in combination with these new nuclear lifetimes for Germany ('No DE UR') were compared with the extended lifetimes variant. As such, there was no difference in the liquid, gas and solid fuel capacities and only a slight decrease in the uranium capacity. The year 2014 used real statistics and hence did not require accelerated decommissioning data. By 2020, with over half of the nuclear capacity shut down, the total share of nuclear power in the EU profile dropped from 29 % to 28 %, which was compensated for by proportionate increases in the other fuels. The decommissioning of the remaining plants between 2020 and 2022 saw another percentage decrease in the share of nuclear power in the EU in 2030, dropping from 34 % to 33 %. As can be ascertained from Figure A1.9, the consequences of accelerating the decommissioning of nuclear power plants in Germany are visible but not of extreme significance.

Figure A1.9 Comparison of extended (EXT) lifetimes variant with an extended (EXT) lifetimes variant and accelerated German nuclear decommissioning lifetimes



	2014 Standard	2014 No DE UR	2020 Standard	2020 No DE UR	2030 Standard	2030 No DE UR
Uranium	129	129	136	131	159	147
Solid	147	147	142	142	104	104
Liquid	26	26	22	22	5	5
Gas	137	137	171	171	194	194

Source: EEA (based on Platts, 2014; and own calculations).

([42]) As presented by the World Nuclear Association: http://www.world-nuclear.org/info/Country-Profiles/Countries-G-N/Germany.

Carbon dioxide emissions sensitivity

Carbon capture and storage

To find a potential explanation for the higher carbon dioxide emissions resulting from the bottom-up assessment compared with the Roadmap scenarios, the impact of the CCS developments that are included in the PRIMES scenarios but not in the bottom-up database was considered. By adding projected CCS levels from the Energy Roadmap 2050 scenarios for 2020 and 2030, the final carbon dioxide emissions, including captured carbon, increased slightly ([43]). This increase was insignificant, however, when compared with the total difference in carbon dioxide emissions between the bottom-up calculations and the Roadmap scenarios.

Table A1.2 Carbon capture and storage capacity (EU-27)

Year	CCS-equipped capacity (GWe) in net generation capacity (EU-27, Roadmap scenarios, unadjusted)		
	DST	EE	RES
2020	3	3	3
2025	3	3	3
2030	3	3	3
2035	32	17	6
2040	95	59	22
2045	160	111	42
2050	193	149	53

Notes: DST, diversified supply technologies; EE, high energy efficiency technologies; RES, high contribution from renewable energy sources.

Source: EEA (based on EC, 2011c).

Fuel switching

In the explanation of the assumptions made in the Energy Roadmap 2050 scenario it is indicated that, in addition to CCS, fuel switching will have a large impact on reducing carbon intensity over the projected years. To test the impact of fuel switching between the bottom-up calculations of the illustrative profiles and the top-down Roadmap scenarios, the previously mentioned fuel-specific carbon intensities from the REV profile were applied to the (adjusted) energy production in the Roadmap scenarios. The results, presented below in Figure A1.10, demonstrate that the share of fuels in the illustrative bottom-up profiles generates proportionally similar carbon dioxide emissions as the Energy Roadmap scenarios, using selected fuel-specific carbon intensities. Carbon dioxide emissions are calculated by multiplying the energy generation values by a fuel-specific carbon intensity from the database underpinning this assessment. This suggests that, had the fuel-specific carbon intensities been similar, the carbon dioxide emissions would have been proportional to the energy production. This in turn indicates that fuel switching did not have a large impact on the differences in carbon dioxide emissions, but rather that the fuel-specific carbon intensities had a large impact (for, if they had been the same, the results would have been much more consistent). The possible use of lower fuel-specific carbon intensities in the Roadmap scenarios may be inferred from the statement that 'technologies are assumed to develop over time and to follow learning curves' ([44]), although this is potentially negated by the already known discrepancy for the year 2014–2015.

Table A1.3 Carbon capture and storage (EU-27) ([a])

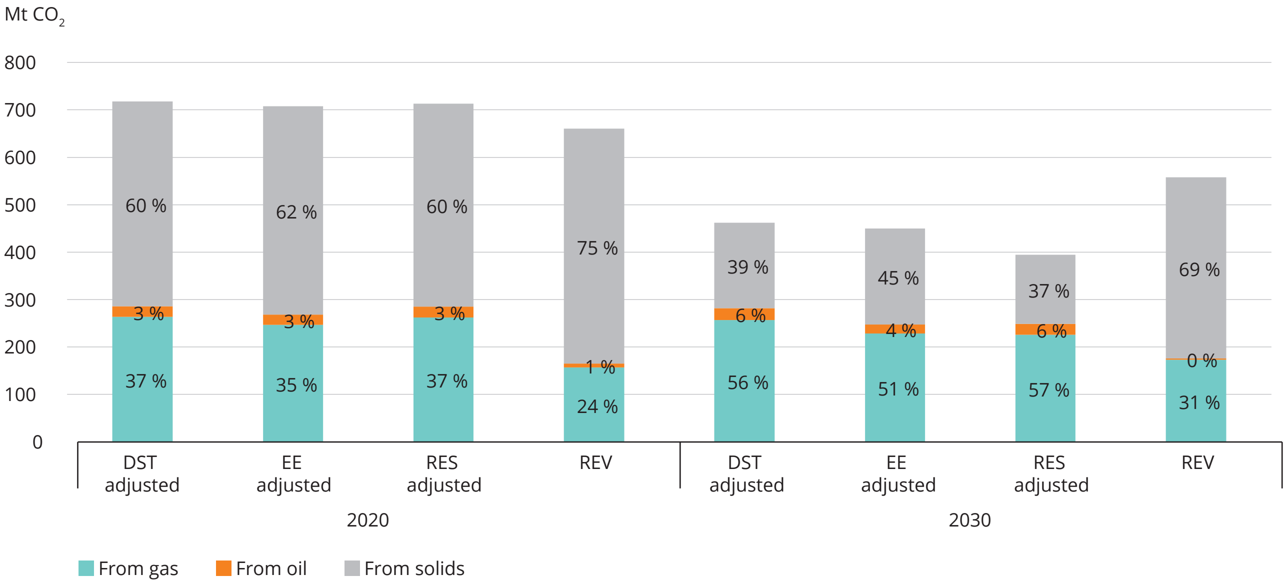
Scenario	2020			2030		
	Emitted kt CO_2	Captured kt CO_2	Total kt CO_2	Emitted kt CO_2	Captured kt CO_2	Total kt CO_2
Diversified supply (DST adjusted)	606 744	10 135	616 879	369 383	12 042	381 425
High-RES (RES adjusted)	603 641	9 574	613 215	322 737	8 562	331 299
High energy efficiency technologies (EE adjusted)	604 322	7 731	612 053	370 542	9 158	379 700
Bottom-up (REV profile)		0	660 242		0	558 030
Bottom-up (EXT profile)		0	660 983		0	532 774
Bottom-up (AVG profile)		0	473 080		0	393 544

Note: ([a]) Assuming that CCS is implemented only in plants ≥ 200 MWe.

Source: EEA (based on EC, 2011c).

([43]) The average efficiency used for carbon dioxide capture is 85 %, as presented in IEA, 2013.
([44]) Energy Roadmap 2050; https://ec.europa.eu/energy/sites/ener/files/documents/sec_2011_1565_part1.pdf.

Figure A1.10 Carbon dioxide emissions adjusted for constant carbon intensity



Notes: DST, diversified supply technologies; EE, high energy efficiency technologies; RES, high contribution from renewable energy sources.

Source: EEA (based on EC, 2011c; Platts, 2014; the LCP-EPRTR and ETS databases and own calculations).

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