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Scenario analysis of accelerated coal phase-out by 2030

A study on the European power system based on the EUCO27 scenario using the METIS model

Kanellopoulos K.

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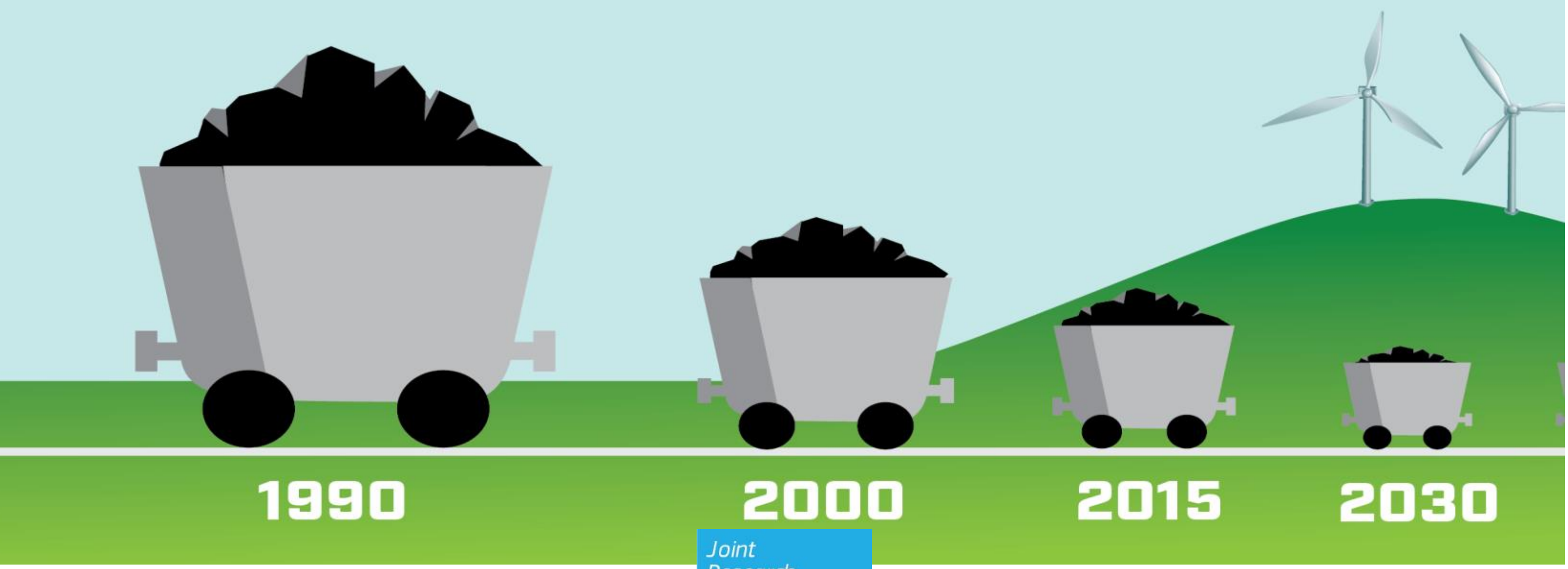

Joint Research Centre

EUR 29203 EN

Contact information
Name: Kostas Kanellopoulos
Address: European Commission, Joint Research Centre, P.O. Box 2, 1755LE Petten, the Netherlands
Email: konstantinos.kanellopoulos@ec.europa.eu

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Contents

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Authors

Kostas Kanellopoulos

Abstract

The present report is a hands-on exercise by the European Commission's Joint Research Centre (JRC) using the METIS model (Artelys, 2017). The area covered by the analysis extends to the 28 EU member states plus Norway, Switzerland and the Western Balkans. The model is used on two variations of the European Commission EUCO27 scenario built to simulate the impacts of an accelerated coal phase-out policy unfolding during the next decade. One of the first results is that the simulated coal-fired capacity retirement will lead to conditions of insufficient power adequacy in certain areas. The two new scenarios restore adequacy by expanding the European power system in two opposing directions. The first is an expansion-as-usual scenario, based on new thermal peaking capacity. The second represents a scenario, where additional optimally placed renewable capacity, coupled with interconnection upgrades and limited storage, appear equally effective in restoring adequacy to the affected regions.

1 Introduction

Coal power generation is at a crossroad. For over half a century it has been the backbone of most European power systems, contributing to energy affordability and security of supply. However, in a context of accumulating scientific evidence on the role of anthropogenic CO_2 emissions in climate change and the impact of coal use on air pollution, the public's awareness regarding the associated external costs of coal has been constantly rising, with various segments of European society supporting measures to accelerate coal phase-out.

European countries, including Austria, Denmark, France, Germany, Italy, the Netherlands, Finland, Portugal, Sweden and the UK have all recently announced the phase-out of all coal-fired capacity within the next decade while in Belgium the last coal-fired power plant was retired in 2016[1]. In particular the UK government intends to proceed with actions to regulate the closure of unabated coal power generation units in Great Britain by 2025 (UK government, 2017)[2]. The Italian government intends to cease the use of coal by accelerating in 2025 an infrastructure investment programme which will enable coal phase-out (Ministero dello sviluppo economico, 2017)[3]. The French government announced in November 2017 the intention to phase-out coal by 2023. Germany's Climate Action Plan provided for the establishment of a commission, tasked with developing a coal phase-out plan by mid-2017.

On the European Policy front, the European Commission included a 550g/kWh emissions threshold for power plants eligible to participate in capacity remuneration mechanisms in its proposed regulation establishing the framework for an internal electricity market across the EU, sparking reactions [4,5] by stakeholders and the scientific community.

It becomes therefore very relevant to analyse what the European power system would look like in 2030 should coal phase-out policies be more widely implemented during the next decade, to assess the environmental benefits and estimate the potential costs. METIS, a mathematical model which offers the capability to analyse the European power system on an hourly basis over a year, while also factoring weather induced uncertainties on demand and generation, is used in this analysis.

In Section 2 we briefly present the evolution of coal-fired installed capacity assumed in our coal phase-out scenarios.

In Section 3 we describe how two new scenarios (or contexts in the METIS terminology) were created based on the EUCO27 after adjusting the hard coal and lignite fleets, and installing new capacity to restore adequacy indicators to their former levels.

In Sections 4 and 5 we present the results of the two new scenarios and compare them with the EUCO27.

A summary of the conclusions of the present analysis is provided in the closing Section 6.

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[1] https://beyond-coal.eu/wp-content/uploads/2017/12/National-phase-out-overview-171219.pdf

[2] https://www.gov.uk/government/publications/clean-growth-strategy

[3] http://www.sviluppoeconomico.gov.it/index.php/it/194-comunicati-stampa/2037349-ecco-la-strategia-energetica-nazionale-2017

[4] https://www.eurelectric.org/news/study-commissions-550-eps-rule-will-add-costs-to-the-energy-transition/

[5] https://ec.europa.eu/energy/sites/ener/files/documents/ntua_publication_mdi.pdf

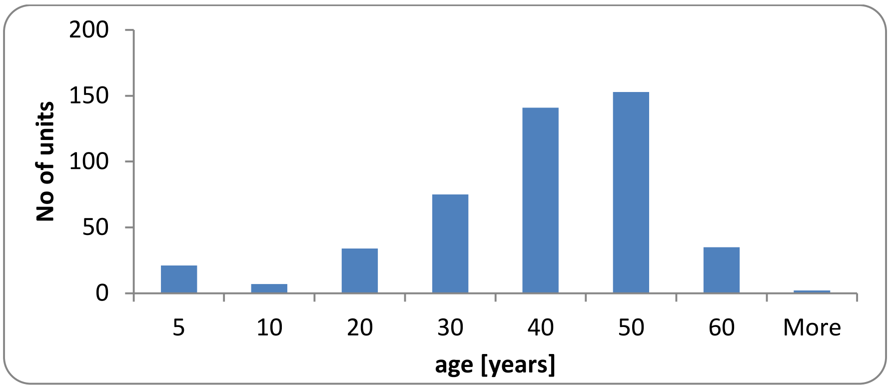
2 Study objectives

The objective of this report is a hands-on exercise by JRC on METIS. This exercise uses the European Commission EUCO27[6] scenario (E3MLab & IIASA, 2016) , and henceforth called EUCO27, as the basis to which assumptions are applied, regarding installed capacity of coal fired power plants after the implementation of accelerated coal phase-out policies by 2030. The area covered by the analysis extends to the 28 EU member states plus Norway, Switzerland and four countries in the Western Balkans (Bosnia and Herzegovina, Montenegro, Serbia and the former Yugoslav Republic of Macedonia).

2.1 A snapshot of European coal power plants

In the next decade pressure on the competitiveness of coal is expected to rise, while the European coal fleet will be ageing. The graph in Figure 1 shows the age distribution of the European coal power plant fleet. The average age of a coal power plant in the EU is 35 years, while the vast majority of coal-fired plants in Europe were commissioned more than 30 years ago.

Figure 1 Age distribution of the European coal power plant fleet[7].



Coal-fired power plants are typically designed for a service life of more than 25 years without significant upgrades. While the service life can be significantly extended beyond that timeframe by replacing or upgrading components, the increasingly important share of renewables, the anticipated restrictions on coal eligibility to participate in future capacity remuneration mechanisms, the post 2020 emission requirements of the Industrial Emissions Directive (2010/75/EU), as well as uncertainty over prevailing CO_2 prices after 2020 are a few of the factors that the coal power plant operators would obviously consider before proceeding with any life-extension investment.

2.1.1 New entries

It looks unlikely that the European coal fleet will be replaced by new, higher efficiency power plants on the same fuel. New coal fired capacity, either under construction, or expected to come online until 2025, at country level, is provided in Table 1. It consists of a handful of projects, in Poland and three plants in Germany, Greece and Croatia.

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[6] One of the two core policy scenarios prepared for the European Commission in the context of the 2016 Impact Assessment work.

[7] The JRC-PPDB is a comprehensive database of power plants in Europe that contains a plethora of information, such as location, capacity, fuel, age, technology type, cooling type, estimated efficiencies and other operational parameters. The database, developed by JRC, draws information from open and confidential sources such as ENTSO-E, Platts and E-PRTR.

Table 1. Coal power plant capacity under construction or expected to come online before 2025

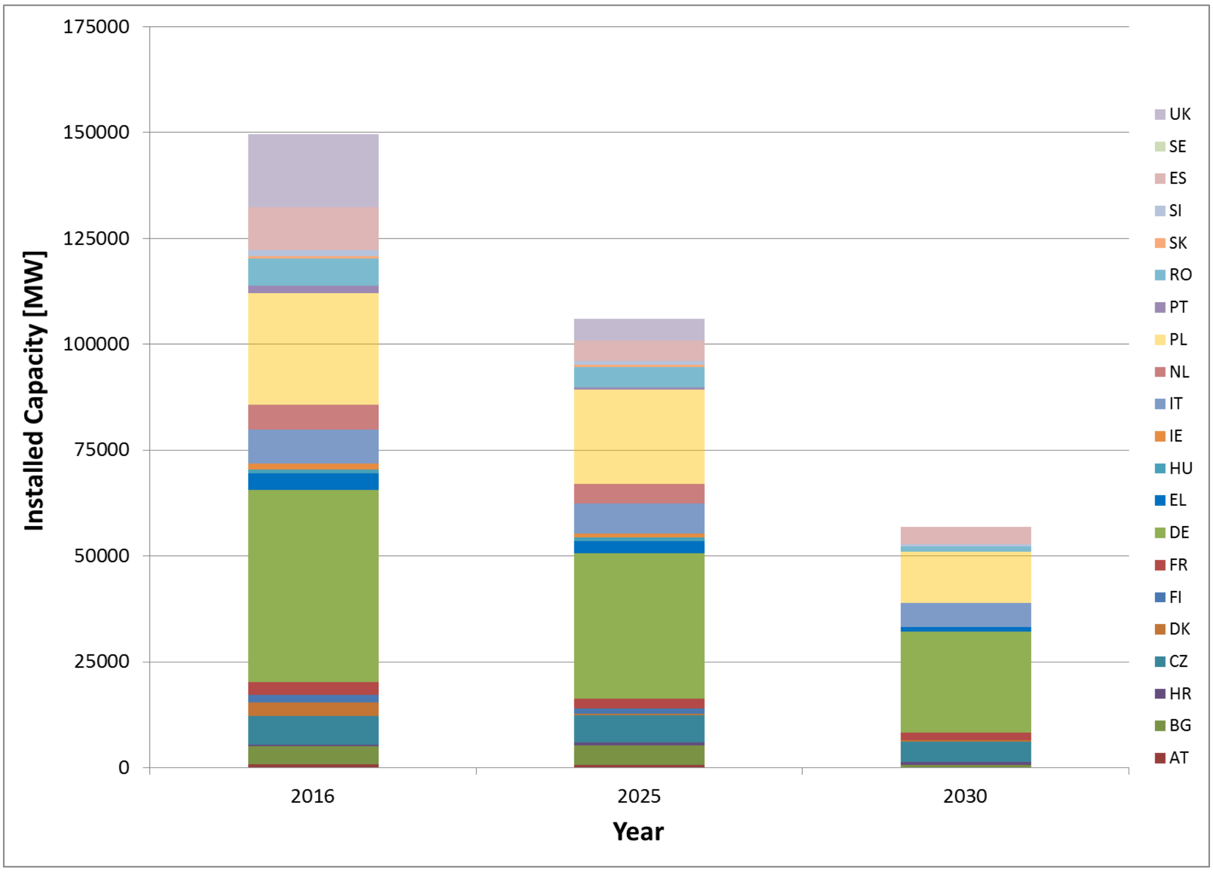
Country	Capacity [MW]
Poland	4 465
Germany	1 100
Greece	660
Croatia	500

The recent decision by DG Competition to approve a market-wide capacity remuneration mechanism in Poland[8] enables the Polish authorities to guarantee the operation of these plants until 2030, but based on current knowledge it's hard to foresee very positive prospects for coal much beyond that timeframe.

2.1.2 The coal fleet in 2030

Figure 2 below is sourced from JRC internal work conducted during 2017 and presents a possible evolution in time of coal-fired installed capacity, based on ENTSO-E's TYNDP - Vision 4 (ENTSOE, 2016)[9] slightly adjusted, to bring it in line with the national coal phase-out strategies mentioned in the introduction.

Figure 2 Installed hard coal and lignite-fired capacity in 2025 and 2030 (ENTSO-E)



Should this scenario materialise, only one third of the current installed hard coal and lignite capacity in the EU will still be in operation by 2030. In absolute numbers total

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[8] http://europa.eu/rapid/press-release_IP-18-682_en.htm

[9] Ten Year Network Development Plan 2016 (http://tyndp.entsoe.eu/)

installed capacity could drop from 150 GW in 2016 to about 105 GW in 2025 and around 55 GW in 2030. Table 6 in Annex 1 provides the assumed hard coal and lignite fleet installed capacity per member state in 2030.

Based on this vision regarding a possible evolution of coal fired capacities in Europe two new contexts, expressing two opposing philosophies, were created in METIS. The implementing steps are described in the following chapter.

3 Creation of the new contexts

The new METIS contexts (the technical term used by the METIS developers to describe the set of techno-economic input required to set up a simulation scenario) were created, in order to assess the implications of coal phase-out. The starting point for either is the existing EUCO27 scenario for 2030. Since the alternating use of the terms scenario and context may create some confusion, the table below lists the association between the general *scenario* term and the native METIS *context* term[10].

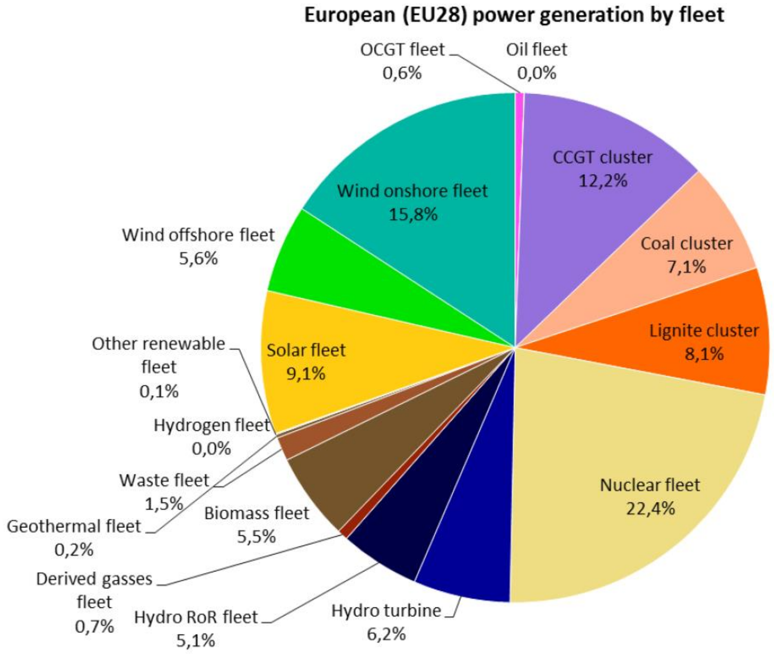
Table 2. Scenarios names and associated METIS context

Scenario	METIS Context	Description of changes
EUCO27	EUCO27_2030	-
ACD	EUCO27_ACD0	EUCO27 after adjusting solid fired capacity
ACD_base	EUCO27_ACD	ACD after adding thermal peaking units
ACD_res	ACD_res	ACD after installing onshore wind and interconnections

Throughout the rest of the report we will be using the term context mostly when discussing input and the term scenario mostly when referring to the actual case studies and the results.

3.1 Overview of the EUCO27_2030 context in METIS

A detailed description of the EUCO27_2030 context and how it was generated based on EUCO27 data is provided in (Artelys, 2016)[11]. The chart below provides the shares of generation by fleet type in the EU28.



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[10] A context is the dataset structure used by METIS. It contains all the input data, as well as the results, belonging to each scenario analysed in METIS.

[11] https://ec.europa.eu/energy/sites/ener/files/documents/metis_technical_note_t1_-_integration_of_primes_scenarios_into_metis.pdf

The price for CO2 emissions in the EUCO27_2030 is 38.5 €/tCO2. We assume this value to be fixed at this value in the two new derivative scenarios.

3.2 Climatic year assumptions

The EUCO27_2030 context in METIS allows the assessment of weather effects on load and renewable generation by including the relevant climatic data from different years. The analysis presented in the following paragraphs is based on climatic data that describe an average year (2001).

3.3 Adjusting the installed capacity

Hard coal and lignite capacities were reduced for each country to the corresponding values presented in section 2.1.2 and Annex 1, while keeping all other parameters unchanged with regard to the EUCO27_2030. It was assumed that 7 GW of hard coal and lignite capacity is converted to biomass. Overall the capacity changes applied to the solid fired capacity are provided below:

- Withdrawals : hard coal and lignite 53 GW
- Additions : biomass 7 GW

3.3.1 Hard coal and lignite retirement

Under the ACD scenario we assume that by 2030 the coal fleet in Europe will consist of 36 GW (or 55%) less installed capacity while the lignite fleet will consist of 17 GW (or 37%) less installed capacity compared to the EUCO27 scenario.

3.3.2 Biomass

Biomass plays a significant role in the energy planning of several member states (Denmark, Netherlands and the UK). The ACD scenario assumes that 7 GW of the decommissioned hard coal and lignite plants will be converted to run on biomass. This capacity is located in the Netherlands (2.8GW), Poland (3.5 GW) and Greece (1 GW). The numbers for the first two countries are direct input from ENTSO-E's TYNDP (ENTSOE, 2016) vision 4 scenario. The number for Greece makes use of the maximum biomass potential (Ruiz, Sgobbi, Nijs, & Thiel, 2015) that could be used for "greening" the lignite plants serving district heating networks.

3.3.3 Adequacy implications

The full year optimal dispatch simulation of the new context with the adjusted capacities (EUCO27_ACD0) identified an adequacy issue. After the retirement of the coal capacity the power systems in several countries in central Europe, the UK and Ireland are not able to satisfy demand at all times. The time series of the load curtailment (around 40-300 hours) identify a shortage of peaking capacity primarily caused by recurring events of low renewable generation during peak hours. This means that the accelerated coal phase-out presented previously will create the need for additional peaking capacity. Possible remedies to the observed lack of adequacy were explored in two different scenarios.

The first scenario represents the business-as-usual solution, which requires less planning, can be implemented very quickly, in response to a possible critical situation of long term absence of adequate market signals for building new capacity. This scenario builds upon thermal peaking capacity to ensure short term adequacy. The METIS implementation of this scenario assumes that open cycle gas turbines (OCGTs) will be installed as peaking capacity in countries exposed to lack of adequacy. This is called the "ACD_base" scenario.

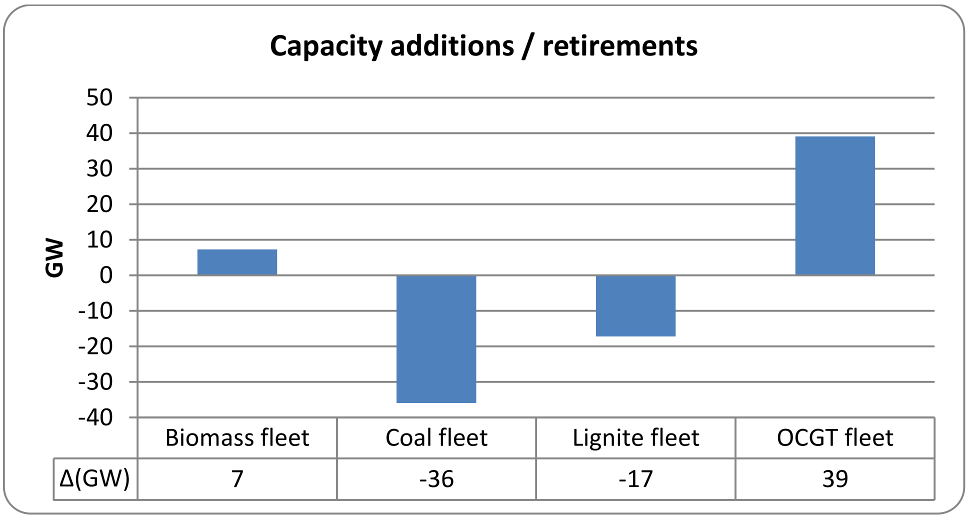
The second scenario explores the opportunities presented to the power systems in Europe at the present crossroad. This scenario builds upon the non-fossil fuel technologies, requires significant planning and cross border cooperation and therefore can be unfolded in significantly longer time spans. The METIS implementation of this scenario is based on the addition of wind power coupled with storage, interconnection reinforcement and, if needed, thermal peaking backup. This is called the "ACD_res" scenario.

The two scenarios correspond to opposing philosophies with different requirements on anticipatory planning and cross border cooperation. It is likely that, in reality, if accelerated coal phase-out takes place towards the end of the next decade, the actual evolution of the power system could lie in-between these two scenarios.

3.4 The ACD_base scenario

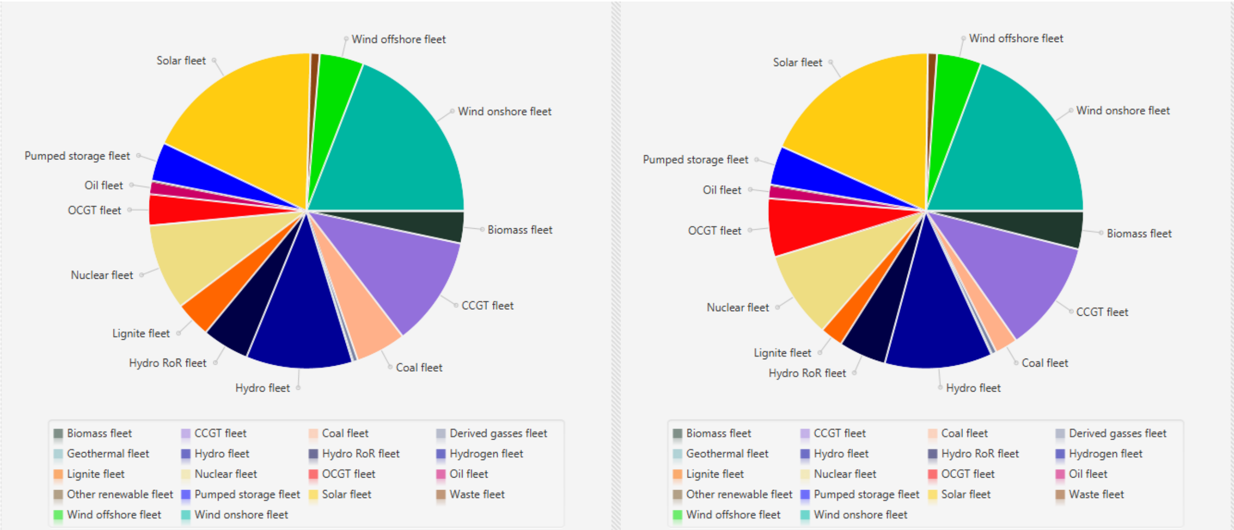
As mentioned above, the accelerated coal phase-out will require the addition of new capacity to restore system adequacy. In this scenario thermal peaking units (gas turbines) are added to the power system until the adequacy indicators are very close or identical to those in the EUCO27 scenario. The figure below provides an overview of the capacity additions and retirements of the various technologies in the ACD_base scenario with respect to the EUCO27.

Figure 3 Installed capacity changes between the EUCO27 and the ACD_base scenario



The total new thermal peaking capacity required is 39 GW. A side by side overview of the total installed capacity by technology for the two contexts is provided in the figure below.

Figure 4 Fleet installed capacity shares in EUCO27 (left) and the ACD_base scenario (right)



The ACD_base scenario is not the result of an optimisation process. It represents an expansion –as-usual scenario, in order to understand the implications of a coal phase-out policy. It is also the case against which to benchmark the alternative scenario, called ACD_res, which is based on a mix of peaking, renewable generation and storage technologies and is presented in the paragraphs below.

Although not related in any way, this scenario has conceptual similarities with the "opportunity scenario" developed in a study by the Energy Union Choices consortium (Energy Union Choices, 2017), which identifies a least cost path to replace coal with renewables and flexibility.

3.5 The ACD_res scenario

The ACD_res scenario presents a possible answer to the challenges lying ahead on the path to decarbonisation. The scenario is the result of a stepwise process involving two optimisations of selected key variables.

3.5.1 Creating a zonal scenario

Under the current licensing and hardware restrictions, the capacity expansion module of METIS offers the capability to conduct a capacity expansion of the power system, optimising up to five variables on an hourly simulation for one year. The model was used under these limitations to determine in two steps an optimal mix of carbon free technologies to replace the retired coal capacity. In the first step the generating technologies mix was selected, while in the second step the generating technologies were allocated in two zones.

3.5.1.1 Optimising technologies

The capacity expansion module was used to estimate the mix of wind, solar and storage capacity that could effectively replace the thermal peaking capacity identified in the base scenario. The simulation was conducted considering a single zone for the EU, thereby without considering transmission constraints between nodes-countries. The variables open to optimisation where the following:

- OCGT capacity
- Onshore wind capacity
- Solar capacity
- Lithium ion battery storage

The specific technical and economic characteristics of the technologies used in the optimisation are provided in Annex 2. Cost assumptions from the METIS EUCO27 scenario were used for OCGT, onshore wind and solar, while the cost assumptions regarding li-ion battery systems are based on Schmidt (2017).

The capacity expansion simulations were conducted in a parametric fashion, by sequentially applying constraints to the maximum allowed capacity for each technology. These were applied because onshore wind presents the lowest value of levelised cost of electricity (LCOE) and is thus overall the new technology of choice in the optimisation (See Annex 2). If left unconstrained, the model selects onshore wind until all lost load disappears. Given the lack of transmission constraints in the single zone model the curtailment is insignificant. Therefore wind was constrained in the parametric analysis to identify the most effective capacity mix for replacing thermal peaking capacity. In Annex 3 the values obtained from eight optimisation runs are provided. For the reasons explained above, onshore wind capacity addition in every run is selected by the model up to the maximum allowed value.

The results from run 7 in table 8 (see Annex 3) provide the optimal mix of wind and batteries corresponding to the minimum additional carbon-free capacity needed to fully replace thermal peaking units. This minimum carbon-free capacity totalling 114 GW (96GW wind and 19 GW li-ion capacity) appears capable of most effectively replacing 37.5 GW of additional OCGTs in the task of preserving adequacy in the modelled, single zone, area. The ratio of the additional carbon free capacity equivalent to the thermal peaking units' capacity is approximately 3.04.

3.5.1.2 Optimising location and interconnections

The parametric optimisation in the previous paragraph was performed in a single EU zone, assuming wind and solar capacity is evenly distributed within the area and ignoring transmission constraints. The next step was to conduct a spatial optimisation of the new onshore wind capacity location, aiming to understand which locations offer the most positive contribution to restoring system adequacy. This was implemented by conducting parametric optimisation runs for the European power system split in two zones (north and south). The southern zone includes Bulgaria, Greece, Italy Portugal, Romania and Spain as shown in the figure below.

Figure 5 Map visualising the two-zone model

The capacity expansion simulations were conducted in a parametric fashion, by sequentially changing onshore wind new capacity location (between north and south) and optimising the interconnection capacity between the two zones and li-ion and new OCGT capacities in the northern zone.

Table 3. Parameters in the 2 zone parametric optimisation

Parameter	Type	Value / Range	Zone
Onshore Wind capacity	Upper bound	[0,75] GW	Varying
li-ion storage	Optimised	Unlimited	North
Interconnection	Optimised	Unlimited	South to north
OCGTs	Optimised	Unlimited	North

In Annex 3 the values obtained from 6 optimisation runs are provided. Most useful in understanding the parameter effects are runs 1, 2 and 3, as explained below.

3.5.1.2.1 Optimising interconnections

Run 1 (Table 9 in Annex 3) signals that upgrading the interconnection capacity between the two zones by slightly more than 50% of the EUCO27 capacity (15.9GW) will equally reduce the new thermal peaking requirement in the northern zone.

This result identifies an interconnection bottleneck in the 2030 EU power system with coal phase-out as simulated in the current analysis. This bottleneck is further evidenced in the following section.

3.5.1.2.2 Optimising spatial location of wind

In run 3 all new onshore wind capacity (75 GW) is located in the northern area. In this case the resulting optimal expansion requires an extra 13.6 GW of thermal peaking capacity in the northern area. In run 2 we repeat the exercise by locating 75 GW of new onshore wind capacity in the southern area. This has a much more positive effect as only 0.1 GW of thermal peaking capacity is now required in the northern area. However substantial reinforcement of the interconnection capacity (+36 GW) or more than double the interconnection capacity present in the EUCO27 scenario (15.9 GW) is required to enable the energy surplus in the south to flow to the north. In this case the equivalence ratio of carbon free capacity to thermal peaking units' capacity is approximately 90/41 or 2.2.

This outcome was not very surprising after observing the wind generation time series in the northern and southern regions with respect to the resulting hourly loss of load for the selected climatic year (see para. 3.2). The latter occurs in the northern zone at times when wind and solar production is low. During those times wind production in the southern zone is significantly higher. This result identified by using the capacity expansion module of METIS is further analysed in a separate, external, optimal allocation of wind capacity to the countries as described below.

3.5.2 Creating the detailed scenario

The capacity expansion analysis conducted previously in the zonal representation of the ACD_res scenario indicated that installing a larger fraction of new onshore wind capacity in regions distant to the area where the capacity adequacy concerns are identified (in this case central Europe), is more effective in replacing new thermal peaking capacity. This finding is corroborated through a separate optimisation process, external to METIS, for optimally allocating additional onshore wind capacity at country level.

3.5.2.1 Additional onshore wind capacity

We used the results of the hourly dispatching with METIS of one year in the EUCO27_ACD0 context (the one with coal retirements but no new capacity additions). The resulting loss-of-load time series were then used to optimally allocate an additional 85[12] GW of onshore wind capacity between countries. The optimal allocation is the result of minimising the sum of the maximum and average values of the loss-of-load time series. The outcome of this optimal allocation is illustrated in Figure 6, provided in the following page.

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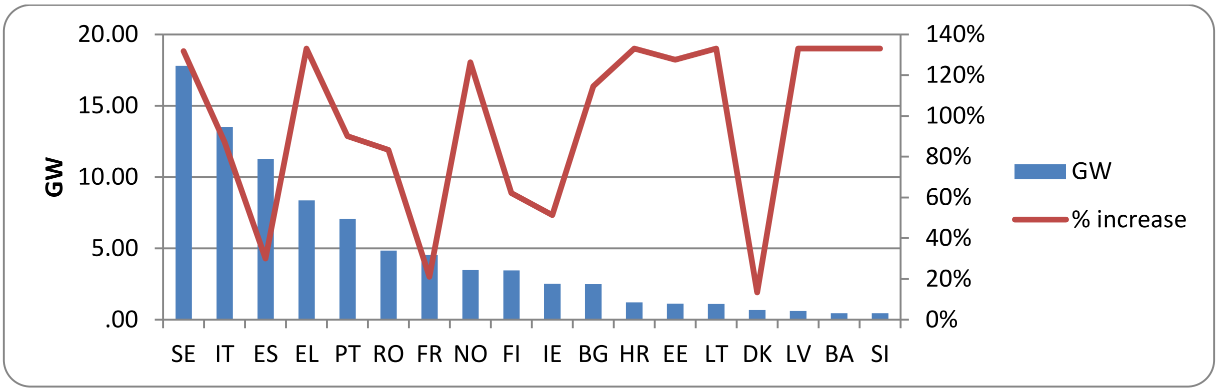
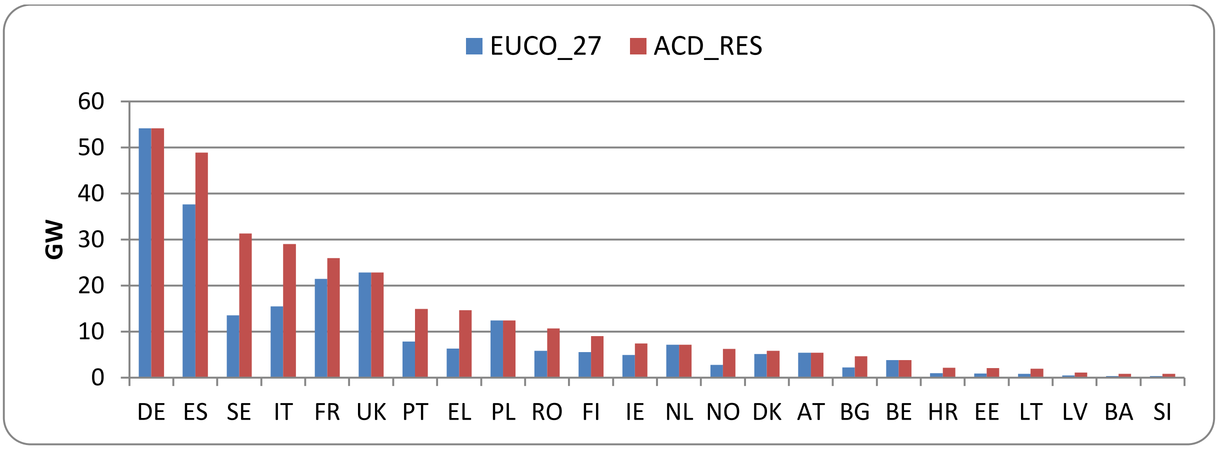
[12] This level of new onshore wind capacity yielded a detailed context with very similar adequacy indicators to the EUCO27

Figure 6 Optimal allocation of the additional 85GW of onshore wind capacity



The value of 133% was used as the maximum allowed increase (over EUCO27 values) in onshore wind capacity in all cases except in the Iberian countries, where network reinforcement constraints, explained in the following section, imposed using much lower limits. The figure below provides the onshore wind capacity increase at country level in the ACD_res scenario with respect to the EUCO27.

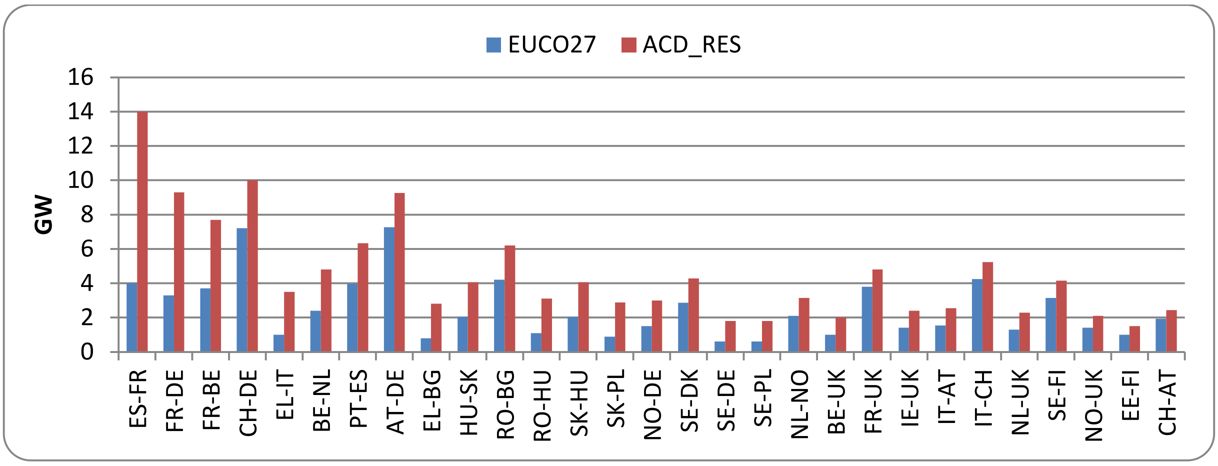
Figure 7 Onshore wind capacity increases at country level



3.5.2.2 Additional interconnection capacity

The capacity expansion runs on two zones presented in paragraph 3.5.1.2.2 indicated that optimally placing new onshore wind capacity in the southern zone would require interconnection reinforcements in excess of 36 GW. The optimal allocation at country level of new onshore wind capacity would require upgrades to effectively enable power to flow from regions with excessive production to regions suffering from insufficient production. The transmission capacity upgrades expressed as NTC values between nodes (countries) are provided Figure 8.

Figure 8 Interconnections in the EUCO27 and ACD_RES scenarios



The NTC values indicated in the graph would relieve the most prominent transmission bottlenecks of the European power system in a way that it would then start resembling the simplified two zone system used in the optimisation analysis described in paragraph 3.5.1.2. It should be noted that since these values are not the result of a global optimisation process but rather the interconnection upgrades needed to relieve congestions and enable wind power transmission, they may exceed the economically justified needs that would be identified through a comprehensive cost benefit analysis.

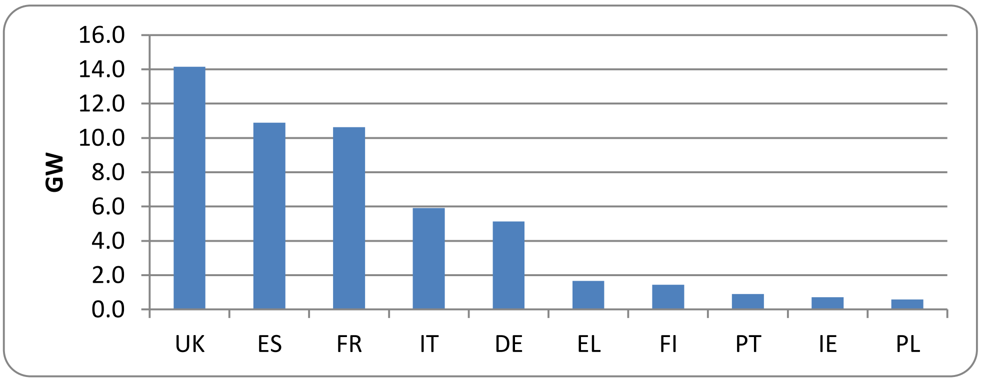
If however the above outcome is viewed alongside the recommendations present in the report of the Commission Expert Group on electricity interconnection targets (Commission Expert Group on electricity interconnection targets, 2017) then the above results become relevant and supportive of that document.

In particular the Expert Group recommends that options of further interconnectors should be urgently investigated in countries where any of the following two indicators are below a threshold of 30%:

a) the ratio of the nominal transmission capacity to the peak load (demand) and
b) the ratio of the nominal transmission capacity to the installed renewable generation capacity (supply).

The following figure provides the interconnection upgrades that would enable the achievement of at least 30% on both indicators in the ACD_res scenario, based on the total NTC and renewable generation capacities (wind and solar) in each country.

Figure 9 Interconnection upgrades required to comply with the recommendations of the Commission Expert Group on electricity interconnection targets

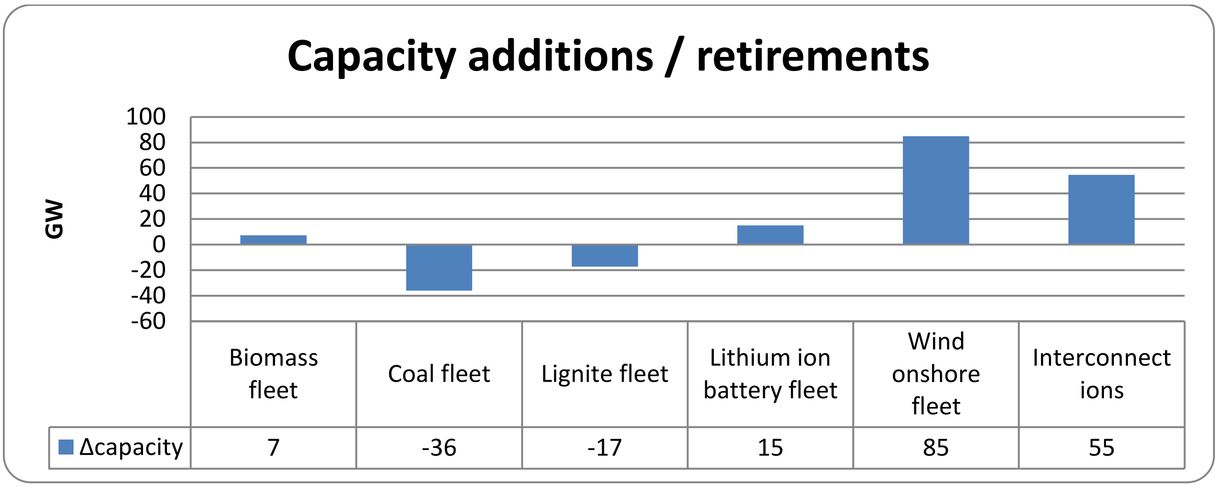


Although not fully aligned for every country, the sums are surprisingly similar. Applying the recommendations would introduce 52 GW of interconnection upgrades.

3.5.3 Capacity additions and retirements in the ACD_res scenario

The individual technology fleet differences between the EUCO27 and the ACD_res scenarios are provided in the figure below.

Figure 10 Installed capacity changes between the EUCO27 and the ACD_RES scenario



3.5.4 Discussion on the capacity differences between the detailed and zonal scenarios

The attentive reader may have noticed apparent differences in the capacity additions between the detailed scenario and the zonal scenario. The table below summarises the most prominent differences, while the ensuing text attempts a brief explanation of the reasons behind them.

Table 4. Zonal scenario vs detailed ACD scenarios fleet capacities (GW)

	Zonal	Detailed (ACD or ACD_RES)
li-ion batteries	15	15
Onshore wind	75 (Upper bound)	85
OCGTs	41	39
Interconnections	36	55

The capacities in the zonal scenarios are the result of a capacity expansion optimisation, aiming to restore adequacy indicators to the acceptable standard with the least cost. The onshore wind capacity in the zonal scenario is limited to 75 GW.

In the detailed scenarios the additional OCGT capacities (39GW) are between the optimal values in the single zone (37.5GW) and the zonal models (41GW). Wind generating capacities are 13% higher compared to the zonal model, to account for the deviation of the detailed scenario from the optimal wind asset location in the zonal scenario. Interconnection capacities are higher in the detailed scenarios, reflecting the interconnection upgrades necessary within the southern or northern zones.

It's apparent from the above that the detailed scenarios are not created as a unique outcome of an optimisation but rather are the result of a stepwise fine tuning process, aligned, to a very large degree, with the zonal capacity expansion optimisation. It is not expected that any further refinement would alter significantly the results of the present analysis.

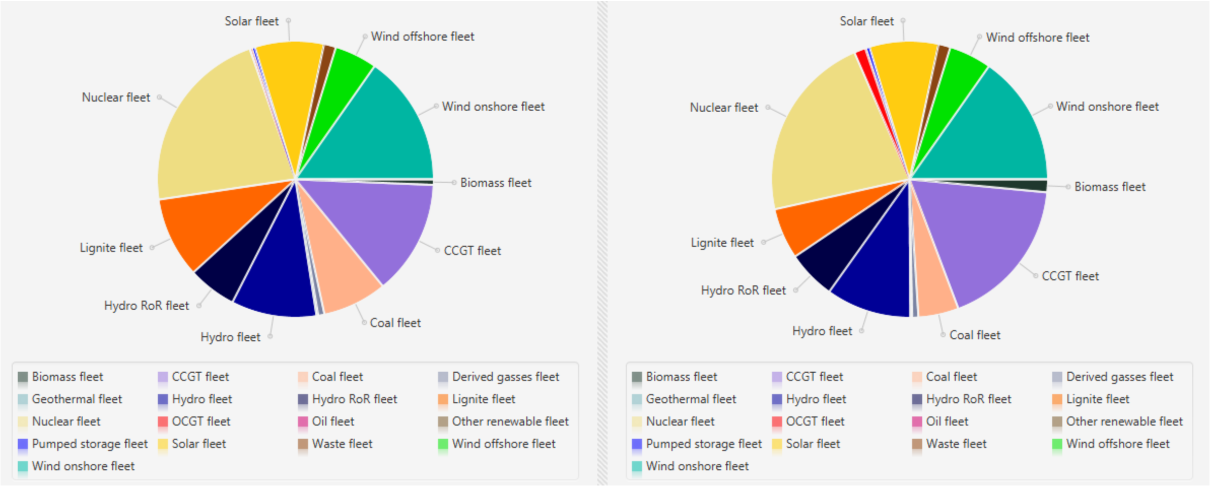
4 ACD_base scenario Results

The assumptions of the ACD_base and ACD_res scenarios and their differences with the EUCO27 scenario were provided in section 3. The present section provides the results produced by METIS, while simulating the power system optimal dispatch for one year in the ACD_base scenario. The results and differences, compared to the EUCO27 scenario, are presented in order to highlight the impact of a coal phase-out.

4.1 Overview of production

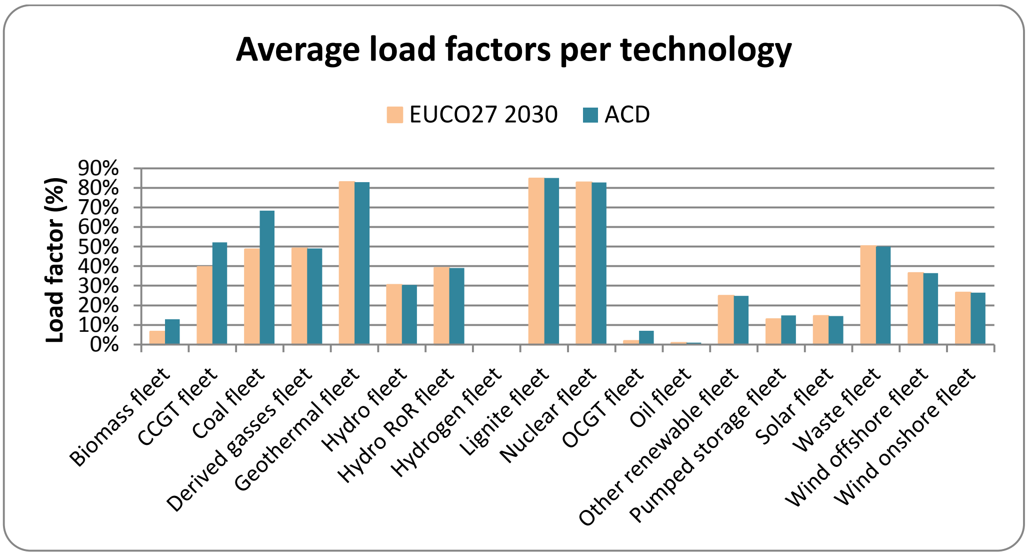
The smaller hard coal and lignite fleet in the ACD0 scenario (coal phase-out as described in section 2.1.2 without newly installed capacities) leads to an energy and capacity deficit. In the ACD_base the energy deficit is filled by CCGT production, while the OCGTs and to a lesser extent, biomass, cover the capacity deficit. The following graph provides a side-by-side comparison of the two contexts, with regard to the share of electricity generated by each technology fleet, across the modelled area.

Figure 11 Generation shares at fleet level in the EUCO27 (left) and the ACD_base (right) scenarios



This is further evidenced by the fleet capacity factors. CCGT operation in the ACD scenario tends to resemble more that of a base load unit (average capacity factor increasing to slightly above 50%).

Figure 12 Fleet load factors in the EUCO27 and the ACD_base scenario



One noteworthy observation is that in the ACD_base scenario virtually all thermal fleets (CCGTs, Biomass and the remaining hard coal capacity) and the pumped storage fleet increase their capacity factors. The increased capacity factors in thermal power plants denote possibly longer operation at higher load, operating at a higher efficiency and emitting less CO_2 per MWh produced. Since this effect is currently not modelled in the examined scenarios, it can be an area of further investigation.

4.2 Costs

The retirement of significant baseload capacity in the ACD_base, compared to the EUCO27 scenario, raises concerns regarding potential increased production costs. Two cost indicators are provided in order quantify the cost impact of the earlier retirement of the European coal fleet. The first indicator is the average marginal cost, while the second is the average production cost.

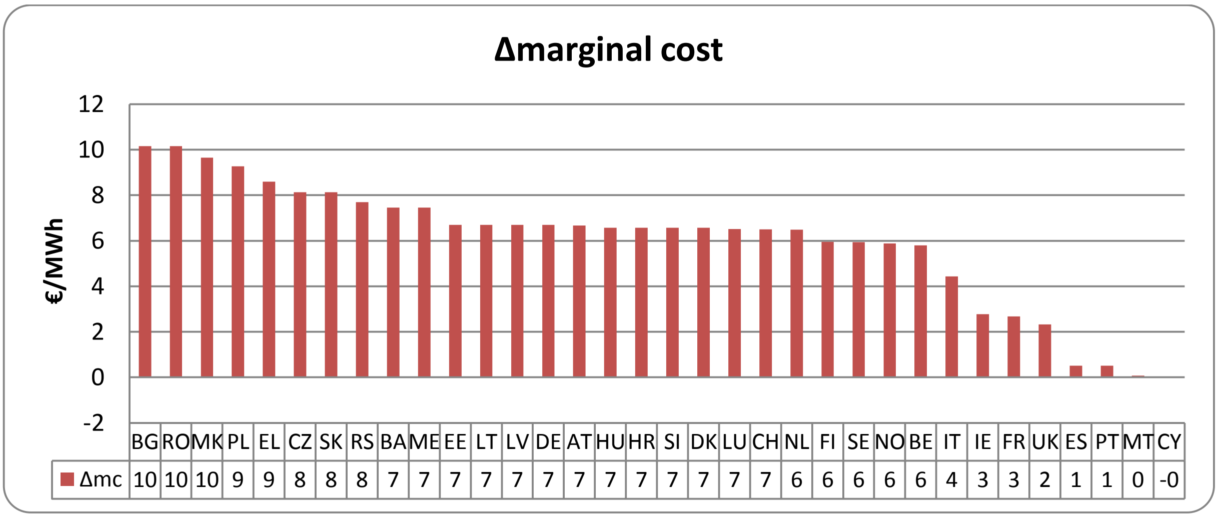
4.2.1 Marginal cost

The average marginal cost, as computed by METIS, is expected to increase for all countries, except Cyprus. Based in the value of the average marginal cost increase, countries may be classified into the following four categories:

1. Countries with negligible or no impact : ES,PT,MT,CY
2. Countries with some impact : (2-3 €/MWh) FR,IE,UK
3. Countries with important impact (6-8 €/MWh) : Scandinavia & central Europe
4. Countries with highest impact (8-10 €/MWh) : BG,RO,MK,PL,EL,SK,CZ

The difference of the average value of the marginal cost computed for each country is provided in the figure below.

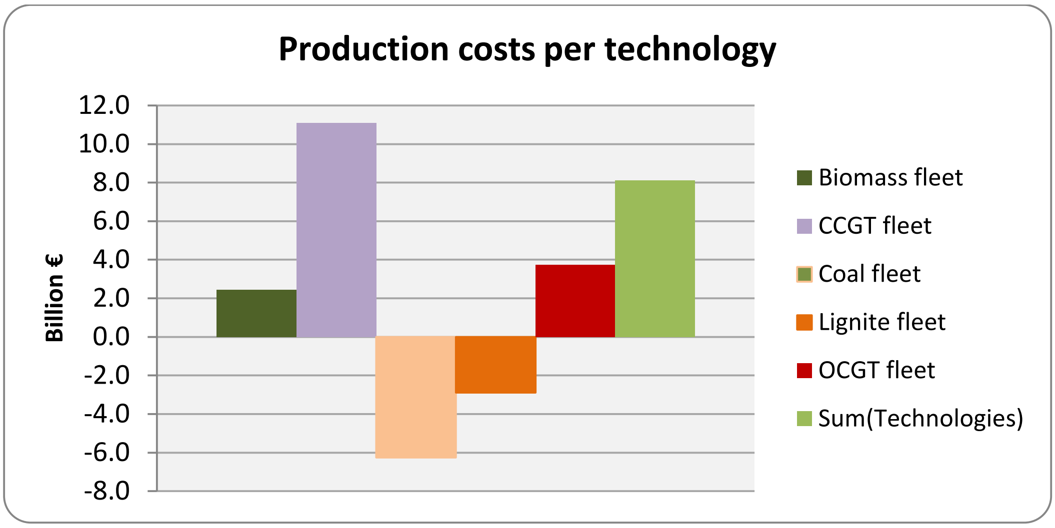
Figure 13 Country average marginal cost increase in the ACD_base vs the EUCO27 scenario



4.2.2 Production cost

The production cost calculated comprises all variable costs plus fixed operating costs, but not the investment costs. The ACD_base scenario is burdened with increased production costs from gas fired and biomass power generation, relative to the production costs of lignite and coal which they substitute. Figure 14 provides the changes in the overall production costs at fleet level. Changes are observed only for the gas fired technologies (CCGTs and OCGTs), biomass, the hard coal and lignite fleets.

Figure 14 Fleet production cost change in the ACD_base vs the EUCO27 scenario

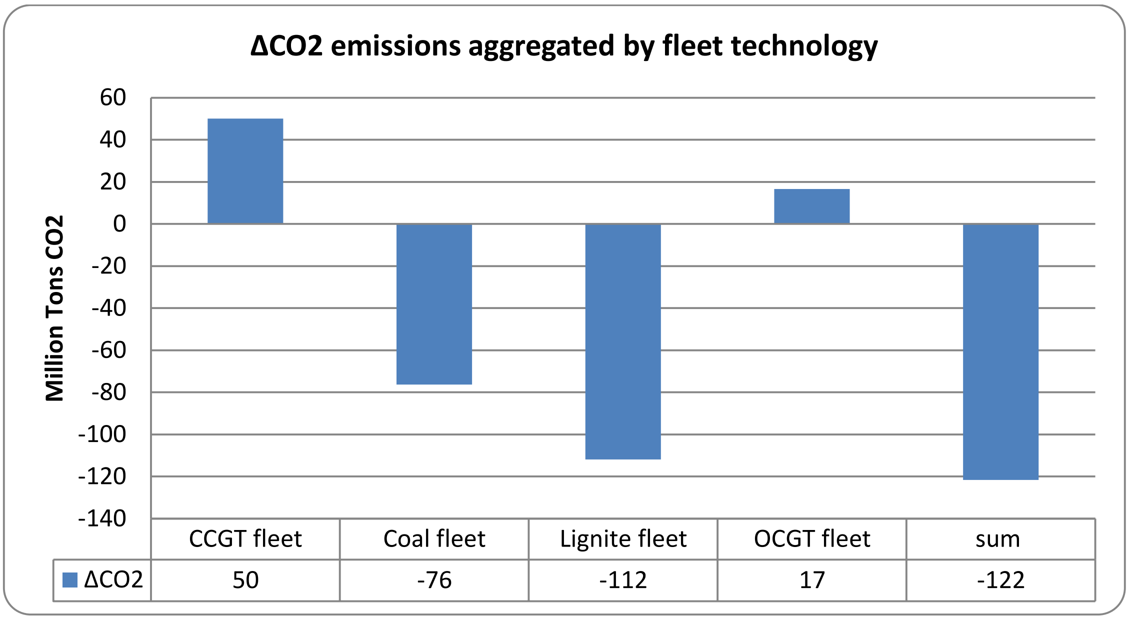


Overall in the ACD_base scenario the annual production costs are increased by 8 billion € compared to the EUCO27. It should be noted that this is the outcome under the conservative assumption that the CO_2 price remains unchanged at 38.5 €/ton CO_2. This is further discussed in paragraph 4.4.

4.3 CO_2 emissions

The CO2 emission reductions achieved by replacing coal with gas are considerable. The annual incremental change in emissions per technology is provided by the figure below.

Figure 15 Fleet CO2 emissions change in the ACD vs the EUCO27_2030 context



Overall in the ACD scenario the CO_2 emissions are reduced by 122 million tons compared to the EUCO27 scenario.

4.4 Carbon dioxide abatement cost

As evidenced above in the ACD context the coal phase-out leads to impressive CO_2 emissions reductions. However this comes at a cost, at least one part of which has been quantified in paragraph 4.2.2. The increased production cost is estimated by METIS at 8 billion €/year. Moreover the 39 GW of peaking capacity, necessary in order to restore the reliability indicators to the EUCO27 levels, would require an estimated annual investment cost (capacity cost) exceeding 1.8 billion € (assumed at 45 000€/MW-year).

Although both these cost components are paid by consumers, it may be argued that the capacity cost may not be fully considered as an incremental cost of the ACD_base scenario over the EUCO27. This is because the present analysis is static, focusing on one year and ignoring long term investment costs. The majority of the coal power plants that the ACD_base scenario considers due for retirement by 2030 will have exceeded forty years of service, requiring significant investments to keep them in operation and compliant with the applicable emission limits. These investments may be enabled through capacity payments, designed to ensure their operators' profitability. Therefore it is possible that a significant part of the capacity cost calculated above would not in reality constitute an incremental cost component of an ACD_base scenario over the EUCO27.

By using the above assumptions and discussion, the CO_2 abatement cost calculated in the ACD context is estimated to range between 65 and 80 €/ton CO_2. This value has been computed assuming the same CO_2 price as in the EUCO27. In reality however the CO_2 price will be lower in an ACD_base scenario, compared to the EUCO27. For every 1€ reduction of the CO_2 price there is a consequent cost reduction of 0.55 billion € in total costs[13]. Consequently a 13-15 €/ton reduction of the CO_2 price would, cost-wise, make this scenario equivalent to the EUCO27.

4.5 Gas consumption

One further area of interest is security of gas supply. In the ACD_base scenario gas-fired power plants are used more extensively compared to the EUCO27. Production from CCGTs and OCGTs totals 700 TWh, a 40% increase compared to the EUCO27 scenario. Although this increase may appear significant, the resulting additional gas consumption remains low compared to the total gas consumption in the EU: The ACD_base gas fired generation is 14% higher compared to the actual gas fired generation in 2016[14] (ENTSO-E, 2017) in the 34 countries while the additional gas compared to the EUCO27 is estimated at around 460 TWh GCV. This value represents 9.4% of the total gas consumption in the EU during 2016 (4973 TWh) [15]. Further analysis on the resilience of the gas system may be required to verify that peaking demand can be supplied. However, import dependency concerns put aside, the above figures suggest that the additional volumes of gas should not be particularly challenging for the European gas systems.

It is possible however that gas transmission investments are required to bring fuel to isolated areas where coal was hitherto the main fuel (i.e. Sardinia, IT).

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[13] The annual CO_2 emissions from the power sector in the ACD_base context are 550 million tons.

[14] ENTSO-E Statistical Factsheet 2016

[15] Eurostat Natural gas consumption statistics

5 ACD_res scenario results

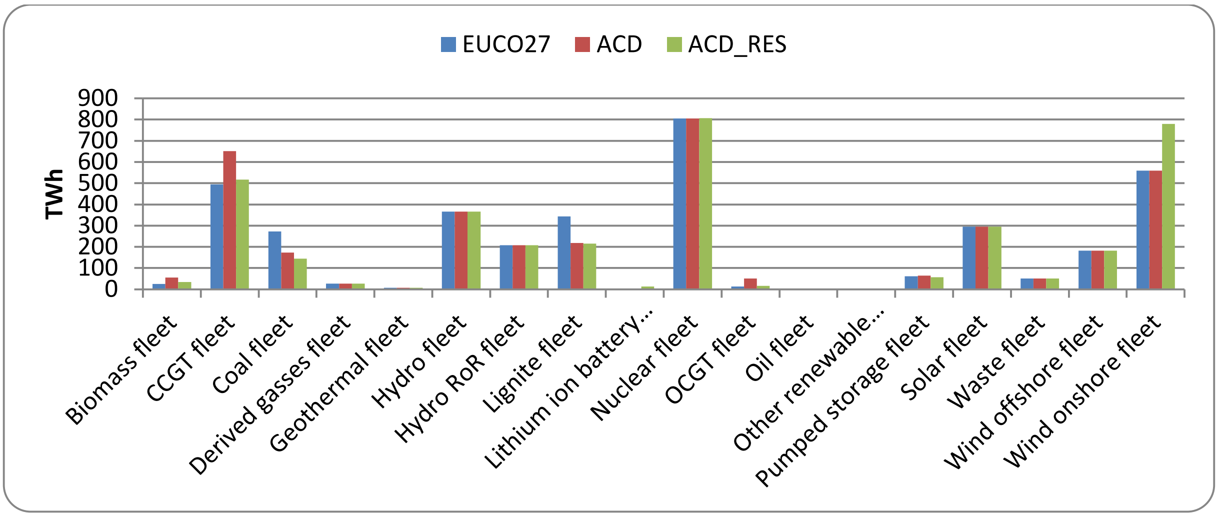
In the present section the results produced with METIS by simulating the power system optimal dispatch for one year in the ACD_res scenario are presented, highlighting the differences with respect to the ACD_base and the EUCO27 scenarios.

5.1 Power system

5.1.1 Overview of production

In the ACD_res scenario the energy deficit caused by the hard coal and lignite decommissioning is filled by onshore wind generation. The following graph provides a side by side comparison of the three contexts with regard to the electricity generated by each technology fleet across the modelled area.

Figure 16 Fleet annual production in the three scenarios



Hard coal and lignite are lower compared to the EUCO27, replaced by an increase in wind generation. This appears to be operationally possible because of the dispersion of the additional onshore wind generation assets at the EU periphery, (North, Southeast and Southwest) and is enabled by significant interconnection capacity upgrades totalling 55 GW, as presented in paragraph 3.5.2.2.

5.1.2 Marginal cost

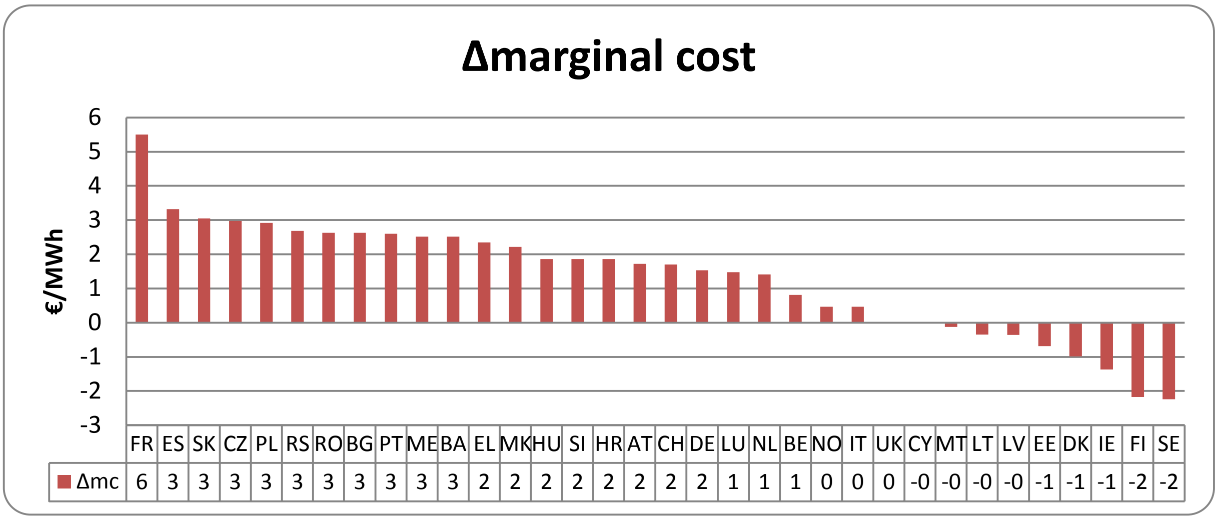
The average marginal cost, computed by METIS, in the ACD_res scenario is somewhat higher (1.4€/MWh) compared to the EUCO27. Distinguishing between the effect of adding onshore wind and adding interconnectivity is not straightforward. In principle the resulting marginal cost differences should be the combination of two effects: onshore wind pushing marginal cost downwards and interconnection upgrades reducing the price divergence between neighbouring countries. This is exemplified by the marginal cost time series average and standard deviation values provided in the table below:

Table 5. Average and standard deviation values of the marginal cost (€/MWh)

Scenario	**average**	**σ**
EUCO27	68.5	5.4
ACD_base	74.7	6.8
ACD_res	69.9	4.7

The marginal cost changes in each country in the ACD_res scenario, with respect to the EUCO27 scenario, are provided in Figure 17, ranked from highest to lowest.

Figure 17 Country average marginal cost increase in the ACD_res vs the EUCO27 scenario

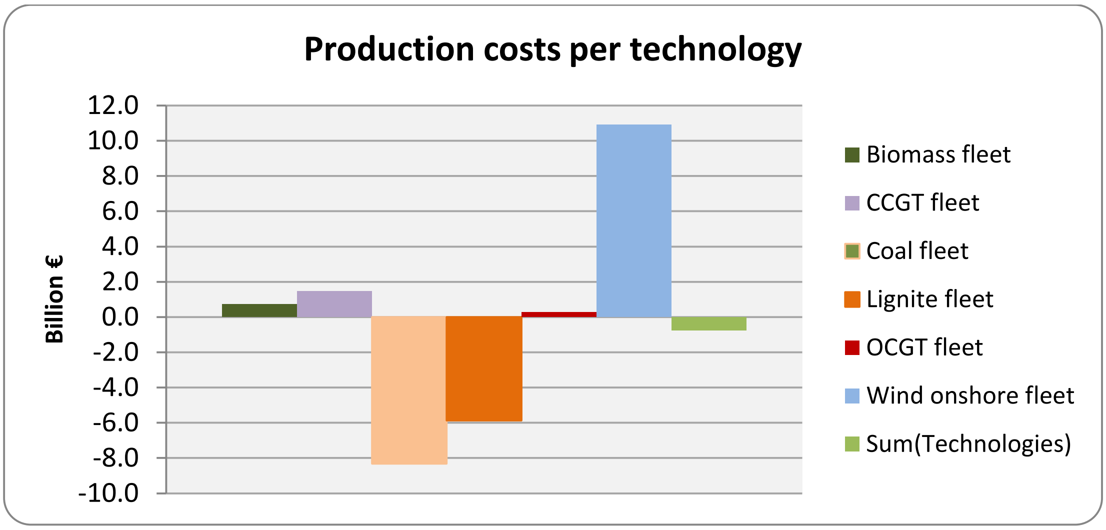


In the countries on the left hand side of the graph the cause behind the rise in the marginal cost may be located either in the enhanced interconnections (EL, ES, PT, and FR) with neighbours exhibiting higher prices and/or in the retirement of coal capacity. In the countries on the right hand side of the graph we interpret that the driver is the onshore wind generation increase (FI, SE) and/or the interconnectivity with neighbours with lower prices (UK, IE).

5.1.3 Production cost

The production cost presented below comprises all variable costs plus fixed operating costs, but not investment costs, for all technologies except for the additional onshore wind. Capex of the additional onshore wind is included. The figure below provides the changes in the overall production costs at fleet level.

Figure 18 Fleet production cost change in the ACD_res vs the EUCO27 scenario

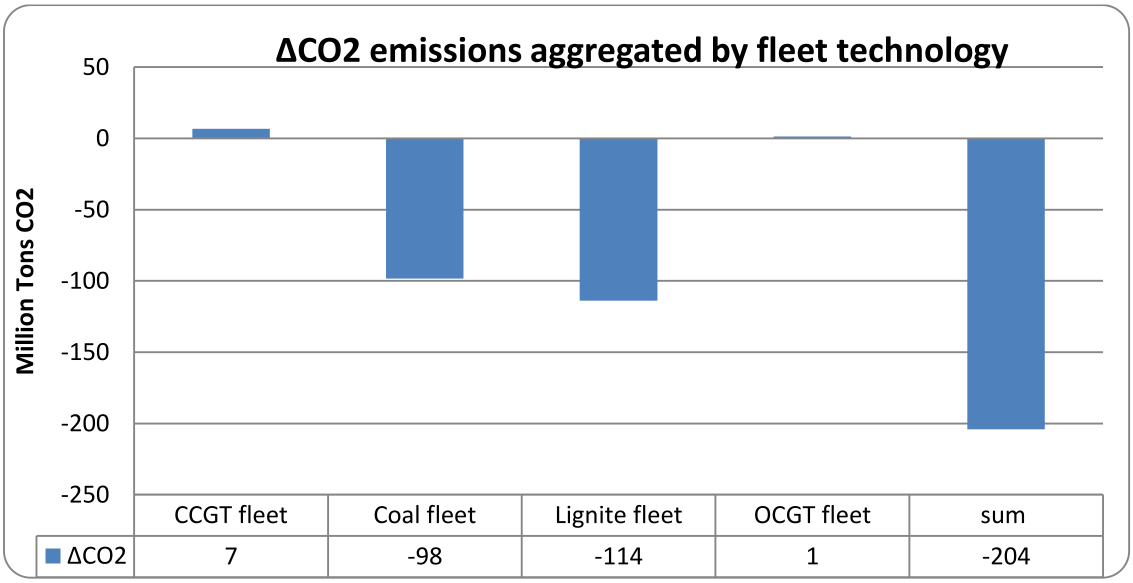


Generation cost-wise, the ACD_res scenario appears somewhat more economical (-0.7 billion €) when compared to the EUCO27. However this scenario assumes large transmission capacity upgrades (55GW) of the European transmission network, entailing significant associated costs, not included in the above calculations. The costs associated with possible real transmission grid investments, required to enable power to flow between regions, as modelled in this scenario is beyond the scope of the present analysis. However in the following paragraph 5.3 an indication is provided on what could be considered as an upper bound of investments on transmission line upgrades to support the ACD_res scenario as presented in this document.

5.2 CO_2 emissions

The figure below provides the CO2 emission reductions per technology in the ACD_res scenario.

Figure 19 Fleet CO_2 emissions change in the ACD_res vs the EUCO27 scenario



	CCGT fleet	Coal fleet	Lignite fleet	OCGT fleet	sum
■ ΔCO2	7	-98	-114	1	-204

Overall in the ACD_res scenario the CO_2 emissions are reduced by 204 million tons compared to the EUCO27 scenario.

5.3 Transmission upgrade annuity vs Carbon dioxide abatement cost

In the ACD_res scenario the coal phase-out leads to even more impressive CO_2 emissions reductions. The production cost is estimated by METIS slightly below the EUCO27 scenario -0.7 billion €/year. Estimating the carbon dioxide abatement cost through the implementation of the ACD_res scenario would require knowledge of the investment for realising the 55 GW of transmission capacity, necessary to guarantee the flow of wind generation produced in the periphery towards central Europe.

Instead, we reverse the calculation to estimate, based on the presented work, what may be considered as an upper bound of the annuity of cost-effective investments on transmission upgrades, required to enable the realisation of the ACD_res scenario as presented in this document. This value, equal to averted costs due to the abated emissions of CO_2 (at EUCO27 price), is 8.6 billion €[16] - annually.

When factoring in the unaccounted for investment in li-ion batteries (0.9 billion€/year[17]) this value adjusts to slightly above 7.7 billion € annually.

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[16] It is the product of 204 million tons abated at a price of 38.5€/ton plus 0.7 billion € due to reduced production costs in the ACD_res

[17] Calculated as the product of 15 GW with a capex set at 57 000€/MW-year

6 Conclusions and further work

METIS was used to analyse the feasibility of significant coal phase-out taking place by 2030, drawing the following conclusions:

- The EUCO27 scenario could be tweaked to accommodate a much faster (double) coal phase-out rate by 2030. The phase-out is technically possible in the two very different scenarios analysed:
    1. The **ACD_base** scenario, relying on conventional peaking capacity.
        - Existing CCGTs, running on natural gas, would fill most of the energy deficit.
        - New peaking capacity would be required to fill the capacity deficit. In our non-optimal analysis (OCGTs are used as peaking units).
    2. The **ACD_res** scenario, which would rely on onshore wind power generation, interconnections and a limited amount of storage.
- The **ACD_base scenario** would incur significant incremental costs, if CO_2 prices remained constant. These costs would not be equally distributed. Some countries (Central Europe and the Balkan Peninsula) would face higher marginal price increases than others (Iberian Peninsula and France).
- Although the level of CO_2 abatement is significant, the abatement cost of the **ACD_base scenario** is estimated to range between 65 and 80 €/ton CO_2.This result indicates that the ACD_base scenario is feasible but costly, when considering zero impact to the EUA price (constant at 38.5€/ton). However the base scenario could be virtually cost neutral, compared to the EUCO27, if CO_2 prices reduced by 13 €/ton CO_2 or more as a result of emission reductions achieved by the power sector.
- The additional volumes of gas required in the **ACD_base scenario** are significant compared to the EUCO27, but not alarmingly so when compared to current levels of gas consumption.
- The **ACD_res scenario** on the other hand leads to very high CO2 abatement: 204 million tons/year, while operating costs are marginally lower compared to the EUCO27.
- However a necessary condition for the **ACD_res scenario** is the realization of significant transmission upgrades. The required inter-node NTC upgrades total 55 GW of additional capacity.
- Estimating the cost of the upgrades is beyond the scope of the present analysis. However an outcome that could possibly be compared with, and referenced in other similar studies, is the upper bound of the annuity of the transmission investments that could be considered as cost-effective for enabling the **ACD_res scenario.** This value is calculated just above 7.7 billion €/year. This estimate is based on the assumption that the highest acceptable limit of abatement cost is equal to the EUCO27 CO_2 cost (38.5€/ton CO_2).

6.1 Possible further work

Further research is deemed useful possibly along some or all of the following paths:

- Analysis of the **ACD_base scenario** in an energy model like JRC-EU-TIMES[18], or POTEnCIA[19], in order to endogenously calculate the EUA price reduction potential, due to the achieved CO_2 emissions reductions.

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[18] https://ec.europa.eu/jrc/en/scientific-tool/jrc-eu-times-model-assessing-long-term-role-energy-technologies

[19] https://ec.europa.eu/jrc/en/potencia

- Further research into the detailed upgrades required to achieve the transmission capacity modelled in the **ACD_res scenario**, as well as their associated costs.
- An alternative **ACD_res scenario,** comprising of limited interconnection enhancements and hydro pump storage alongside li-ion batteries.
- Assessment of the gas system capacity adequacy and resilience in the case of the **ACD_base scenario**.
- Adequacy assessment of the 2 scenarios for more climatic year data, based on multiple sources.
- Investigation of the thermal efficiency improvements and consequently CO_2 emissions reduction by the higher utilisation of the thermal assets in the **ACD_base scenario**.

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List of abbreviations and definitions

ACD_base	Accelerated coal decommissioning context with thermal peaking capacity
ACD_res	Accelerated coal decommissioning context with renewable capacity and interconnections
Capex	Capital expenditure
CCGT	Combined Cycle Gas Turbine
EUA	European Emissions Allowance
li-ion	Lithium-ion battery technology
NTC	Net transfer capacity
OCGT	Open Cycle Gas Turbine
TYNDP	Ten Year Network Development Plan

List of figures

List of tables

Annexes

Annex 1. Coal and lignite fleets in the 2030 ACD scenarios

Table 6. Coal and lignite fleets in the 2030 ACD scenarios

Country	Hard coal MW	Lignite MW	Total MW	Change % compared to the EUCO27	Change MW compared to the EUCO27
AT	0	0	0	-100%	-776
BG	0	670	670	-79%	-2589
CZ	800	3836	4636	-47%	-4091
EE	0	1364	1364	0%	0
EL	0	949	949	-67%	-1888
HR	500	0	500	-24%	-157
HU	0	0	0	-100%	-374
PL	7070	4860	11930	-40%	-7804
SI	0	600	600	-5%	-32
FI	0	0	0	-100%	-1784
DE	16589	7090	23679	-35%	-13031
RO	0	990	990	-48%	-919
SK	0	0	0	-100%	-459
SE	0	0	0	-100%	-128
ES	3943	0	3943	0%	0
GB	0	0	0	-100%	-6389
AT	0	0	0	-100%	-776
BE	0	0	0	0%	0
DK	0	0	0	-100%	-1472
FR	0	0	0	-100%	-191
IE	0	0	0	-100%	-842
IT	0	0	0	-100%	-5098
LV	0	0	0	0%	0
NL	0	0	0	-100%	-5054

Annex 2. Technology data used in the capacity expansion

Table 7. Technology data used in the capacity expansion

Technology	Capex €/MW-Year	Technical data
OCGT	59 500	Efficiency : 39% (HHV)
Onshore wind–North	127 000	Load factor : 25.4%
Onshore wind–South	127 000	Load factor : 30.2%
Solar capacity	67 600	
Lithium ion battery storage	57 000	Discharge time : 2 h

The values in the table above are taken from the EUCO27 scenario. The capex of li-ion storage is derived from (Schmidt, 2017). The cost assumption 244 €/kWh (8% discount rate is applied for 15 years: 28500€/MWh – year). This value is above the SET Plan technical targets for a battery based energy storage system cost in 2030 (European Comission, 2016). We defined the capex costs for a system with 2 hours discharge time as this led to maximal penetration of the technology.

Annex 3. Parametric expansion runs

Capacity expansion runs in a single zone model

The following table contains the additional capacity required to limit lost load occurrences to equal or less than 4 hours per year when considering the EU area plus Norway and Switzerland as one zone. New wind and solar capacity is added in increments of 50 GW up to a total of 100GW, while a mix of 80:20 is also provided to showcase the lack of effectiveness of solar energy in restoring adequacy. In run #7 adequacy is restored in the single zone model by introducing additional carbon free technologies: 96 GW of onshore wind and 19 GW of li-ion storage and is the resulting run of a fine tuning process to identify the technology mix with the highest effectiveness in replacing OCGTs (lowest value of Ratio[i]). The column ΔCost provides the difference in the cost function of each run compared to run #0.

Table 8. Capacity expansion runs in a single zone model

Run	Capacities in GW								%thermal	Ratio(i)*	ΔCost billion €
	OCGT	ΔOCGT	Wind	Δwind	Solar	Δsolar	Li-ion storage	ΔCapacity			
0	84.5	37.5	240	0	231	0	0	37	101.6%	-	-
1	63.2	16.2	290	50	231	0	13	79	20.5%	3.70	-2.1
2	47.0	0.0	340	100	231	0	17	117	0.0%	3.11	-3.9
3	53.6	6.6	320	80	251	20	15	122	5.4%	3.94	-3.5
4	76.5	29.5	240	0	281	50	14	93	31.8%	11.54	-0.8
5	72.4	25.4	240	0	331	100	19	145	17.6%	11.92	-1.4
6	49.3	2.3	330	90	231	0	18	110	2.1%	3.12	-3.6
7	47.0	0.0	336	96	231	0	19	114	0.0%	3.04	-3.8

* Ratio(i) of carbon free capacity in run [i] to open cycle gas turbine addition (ΔOCGT) in run [0]: This ratio effectively provides an indication of the carbon free capacity which is equivalent to 1 MW of OCGT in terms of ensuring adequacy.

Capacity expansion runs in a two zone model

The next step was to assess with a rough spatial optimisation of the wind location with the highest effect on system adequacy. This was implemented by conducting an optimisation run for the European power system split in two zones (north and south). The results are provided in Table 9 in the following page.

Table 9. Capacity expansion runs in a two zone model

Run	li-ion	OCGT	ΔOCGT	Interconnection	ΔInterconnection	Δwind-S	Δwind-N	ΔCost Billion €
	GW							
0	0.0	88.1	41.0	15.9	0.0	0.0	0.0	0.0
1	12.6	77.5	30.4	24.9	8.9	0.0	0.0	-0.6
2	15.2	47.2	0.1	52.1	36.2	75.0	0.0	-6.5
3	12.6	60.7	13.6	25.2	9.3	0.0	75.0	-2.4
4	10.9	54.1	7.0	42.5	26.5	50.0	25.0	-5.2
5	14.9	55.4	8.3	32.2	16.3	25.0	50.0	-3.8

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