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## Phasing out coal - An impact analysis comparing five large-scale electricity market models

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# **Phasing out coal - An impact analysis comparing five large-scale electricity market models**

*by*

Arne Pöstges<sup>1,\*</sup>, Michael Bucksteeg<sup>1</sup>, Oliver Ruhnau<sup>2</sup>, Diana Böttger<sup>3</sup>, Markus Haller<sup>4</sup>, Eglantine Künle<sup>5</sup>, David Ritter<sup>4</sup>, Richard Schmitz<sup>3</sup>, Michael Wiedmann<sup>5</sup>

<sup>1</sup> *House of Energy Markets and Finance, Germany*, <sup>2</sup> *Hertie School, Berlin, Germany*,  
<sup>3</sup> *Fraunhofer Institute for Energy Economics and Energy System Technology IEE, Kassel, Germany*, <sup>4</sup> *Oeko-Institut e.V., Freiburg, Germany*, <sup>5</sup> *Institute of Energy Economics at the University of Cologne (EWI), Cologne, Germany*, \* *corresponding author*  
([arne.poestges@uni-due.de](mailto:arne.poestges@uni-due.de))

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## Abstract

Climate target achievement has a crucial influence on the modelling and the decision processes in the energy sector. It induced the development of several policy instruments to mitigate greenhouse gas emissions, including administrative and market-based mechanisms for phasing out coal-fired generation technologies. In order to analyse such instruments, electricity market and energy system models are widely used. However, results and corresponding recommendations largely depend on the formulation of the respective model. This motivates a systematic comparison of five large-scale electricity market models which are applied to European scenarios considering the period until 2030. An evolved diff-in-diff approach is proposed to analyse the effects of two coal phase-out strategies. This contribution expands on that of earlier studies and provides some more general takeaways for both modellers and decision-makers. For instance, the evolved diff-in-diff analysis shows the influence of the reference scenario when evaluating a policy instrument. Furthermore, the importance of technical aspects such as constraints for combined heat and power plants are discussed and implications regarding three dimensions (economic, environmental, and security of supply) are presented.

**Keywords:** model comparison, coal phase-out, electricity market model, energy policy



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# 1 Introduction

The provision of clean energy under ambitious climate targets is one of the main challenges in the decades ahead. In Europe, the decided Green Deal aims at climate neutrality by 2050 (cf. European Commission 2019). In the power sector, this is mainly implemented through the European Emission Trading Scheme, while being complemented with different national policies, e.g., renewables support mechanisms and phase-out plans for fossil-fired generation (cf. e.g., Kitzing et al. 2012 and Anke et al. 2020).

Since coal is still one of the primary energy sources in the electricity sector in several European countries (cf. Eurostat 2020), coal phase-outs are a straightforward and direct measure to reduce CO<sub>2</sub>-emissions. While many European countries have already decided to phase-out coal (PT, SK, FR, IT, IE, HU, GR, ES, DK, FI, NL, DE) and some others are currently discussing a phase-out (SI, PL, CZ), there are only three countries where phase-out plans are currently not on the political agenda or even investments in new coal plants are possible (RO, BG, HR) (cf. European Commission 2021)<sup>1</sup>. Independent of the current state of the political process, the discussion on coal phase-outs is far from over in all countries which have not yet completed it. Even if already decided, phase-out implementation is subject to ongoing evaluation and discussions, not least because of the tightening of climate targets at the European level. Likewise, higher European targets increase the pressure on countries that not yet have coal phase-out plans to put such plans on the agenda. This and also ongoing debates in countries outside of Europe underline the relevance of a coal phase-out as a policy instrument (cf. e.g. Climate Transparency 2019).

Debates on coal phase-outs are often supported by model-based analyses. For the example of Germany, such studies draw a differentiated picture of the implementation of a national coal phase-out. Some studies assume that the coal phase-out will be completed by 2030 (e.g., Kopiske and Gerhardt 2018), while others assume longer periods. In some studies, lignite and

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<sup>1</sup> SE, AT, LU, CYP, MT, EE, LV, BE, LT are already coal-free as of 2021,

hard coal capacities are reduced equally (e.g., Agora Energiewende 2016), while in other scenarios lignite has to contribute significantly more to emission reduction (e.g., Horst et al. 2015). Besides capacity reductions, (Matthes et al. 2017) compare further instruments like higher CO<sub>2</sub> prices and emission caps. Given their different approaches and backgrounds, these studies consider quite heterogeneous installed coal capacities, as shown for the year 2030 in Figure 1.

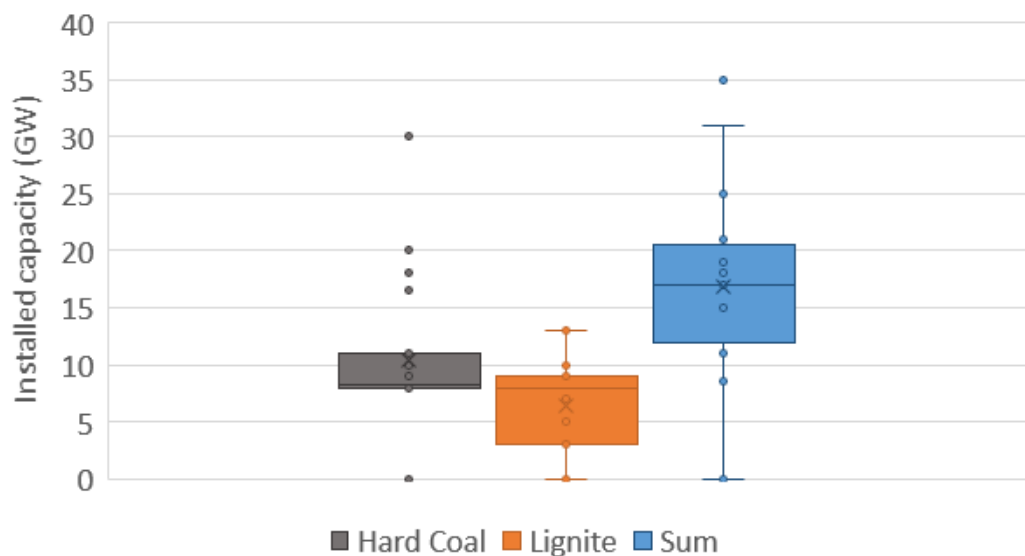


Figure 1: Overview of installed coal capacities in Germany in 2030 in various scenarios. Sources: Horst et al. (2015), Agora Energiewende (2016), Göke et al. (2018), Kopiske and Gerhardt (2018), Agora Energiewende and Aurora Energy Research (2019), Oei et al. (2020), Gierkink, Lencz, and Arnold (2020), Harthan et al. (2020), Kemmler et al. (2020), Hermann, Hauke et al. (2017)

The studies do not only vary in terms of phase-out plans and scenarios but also modelling approaches. For instance, the market modelling might be based on dispatch or investment models, the latter considering an endogenous investment in and decommissioning of generation units. Other differences typically arise regarding the implementation of combined heat and power plants (CHP), flexibility options, the countries considered (further referred to as “geo scope”), the weather year or the calculation of indicators such as emission balances or cost factors. Peer-reviewed publications left apart, these characteristics and their impact on results are neither published with great detail nor discussed in the examined studies.



Hence, the impact of this broad range of assumptions and methodologies on the results and policy implications has yet remained unclear. To address this gap, this contribution analyses in detail two German coal exit pathways with five different dispatch and investment models.

Beyond the topic of coal phase-outs, electricity market and energy system models are widely used to support decision processes in the energy sector. Examples comprise investment decisions in companies, system planning in utilities (cf. Ioannou, Angus, and Brennan 2017) or decisions on policy reforms (Zouros, Contaxis, and Kabouris 2005). Differences in the model results, as we have illustrated in the above example of the German coal phase-out are also common in various contexts.

To better understand and reduce differences in model results, previous studies have compared such models. For example, evaluation of climate models is quite common as implemented in the IPCC assessment reports (Flato et al. 2014). Moreover, so-called “Model Inter-comparison Projects”, such as the Japan model intercomparison project, present general model comparison exercises on long-term climate policy (cf. Weyant and Kriegler 2014). Further well-known experiments with a focus on the energy sector are the Stanford Energy Modeling Forum (EMF) and the China Energy Modeling Forum (CEMF). The latter established a model comparison and exchange platform hosted by Tsinghua University, which includes a broad range of energy system models with both general and partial equilibrium models (cf. Lugovoy et al. 2018). Further model experiments were carried out within the Forum for Energy Models and Energy Economic Systems Analysis in Germany between 1997 and 2007. The closest to this paper is the experiment “Modelexperiment II” (MEX2) on nuclear power exit (cf. Fahl and Forum für Energiemodelle und Energiewirtschaftliche Systemanalysen in Deutschland 2002). More recent studies focus on policy instruments, such as the research project “Research Network for the Development of New Methods in Energysystem Modeling” (4NEMO). In this project, model characteristics have been discussed regarding their capability to depict policy instruments (cf. Savvidis et al. 2019), and model results for a common input database have been compared (Siala et al. 2020). Model experiments have been carried out under conditions

that allow transparent comparison of the modelling approaches and thus link the differences in the model calculations' results with the model properties.

However, none of these studies focused on coal phase-outs, which is a relevant research gap in view of the ongoing debate on coal phase-outs and the large differences in the results of various analysis.

We aim to fill this gap by analysing strategies for phasing out coal-based electricity generation using the example of Germany in the context of the European power system. We perform a systematic comparison of five large-scale electricity market models that are applied to two European scenarios with different coal phase-out strategies, whereby one strategy is based on the age of coal plants and the other considers economic criteria. The added value of the model comparison and the proposed methodology is twofold. On the one hand, the proposed diff-in-diff approach and its application represents an innovation in the context of model comparisons and allows identifying model-related methodological takeaways. On the other hand, the considered case study provides new insights regarding the impact of modelling approaches on the evaluation of policy instruments.

Our findings on the three dimensions reliability, efficiency, and environmental compatibility of a power supply expand on those of earlier studies and provide more general takeaways both for modelers and decision makers in the energy industry and policy area. Consequently, this study provides valuable input for the evaluation and implementation of coal phase-outs not only in Europe but also internationally.

The remainder of this paper is structured as follows. The characteristics of the different models and the evolved diff-in-diff approach are documented in Section 2. Section 3 describes the data basis as well as the analysed scenarios and policy instruments. In Section 4, we present the results of the modelling experiments. Section 5 concludes with a summary of implications and an outlook on future work.

## 2 Methodology

The model comparison framework has two pillars: the first is the comparison of model characteristics, whereas the second lies in the methodology to analyse results. Hence the model characteristics and the evolved diff-in-diff approach are introduced in this Section.

### 2.1 Model characteristics

The models<sup>2</sup> compared in this experiment are DIMENSION+ (DIM), EMMA (EMM), Joint Market Model (JMM), Powerflex (PFL), SCOPE - Electricity Market (SCO\_dis) and SCOPE - Scenario Development (SCO\_inv). All but one of the models are formulated as linear optimisation problems (LP). The dispatch model SCO\_dis is implemented as a mixed-integer problem (MIP). Some of the models also consider endogenous investment and disinvestment decisions in electricity and heat production capacity (SCO\_inv, DIM, EMM).

This chapter first presents the dispatch models before turning to the characteristics of the investment models. Features which are implemented in the models but are not relevant or used in this model experiment will not be addressed (e.g., sector coupling or electricity grid modelling).

#### Modelling of dispatch

All dispatch models include the basic features of electricity market models and have many features in common. This Section highlights the differences in implementation.

The models differ in terms of spatial coverage and the detail used to implement neighbouring countries. Two models (PFL, SCO<sup>3</sup>) aggregate generation units on a higher level outside of Germany. One model (EMM) includes only 12 European countries and uses exogenous power exchanges with the non-modelled countries. Three models (EMM, JMM, SCO) simulate the provision of heat via cogeneration units outside of Germany.

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<sup>2</sup> An overview of the utilized models is given in Table 1 in Appendix A.

<sup>3</sup> In the sense of simplicity, the investment model SCO\_inv and the dispatch model SCO\_dis are put together and referred to as “SCO” from here on.

One model (JMM) implements regional heat demands, whereas the national heat demand can be provided by any plant in two other models (DIM, PFL). Two further models implement a different approach: each plant is given an exogenous heat demand to be supplied, one unit-wise (SCO), the other one vintage-wise (EMM).

Regarding the simulation approach, two models make use of rolling planning (JMM, SCO), whereas the others either optimise the full-time horizon (integrated optimisation) (EMM, PFL) or use sequential and parallel computing (DIM). Given the optimisation under perfect foresight, the different simulation approaches might cause differences in the dispatch of technologies that are subject to intertemporal constraints, e.g. storages.

In European electricity markets balancing services are usually procured on a day-ahead (sometimes week- or month-ahead) basis. Together with the spot markets, reserve power markets form an integral part of the sequential market design. The participation in both markets can be seen as an “either-or decision” leading to opportunity costs and impacting the actual dispatch of power plants. Due to their importance, frequency control markets are considered in all models, but implemented in different ways: One model (JMM) includes the reservation for both positive and negative primary (FCR), secondary (aFRR) and tertiary (mFRR) control reserves. One of the models (DIM) further accounts for the fact that the reservation for primary control has to be symmetric<sup>4</sup>. The other models implement frequency control only partially: One model (EMM) accounts for the primary and secondary reserves. A further model (SCO) accounts for secondary and tertiary reserve. One model (PFL) accounts for the reservation of a single, generic control type, which also has to be symmetric. The activation of reserves is not considered in the model experiment.

Thermal power plants’ partial efficiency and start-up costs are modelled in three of the models (DIM, JMM, SCO). Minimum operating and down-times are introduced as restrictions in two of

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<sup>4</sup> If control reserve is offered in one control direction (for instance positive), the same amount has to be offered in the other direction

the models (JMM, SCO). All models implement time-dependent availabilities, and all but one (EMM) implement ramping constraints.

### **Modelling of investment decisions**

The three models with endogenous investments implement very different approaches. Only one model considers all of its dispatch features when optimising investment (EMM). The others use simplified dispatch modelling, not accounting for frequency control markets (SCO) or using a different time representation (DIM). Furthermore, a significant difference arises regarding the implementation of the intertemporal aspect of investment decisions: two models (SCO, EMM) use a dynamic recursive approach with new investments computed separately for the consecutive scenario years without anticipation of future developments. By contrast, the other (DIM) computes the investments over the time horizon from the start year towards the target year as a pathway. For computational reasons, this model optimises the dispatch and investment of given years - represented via typical time periods - within the time horizon and interpolates the other years.

The assessment of investments is based on global and constant discount rates for all models. Nevertheless, the models take a different perspective with regards to the refinancing of investments. While DIM assumes a macroeconomic approach associated with a (lower) social discount rate, the other two models consider a private discount rate. Moreover, all investment models include endogenous investments for all technologies (including renewables). However, endogenous decommissioning is by default only allowed in EMM and DIM and not in SCO.

## **2.2 Evolved diff-in-diff approach**

The analysis of results by comparison to a baseline is widely used in the field of electricity market and energy system optimisation. Nevertheless, such work often lacks the fundamental description of the comparison. To structure the comparison of model results, we propose an evolved diff-in-diff approach.

The difference in difference (DID) is a statistical analysis technique to assess the differential impact of a treatment by comparing a group under treatment and a control group without treatment. It is, *inter alia*, frequently used in experimental studies or policy analysis in the field of public health research and social science (Wing, Simon, and Bello-Gomez 2018). Furthermore, it has been applied in energy economics, e.g., to analyse impacts of energy efficiency measures on energy consumption (cf. Meyer 1995; Hamilton et al. 2013; Wyatt 2013) and potential effects of carbon trading (cf. Zhang et al. 2016). Causes for treatment can be new programs, interventions or policy changes. The intervention itself can be, e.g., a new vaccine in the field of public health or the implementation of carbon trading mechanisms in energy economics.

The standard approach measures the “difference in difference” (i.e. outer difference) between the group with treatment (G2) and the control group (G1), as shown in Figure 2. The first, inner difference is calculated within each group as a change in the outcomes over time, between the beginning and the end of a specific time period (inner difference of G1 and G2). For both groups, the development of the outcomes is influenced by the change of exogenous parameters over time, but only one group is additionally influenced by the effects of the treatment (cf. dotted and solid blue line in Figure 2). On this basis, the outer difference is defined as the difference between the inner differences of the treatment group and the control group to eliminate the impact of uncontrolled/exogenous effects within the analysis. Consequently, the effect of the treatment can be isolated via the different outcome of G1 and G2 in Figure 2.

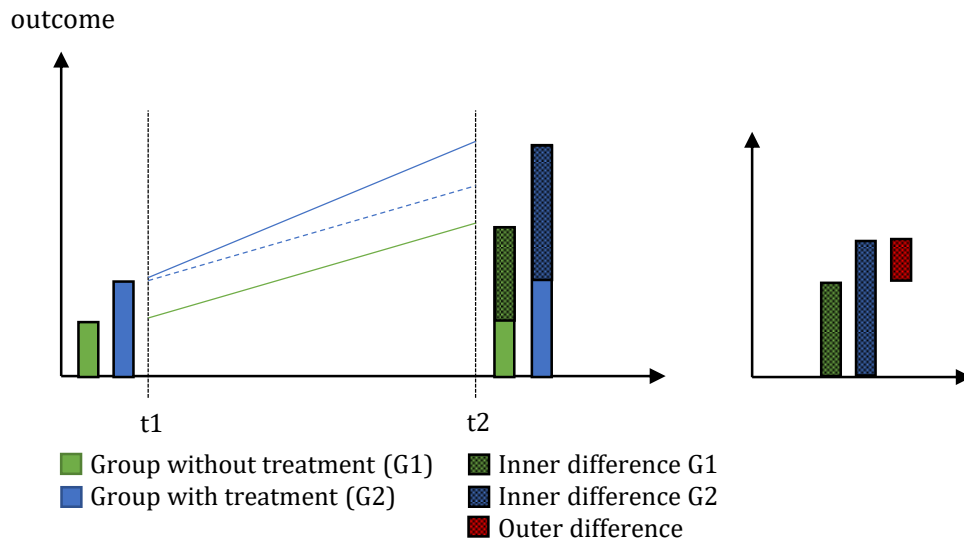


Figure 2: Standard difference in difference approach

This contribution's experimental framework is a model comparison with the implemented interventions strategies for a German coal exit. The specific intervention to be analysed is the design of the coal exit instrument (cf. Section 3). Figure 3 illustrates the application of the standard DID approach to one model and two different scenarios. The first scenario is defined as the reference or baseline scenario for the timesteps t1 (grey) and t2 (green). As the reference scenario in t2 only depends on the development over time, and no treatment is applied, it is comparable to the outcome of G2 in timestep t2 in Figure 2. A specific coal exit strategy determines the outcome of the second scenario (blue). The outer difference is subsequently determined by comparison of the inner differences of each model. Note that unlike the standard approach, Figure 3 presents a case in which only one scenario in t1 exists. This analysis is comparable to an experiment in public health: the group is split into a group under treatment and a control group.

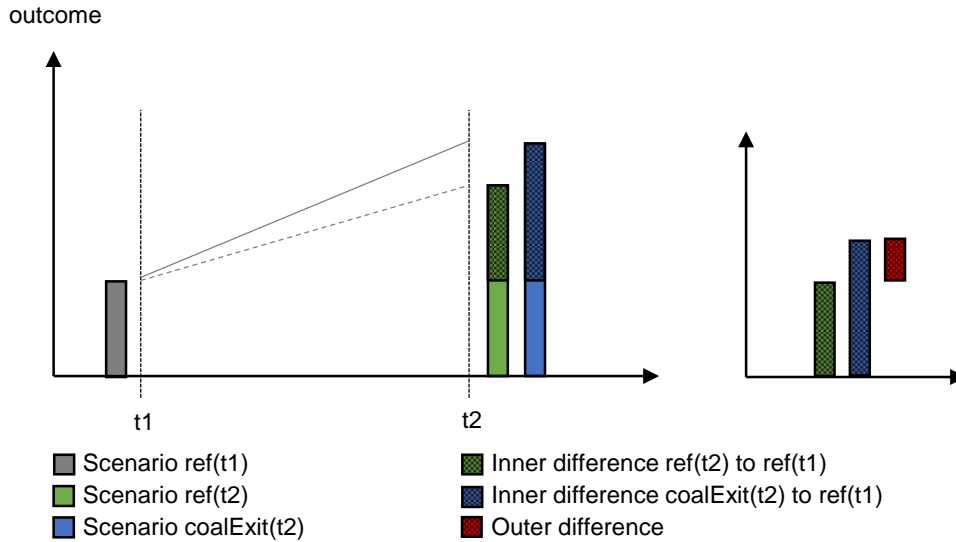


Figure 3: Standard difference in difference approach applied to the scenario framework at hand

In this contribution, the standard DID approach is evolved into a difference-in-difference-in-difference (DIDID) approach by adding one more difference to the analysis. The outer difference as a result of the standard DID approach is additionally compared to the outer differences of other electricity market models (which will hereinafter be referred to as “model difference”) as shown in Figure 4.

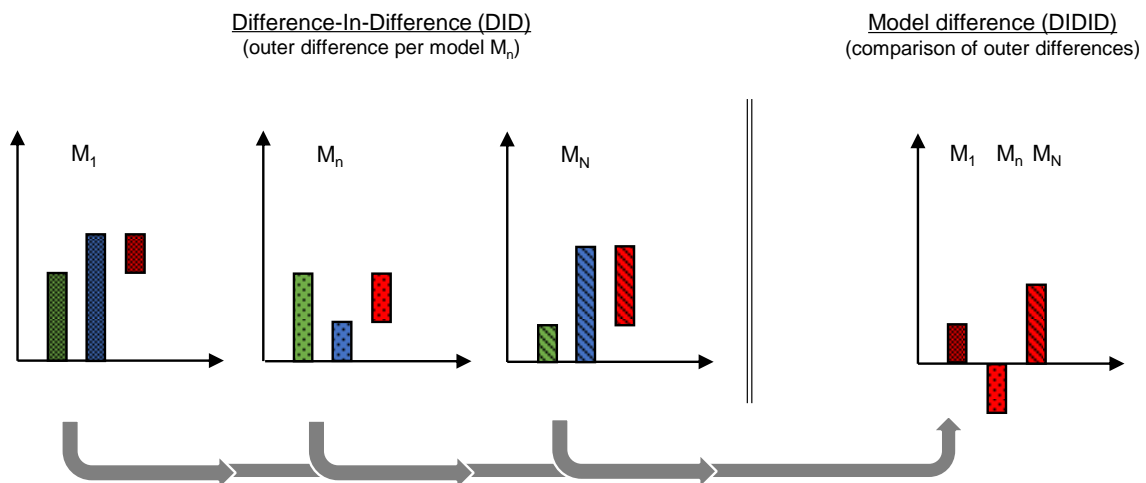


Figure 4: Modified difference in difference approach

Without the proposed procedure, the different results of the models after the intervention could be attributed to the policy instrument only partially, as the models do not have the same starting point.



While the standard DID approach isolates the effect of a policy instrument for each model, the comparison of the outer differences of multiple models (i.e. model differences) directly displays deviations in the model responses to a policy instrument. In other words: assuming harmonised inputs, varying model differences (e.g. in CO<sub>2</sub>-emissions) under one coal phase-out plan indicate deviations in the modeling approach. An example are differences caused by the modelling of endogenous investment and CHP constraints: a model with endogenous generation investments would replace decommissioned coal-fired CHP capacity by modern gas power plants. In contrast, a dispatch-only model would have to increase generation from existing coal and gas power plants to maintain heat supply. Hence, the different modelling approaches would lead to a different commitment of modern gas power plants versus existing coal and gas power plants. Which would materialize in a difference between the outer differences, i.e. model difference. The example also reflects that resulting model differences might be affected by the results of the reference scenario. If an investment model decommissions coal-fired plants already under the reference scenario, this might reduce the impact of a coal phase-out strategy. Consequently, model differences represent an interaction between model specification and policy instrument and answer the question: “How do effects (e.g. on CO<sub>2</sub>-emissions) of a coal phase-out differ depending on the modelling approach of different models?”

### **3 Data basis and scenario assumptions**

The model comparison is performed for three scenarios (ref, coalex1 and coalex2) in 2016, 2025 and 2030. In the following two sections the reference scenario and the underlying harmonized data basis (cf. Section 3.1) and the two coal phase-out scenarios (cf. Section 3.2) are presented. Most of the input data is harmonised between the models to focus on the impact of individual model formulations and modelling approaches. However, some parameters, e.g., technical parameters, are not aligned due to individual model-chains and databases.

#### **3.1 Reference scenario and data basis**

The first scenario (ref) is defined for all three years and forms the baseline of this analysis. The year 2016 provides historical weather data for all time-series like renewable infeed and demand profiles. The power demand profiles are based on ENTSO-E (ENTSO-E 2018a) and scaled to meet the 2016 national annual power consumption according to EUROSTAT (Eurostat 2018). It is assumed that power demand remains constant until 2030 (assuming that efficiency improvements compensate additional power demand caused by sector coupling). The demand for reserve power is assumed to be constant over the year and remains at the 2016 level for all periods. Feed-in profiles for solar PV, wind onshore and offshore are based on (Open Power System 2020) and scaled according to the scenario years' generation capacities. Future wind profiles are scaled such that full load hours increase while the peak is conserved, thus accounting for advanced wind turbines. Hydropower inflow per country is provided by Fraunhofer IEE based on their plant-wise database and historical weather data from ECMWF (European Centre for Medium-Range Weather Forecasts 2020).

Furthermore, two models (JMM, DIM) use the season-dependent storage filling levels (for hydro reservoirs) modelled with SCO as an input. The heat demand profiles are based on the CHP-model described in (Felten, Baginski, and Weber 2017) and (Felten 2020). The heat demand is approximated with a piecewise linear function of ambient temperatures. The heat demand for Germany includes residential and industrial heat. The temperature profiles and annual heat demand are based on (Bründlinger et al. 2018), (International Energy Agency

2018a) and (Renewables.ninja 2020). The hourly availability of generation units is modelled based on weekly availabilities. The corresponding time series are generated using a probabilistic model of the Chair for Management Science and Energy Economics at the University of Duisburg-Essen that distinguishes between forced (unplanned) and scheduled (planned) generation outages. Unplanned outages are drawn randomly. For planned outages, i.e., maintenance, seasonal impacts are considered leading to reduced availabilities during the summer period. Corresponding data and assumptions, i.e., probability and duration of planned and unplanned outage and seasonal pattern of planned outages are based on (ENTSO-E 2018b).

Moreover, scenario data, such as economic and technical parameters are harmonised. The technical lifetime of power plants is based on a statistical evaluation of (Bundesnetzagentur 2019). Assumptions concerning efficiency, investment costs, fixed costs and further variable costs are based on (Bründlinger et al. 2018). For investment decisions, the interest rate is set to 2 % in DIM, 7 % in EMM, and 9 % in SCO. Prices for fossil fuels and CO<sub>2</sub>-certificates are based on the “Current policies scenario” of the World Energy Outlook (International Energy Agency 2018b). Furthermore, a carbon support price of 20.54 EUR/t is implemented in the UK (Hirst and Keep 2018). While the exogenously set capacities of fossil power plants for the dispatch models are based on the scenarios “Best Estimate 2025” and “Sustainable Transition 2030” in (ENTSO-E 2018b), the investment models have an endogenous evolution of the power plant fleet. Decommissioning of fossil plants is either based on technical lifetime or an endogenous (dis)investment decision (DIM and EMM by default, SCO in coalex2). Furthermore, all three investment models are capable of endogenous investments in various fossil power plants (lignite, hard coal, natural gas). However, new coal power plants are only allowed in countries without coal exit plans (Bulgaria, Czech Republic, Greece, Poland, Romania, Slovenia) (International Energy Agency 2018c). Concerning solar PV and wind power, all models consider the installed capacities from scenarios “Best Estimate 2025” and “Sustainable Transition 2030” in (ENTSO-E 2018b). The investment models can increase these capacities if it is cost-efficient. All models consider the same hydropower capacities of

already realised and currently planned projects (Härtel and Korpås 2017) without the possibility of endogenous investment. The power generation from bioenergy and waste is assumed constant at the 2016 level. Market coupling and cross-border exchanges between European countries are modelled based on net transfer capacities from (ENTSO-E 2018b) and especially for Germany from (Rippel et al. 2019).

### 3.2 Coal phase-out scenarios

The second and the third scenario (coalex1/2) contain fundamental reference scenario modifications to analyse two German coal exit designs. As outlined in Section **Fehler! Verweisquelle konnte nicht gefunden werden.**, different theoretical coal phase-out strategies and designs are conceivable. Consequently, two different capacity-based approaches with varying complexity are implemented to comprehensively analyse the impact on the electricity market and emissions. Figure 5 presents the coal capacities' reduction in the naive and the endogenous coal exit scenario as compared to the reference scenario. The capacities of the reference scenario are based on the power plant portfolio in 2016 and a decommissioning of units until 2025 and 2030 with respect to the average empirical lifetime of hard coal (45 years) and lignite (50 years) power plants (Bundesnetzagentur 2019).

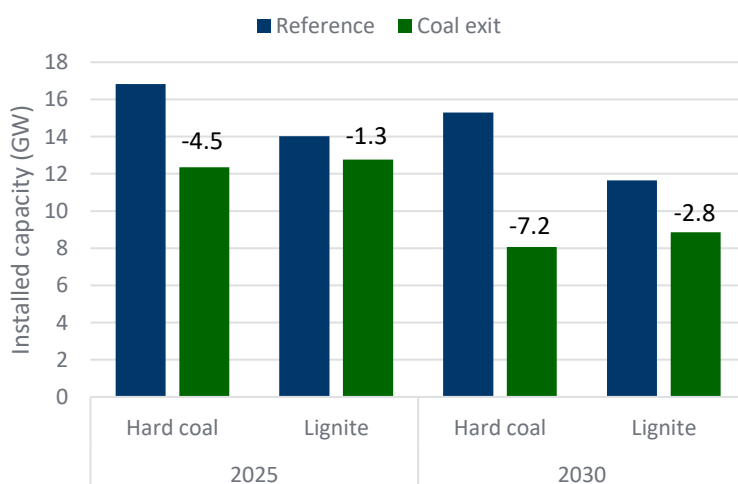


Figure 5: Reduction of coal capacities between the reference and the coal exit scenarios

Within the first “naive” approach (coalex1), the shutdown of power plants is based only on the commissioning date of each unit. The second “endogenous” approach (coalex2) is based on

the power plants' profitability. As not all participating models include endogenous capacity expansion, this approach needs to be differentiated for models with investment (i.e. DIM, EMM, SCO) and pure dispatch models (i.e. JMM, PFL).

The first approach deliberately ignores complicating effects, i.e. especially CHP constraint. It sets the benchmark for other, more complex approaches as it is the most straightforward capacity reduction mechanism. Nevertheless, this simple reduction of coal capacities is in line with the reduction targets proposed by the German Coal Commission<sup>5</sup>. Furthermore, the emission certificates price is assumed constant, which can be interpreted as resulting from the cancellation of the decommissioned coal capacities' emission certificates. This cancellation should avoid the so-called waterbed effect resulting from a lower CO<sub>2</sub> price in neighbouring countries.

The second approach also forces the reduction of coal capacities towards the German Coal Commission targets. In contrast to the first approach, the shutdown is based on the profitability of each unit. Models with endogenous decommissioning implement this mechanism with a capacity restriction. These models hence endogenously assess the value of each power plant and shut them down according to the cost-minimal solution. While SCO usually does not include the option to decommission power plants endogenously, this possibility was implemented solely for this scenario and only for coal power plants in Germany<sup>6</sup>. The dispatch models need to reduce the coal capacities iteratively. The results of the reference run determine the unit-specific contribution margin. The units are then decommissioned from the lowest to the highest contribution margin until the coal commission target is reached. The calculation includes the contribution margin on the electricity, the reserve and the heat market.

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<sup>5</sup> Note that the commission acknowledges the necessity of security of supply for heat but does not formulate further details regarding the decommissioning of combined heat and power plants.

<sup>6</sup> All other power plants as well as all coal units outside of Germany can not be decommissioned endogenously in this scenario.

## 4 Results and discussion of model differences

This Section details and discusses the model results for Germany. The results are based on model runs for three scenarios (ref, coalex1 and coalex2) over three years (2016, 2025 and 2030), based on the descriptions in Section 3. First, a comprehensive overview of the reference scenario results in the base year 2016 is provided in Subsection 4.1. In Subsection 4.2, the future development of the reference scenario is analysed by the comparison of the inner differences. Subsection 4.3 presents the analysis of both coal exit scenarios as outer differences. The structure of each Subsection is based on the key indicators presented in Table 5 in Appendix B. The discussion focuses on relevant deviations between the models.

### 4.1 Reference scenario 2016 (absolute values)

This Section presents and compares the model results in the base year 2016.

#### Generation and net import

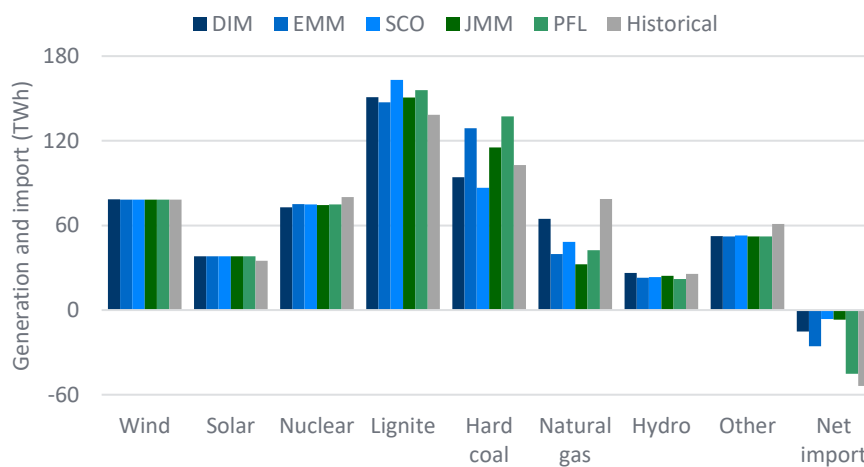


Figure 6: Annual electricity generation and net import (base year 2016)

Figure 6 presents the annual electricity generation of each model in Germany per fuel type. The category “hydro” summarises the generation from water reservoirs, run of river and pumped storage plants while “other” consists of bioenergy, oil, waste and further undefined miscellaneous generation. The historical 2016 production is provided for perspective, even though the input data for the base year was not designed to match the historical production

precisely. Hence, deviations from the historical data are not generally discussed but serve as a comparison.

The production of wind, solar, hydro, and other is exogenous to a large extent and therefore matches almost entirely across the different models. Deviations in nuclear power plant generation are also negligible. Due to their low marginal cost and high start-up/ramping costs, the simulated nuclear power output is nearly constant.

Considerably larger deviations are observed for hard coal, natural gas, and – to a smaller extent – lignite. These differences in generation occur despite almost homogenous capacity and availability assumptions<sup>7</sup> and will hence be mainly due to different model implementations. These implementation differences leading to these differences are discussed in the following.

Heat and power cogeneration is the leading implementation difference across the models. For example, differences in the allocation of heat demand (regional aggregation versus consideration of local heat networks) affect the restrictions on the operation of CHP units and the corresponding electricity output. In the case of PFL, the relatively high generation from coal-fired units might be driven by the country-wise aggregation of heat demand leading to a supply of heat preferably by cheap coal units than gas units. The extent of such a substitution is limited in models considering local heat networks (SCO and JMM) or constraining single CHP units (EMM). Moreover, in SCO lignite CHP is driven by higher generation availabilities and in DIM the low hard coal generation (relative to the other models) can partly be attributed to the fact that DIM assumes all hard coal-fired CHP plants to be extraction condensing turbines.

The implementation of frequency control reserves further varies among the models. This drives model deviations in gas and coal production through the spinning control condition. DIM implements a spinning condition for all types of plants and reserve, but CHP plants are not allowed to provide reserves. As a result, non-CHP gas power plants are standing by for the

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<sup>7</sup> There are two exceptions to homogenous capacity and availability assumptions: endogenous investment in DIM even in the base year, which we yet find to be negligible; and higher availability of CHP units in SCO, which we discuss along with the different CHP implementations.

provision of reserves, driving up the gas power production. In contrast, PFL assumes that reserves can also be supplied by CHP plants which could be one driver for the lower gas production. In JMM and SCO, a high share of the reserve is provided by pump storage plants, which also limits the reserve provision from natural gas as compared to DIM.

Differences in the implementation of technical restrictions generally have the potential to influence model results but are challenging to trace and expose. Within the group of models, JMM and SCO consider the largest number of technical restrictions followed by DIM, PFL, and EMM. Possible restrictions include ramping and start-up constraints as well as minimal output constraints. However, the influence of corresponding constraints is expected to have a comparatively low effect on the generation quantities of baseload and mid-merit plants (in case of the relatively low penetration of variable RES in 2016).

The variations in the net import generally reflect the variations in the total generation. Consequently, deviations between the models can be mainly attributed to the modelling of CHP restrictions in Germany but also neighbouring countries.

### Base price, variable costs and CO<sub>2</sub>-emissions

Figure 7 presents the costs and CO<sub>2</sub>-emissions resulting from the above generation mix.

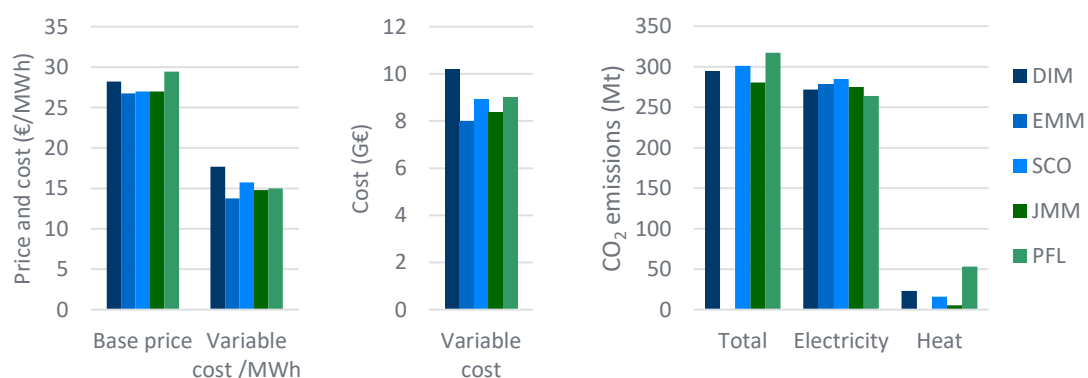


Figure 7: Economic indicators and CO<sub>2</sub>-emissions<sup>8</sup> (base year 2016)

The base price is relatively homogenous at a level of about 27 €/MWh for EMM, JMM and SCO, somewhat higher for DIM with about 28 €/MWh and highest for PFL with a price of about

<sup>8</sup> Note that EMM reports emissions only for electricity generation since heat provision is not modelled explicitly but considered by restrictions of the electricity generation.



29 €/MWh. As compared to the base price, both the overall and the per-MWh variable costs are more heterogeneous. However, this is mostly due to high variable costs in DIM, which can be attributed to the high electricity generation with natural gas.

Moreover, the total CO<sub>2</sub>-emissions vary quite substantially, but most of this variation can be attributed to heat production as compared to electricity. This once more highlights the differences in model implementations related to the cogeneration of heat and power: PFL shows the highest CO<sub>2</sub>-emissions attributed to heat, which might be driven by the relatively high generation from coal-fired CHP plants, as discussed above. For simplicity, we focus on electricity-related CO<sub>2</sub>-emissions in the following.

## **4.2 Reference scenario 2025 and 2030 (inner differences)**

The model results for the scenario years 2025 and 2030 are depicted as inner differences. The key indicator values for the scenario years 2025 and 2030 are therefore no absolute values, but differences to the 2016 values (cf. right-hand side of Figure 3).

### **Generation and net import**

The inner differences of the annual electricity generation and net import are displayed in Figure 8 for both 2025 and 2030. The increase in wind and solar generation compared to 2016 matches almost perfectly for all models, except for a slightly higher wind generation for DIM in 2025. The difference in DIM is in line with the endogenous wind investment in this model, which might be triggered by multiple factors. On the one hand, DIM's lower interest rate pushes capacity expansion. On the other hand, wind power contributes 5 % of its installed capacity to the minimum capacity restriction implemented in DIM. DIM is also the only model implementing an intertemporal optimisation. High prices in the future trigger the investments in 2025.

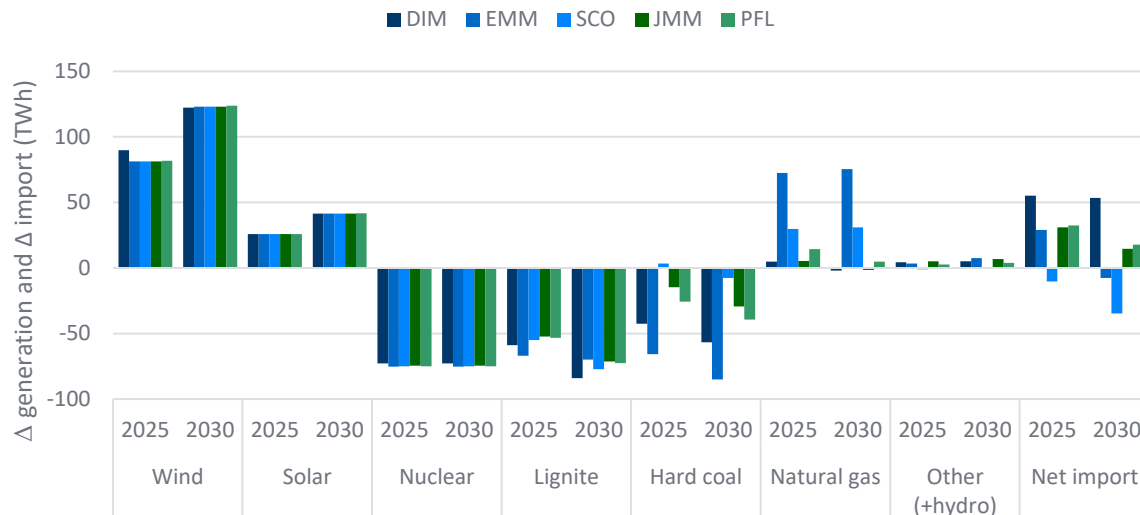


Figure 8: Inner difference of annual electricity generation and net import (reference scenario years 2025 and 2030)

Most models yield a comparable decrease in nuclear and lignite-fired electricity generation. In contrast, considerable deviations in hard coal production occur. EMM and, to a lesser extent, DIM show comparatively large reductions in hard coal in both years, and they also show somewhat higher reductions in lignite-fired electricity generation. These reductions are compensated by gas production (EMM) and imports (DIM) and can be traced back to the endogenous decommissioning<sup>9</sup> of hard coal units and the endogenous investment<sup>10</sup> in gas-power plants for EMM and DIM (cf. Figure 9). SCO is not reducing hard coal, as the hard coal-fired production is already low in the scenario year 2016. The total hard coal-fired electricity generation (90 TWh in 2025 and 79 TWh in 2030) is actually in the range of that of other models (49-104 TWh in 2025 and 39-87 TWh in 2030). The somewhat larger decrease in the hard coal generation of PFL compared to JMM is compensated by additional natural gas-fired generation and imports.

<sup>9</sup> Recall that endogenous decommissioning is only allowed in EMM and DIM and not in SCO

<sup>10</sup> Endogenous investment in EMM and SCO exceeds TYNDP already in the reference scenario

## Endogenous investment and decommissioning

For EMM and SCO, the increase in the natural gas generation is in line with endogenous investments in gas-fired generators (Figure 9).

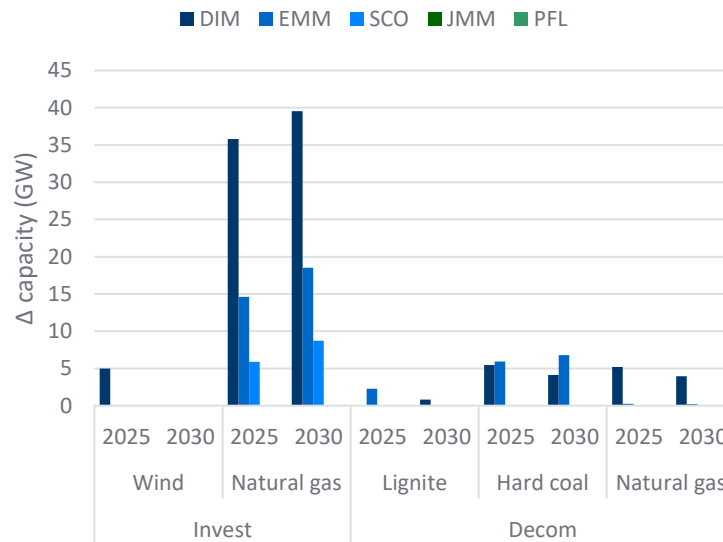


Figure 9: Endogenous change in capacity (reference scenario years 2025 and 2030)

The need for CHP replacement due to age-related decommissioning drives the gas-fired electricity generation in SCO. Interestingly, the already high gas-fired generation of DIM in 2016 is not further increased despite large investments in gas-fired power plants in 2025 and 2030. In DIM, sufficient generation capacity is enforced via a capacity constraint. This constraint requires the model to hold sufficient generation capacity to supply the peak demand, given technology-specific capacity credits which reflect their probabilistic availabilities. As coal and nuclear capacities are decommissioned in Germany in 2025 and 2030, the amount of secured capacity declines, and natural gas capacities are built endogenously to compensate for this reduction. Part of these natural gas power plants is made of open-cycle gas turbines which serve as back-up power plants for peak load and contribute only to a small extent to the total electricity generation.

Moreover, JMM and PFL show only small additional gas generation as a response to exogenous decommissioning of coal-fired and nuclear power plants. As these models do not

include endogenous investments, this additional gas-fired electricity generation results from higher utilisation rates.

### Base price, CO<sub>2</sub>-emissions and costs

Figure 10 depicts the reference scenario's inner differences of the economic and ecologic parameters.

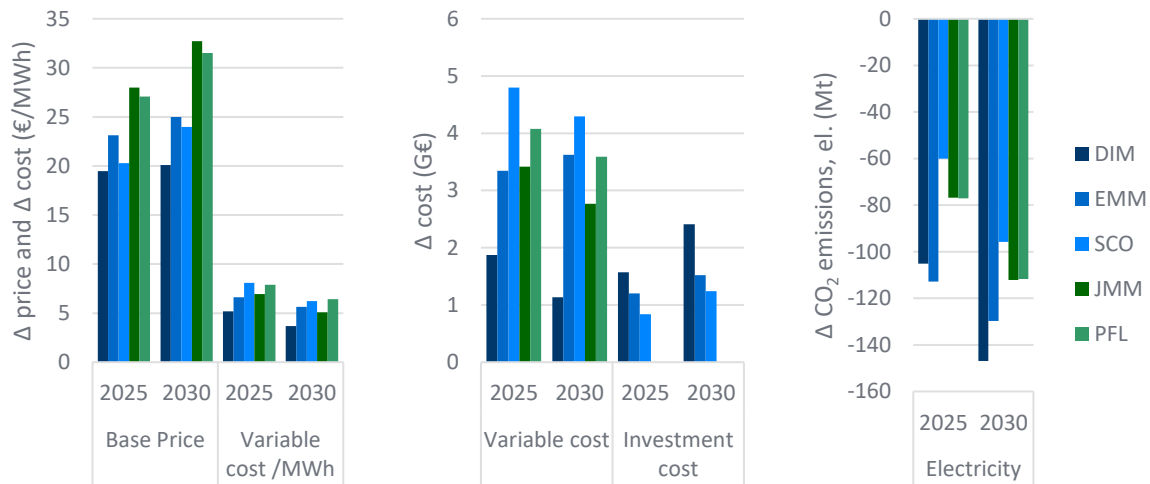


Figure 10: Inner differences of economic and ecological indicators (reference scenario years 2025 and 2030)

The base price reveals the distinct characteristics of the dispatch models (JMM, PFL) vis-a-vis the investment models: as dispatch models lack the possibility of endogenous capacity expansion. Electricity becomes scarce in times of high residual load, leading to scarcity prices of 500 €/MWh<sup>11</sup>. In contrast, the investment models invest endogenously so that either the capacity is always sufficient (DIM, SCO) or so that the frequency of scarcity prices remains under a given threshold (EMM).

The model results for the average variable cost are homogenous: by 2025, they increase by 5-8 €/MWh and slightly decrease afterwards. The somewhat lower increase in average variable cost for DIM should be interpreted relative to the base year 2016. In that base year, the average variable cost is already highest for DIM because of the large share of gas-fuelled

<sup>11</sup> This value is implemented in the objective function of the dispatch models as a penalty term for not serving load. It is chosen to be higher than the most expensive generation technology but small enough to maintain the interpretability of resulting prices.

power generation. Furthermore, the additional endogenous wind investment in DIM lowers the average variable cost.

Interestingly, the model results for the total variable cost feature substantially larger variations. The latter can be traced back to the role that imports play in the different models: high total variable cost in SCO is due to increasing exports, while the low total variable cost in DIM results from increasing imports. These differences level out in the average cost per (domestic) production.

The inter-model investment cost ranking reflects the endogenous investment decisions: DIM has the highest investment in terms of capacity and cost, followed by EMM and SCO. The fact that the investment costs do not proportionally scale with the investment capacity is due to different discount rate assumptions and different types and costs of gas power plants that are determined endogenously (open-cycle, closed-cycle and CHP turbines).

Regarding CO<sub>2</sub>-emissions, the models can be divided into three clusters. The highest CO<sub>2</sub>-emissions reduction is achieved by DIM and EMM, which are the only models that allow for endogenous decommissioning of coal-fired power plants. While the two dispatch-only models, JMM and PFL, likewise report somewhat lower emissions reductions, the reduction is even lower in the other dispatch-and-investment model SCO. Already low emissions in the scenario-year 2016 due to low hard coal generation can explain this.

### 4.3 Coal exit scenarios (outer differences)

While the preceding Sections performed the analysis of the reference scenario, this Section turns to the core of the policy analysis: the evaluation of the impact of two different coal phase-out strategies. As introduced in Subsection 2.2, this evaluation is done in terms of outer differences. These are the inner differences of the coal exit scenarios subtracted by the inner differences of the reference scenario, for the scenario-years 2025 and 2030 respectively. To ease the comparison of the two implemented coal exit approaches, the results of both scenarios are displayed and discussed next to each other.

#### Generation and net export

The outer differences in the electricity generation are plotted next to the corresponding net export in Figure 11. For clarity, only fuel types for which the model results deviate are included. It is important to note that the outer difference assesses the coal exit scenarios relative to the reference scenario and does neither reveal the absolute quantities in the scenarios, nor the scenario development relative to the base year.



Figure 11: Outer difference of annual electricity generation and net import (coal exit scenarios 2025 and 2030)

As expected, all models reduce coal generation in both coal exit scenarios. While the magnitude of the reduction is relatively similar for lignite (except for EMM in 2025), more considerable model differences are observed for hard coal. These heterogeneous outer

differences can be traced back to discrepancies already revealed by the inner differences. For example, the small incremental reductions in DIM and EMM in the coal exit scenarios match the large reductions already seen in the reference scenario (see Figure 11). Put differently, the coal capacity reduction resulting from the coal exit depends on which reductions the models foresee without a coal exit. Note that the changes in the electricity generation are directly related to the changes in the net exports as presented in Figure 11.

Furthermore, all models yield that the reduction in coal generation is less pronounced in coalex2 as compared to coalex1. In the coalex2 scenario, the endogenous decommissioning of coal units in the investment models leads to an optimal selection of shutdowns in the context of the coal phase-out (cf. Figure 12). As a result, there is no outer difference in the hard-coal generation for EMM, and the production even increases for DIM. This is because the endogenous decommissioning in the reference scenario already partly (DIM) or even completely (EMM) meets the coalex2 scenario's endogenous decommissioning target. In the coalex1 scenario, by contrast, the exogenous decommissioning is performed on other plants than the ones decommissioned endogenously in the reference scenario, which then adds up. While in coalex1 coal CHP units are also decommissioned<sup>12</sup>, in coalex2 coal CHP units are less decommissioned, which leads to a lower need for substitution by gas-fired plants (see DIM and EMM). For EMM, this need substantially increases in 2030, as compared to 2025. JMM shows only small deviations between the scenarios and years, whereas the other dispatch-only model PFL shows larger deviations, especially for lignite and to a lesser extent for hard coal between the scenarios in 2030.

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<sup>12</sup>Note that missing CHP capacities are compensated by generation expansion in the investment models and heat boilers in the dispatch models.



Figure 12: Outer difference of endogenous change in capacity (coal exit scenarios 2025 and 2030)

Essentially, two options are available to the models for substituting coal generation in both scenarios: domestic natural gas production and imports. In detail, however, the model results differ in the relative share of these two options. Dispatch models need to rely on imports as the coal phase-out cannot fully be compensated by domestic production. In contrast, investment models with the option of capacity expansion reinforce their domestic gas-based production, especially in the coalex1 scenario. Note that DIM also increases endogenous investment in wind power to compensate for coal.

Interestingly, the model results on how to substitute coal are more homogenous in the coalex2 scenario: all models primarily rely on imports. The domestic increase in natural gas production in the coalex1 scenario is driven by the exogenous decommissioning of CHP plants that need to be substituted domestically. In the coalex2 scenario, mainly power plants without heat cogeneration are decommissioned, which does not necessarily imply domestic substitution.

## Prices and costs

Figure 13 and Figure 14 show the outer differences of the economic indicators. As for the electricity generation, the general structure of these indicators is comparable for both coal exit scenarios. The electricity prices generally increase compared to the reference scenario as more expensive technologies substitute for coal generation. As expected, this effect is more substantial for the dispatch-only models. The lower variable costs of the dispatch-only models,



particularly in 2030, are directly related to the increase in imports. The missing capacity compared to the invest models results in increased imports and reduced national generation costs. Moreover, the smaller increase in investment cost and stronger decrease in variable cost for SCO matches the change in generation and net position discussed above.

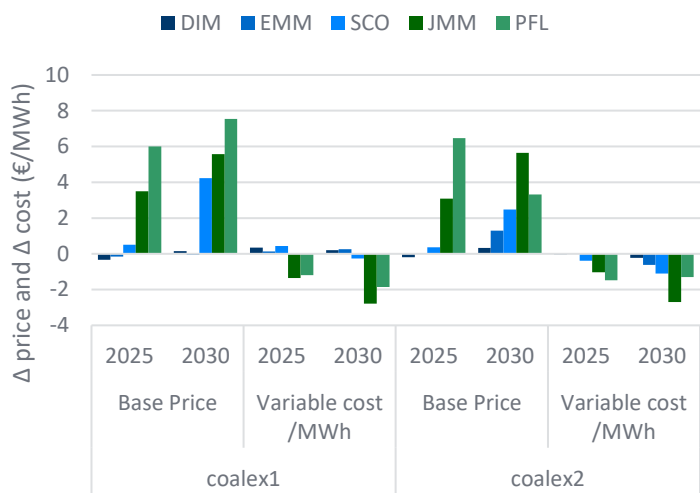


Figure 13: Outer difference of base price and average variable costs (coal exit scenarios 2025 and 2030)

For the dispatch-only models, exogenously reduced capacities in the scenario coalex1 lead to increasing generation from back-up units (slacks). This effect on market prices is lower in the coalex2 scenario where the decommissioning of coal capacities is not solely based on the age but on the profitability of generation units, thus leading to a somewhat consistent capacity reduction (e.g. with regard to CHP). In contrast, in the investment models, the capacity reductions are compensated by cost-optimal investments, thus reducing the impact on market prices.



Figure 14: Outer difference of annual variable and investment costs (coal exit scenarios 2025 and 2030)

### CO<sub>2</sub>-emissions

Again, a similar development for both scenarios is observed when comparing the annual CO<sub>2</sub>-emissions in Figure 15. In almost every model, the emissions decrease compared to the reference scenario. The most substantial reductions appear in JMM, PFL and SCO. Since these models do not allow for endogenous capacity reduction, they make up for the reduction that EMM and DIM already achieve in the reference scenario years 2025 and 2030. The differences between the two exit scenarios in terms of emission reduction can be traced back to the also different electricity generation. Since the coal capacities are only reduced in Germany in both scenarios, a shift of emissions from Germany to the surrounding countries is expected and can be observed for JMM, PFL and SCO (referred to as “waterbed<sup>13</sup>” in Figure 15). EMM and DIM only show a negligible or even reverse waterbed effect: efficient gas turbines replacing the decommissioned coal capacities do not only replace coal production in Germany but furthermore replace inefficient gas generation outside of Germany.

<sup>13</sup> Calculated as outer difference of all countries minus the outer difference of Germany.

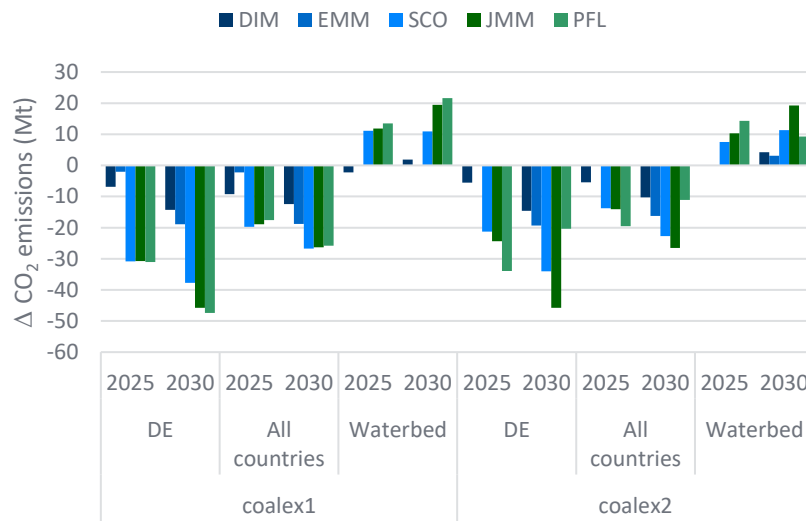


Figure 15: Outer difference of annual CO<sub>2</sub>-emissions (coal exit scenario 2025 and 2030)

## 5 Conclusion

The model comparison and proposed methodology's added-value is twofold. On the one hand, the performed model comparison allows identifying some model-related methodological takeaways. On the other hand, the considered case study allows drawing some conclusions for the coal phase-out design. In this Section, we discuss the main findings with a focus on the three dimensions reliability, efficiency and environmental compatibility of the power supply.

This contribution expands on that of earlier studies and provides some more general takeaways for both modellers and decision-makers. Even when assumptions, i.e. input data are harmonised, some residual uncertainty remains due to the model formulation itself. While there is a consensus on how to model the merit-order based dispatch in electricity markets, this is less the case for technical details such as constraints for CHP, reserve provision, or ramping constraints.

Moreover, this paper proposes an evolved diff-in-diff approach to evaluate the effect of a policy instrument relative to a reference scenario. In this context, the performed analysis highlights the pivotal role of the reference scenario for the derived conclusions. In other words, the estimated effect one model yields for a coal phase-out strategy strongly depends on the endogenous and exogenous decommissioning of coal-fired power plants already included in the reference scenario of that model.

In the following, we discuss implications that can be drawn from the model comparison in three dimensions (economic, environmental and security of supply).

### **Economic implications**

Although spot prices impact retail prices (besides grid fees, levies and taxes) only to a certain extent, these are usually a focus of attention. Due to their socio-economic relevance, price effects are an essential result for decision-makers.

On the one hand, endogenous investments under perfect foresight lead to a price underestimation. On the other hand, dispatch-only models cannot optimise investments, thus

leading to a price overestimation. Therefore, the reality might lie somewhere between the two approaches.

As intensively discussed in the context of the coal exit negotiations in Germany, the influence of prices on compensation payments for plants to be decommissioned illustrates their importance for phase-out decisions. We observe differing effects on system costs between the considered modelling approaches. Due to missing investments, dispatch-only models tend to overestimate cost effects and hence opportunity costs (= compensation payments) of the plants to be decommissioned. Lost revenues moreover impact opportunity costs on other markets for heat and control reserve. Consequently, the exclusion or simplification of relevant market segments might result in different results and conclusions.

### **Environmental implication**

The wide range of resulting CO<sub>2</sub> emissions between the models underpins the difficulty to reach a given emission reduction target when using capacity reductions as a policy instrument. While under the naive coalex1 scenario, mainly old and more CO<sub>2</sub>-intensive generation units are closed, this is not the case under coalex2 where a cost minimal capacity reduction is realised. Thus, despite identical capacity reductions, national CO<sub>2</sub> reductions are higher under coalex1. Moreover, in the context of interdependencies with the European energy system, the dispatch-only models tend to overestimate the waterbed effect, as these models can not invest in renewables and efficient natural gas-fired power plants compensating for the decommissioning of coal plants. For coal capacity reductions to be most effective in terms of reaching a specified emission reduction target, they must be complemented with additional investment in generators with lower carbon intensity. While volume-based mechanisms (e.g. emission caps) enable a direct control of the emission reduction, a regular monitoring could reduce uncertainty under capacity-based mechanisms.

## **Security of supply**

Besides the economic and environmental dimensions, the security of supply is an essential aspect in the field of energy system modelling. While not in the focus of this model experiment, some indicators allow drawing some conclusions here.

First, the impact on the scarcity of generation capacity can be measured by the scarcity prices. In this regard, the results of the dispatch-only models are heavily driven by the exogenous capacities which might lead to a divergent view on scarcity under the coal phase-out scenarios.

Second, the dependency on imports can provide information about the security of supply. The model experiment revealed that most models foresee Germany to become a net importer under the coal exit by 2030. When it is not the case (DIM in 2025), generation investments into renewables, i.e. wind generation capacities, can be identified as a primary driver.

Finally, it should be noted that the instruments' cross-sectoral interdependencies might lead to adverse effects and issues for security of supply, e.g. in the heat sector. This is illustrated by the naive coalex1 scenario results, where the decommissioning of coal units according to their age leads to considerable capacity gaps in local heat networks (that are addressed by generation expansion in the investment models and heat boilers in the dispatch models).

## **Outlook**

While this model comparison focused on the implications of administrative, national coal phase-out plans, further model experiments are foreseen. One model comparison will analyse the role of CO<sub>2</sub> pricing in a national and European context. Further research will moreover extend to one of the main drivers of model differences – the modelling of CHP.



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## **Data availability**

Relevant input data with regards to time series and capacities is available upon request.





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## Appendix A: Model overview

Table 1: Overview of utilised models

Institution	Model	Abbreviation
University Duisburg-Essen, Chair for Management Science and Energy Economics	Joint Market Model	JMM
Institute of Energy Economics at the University of Cologne (EWI)	DIMENSION+	DIM
Fraunhofer Institute for Energy Economics and Energy System Technology IEE	SCOPE - Electricity Market	SCO_dis
	SCOPE - Scenario Development	SCO_inv
Hertie School of Governance	EMMA	EMM
Öko-Institut e.V.	Powerflex	PFL

The following tables compare main characteristics of the models as utilized in this model experiment. In general, further model configurations might be implemented, but are not considered here.

Table 2: Model-specific Characteristics

	<i>DIM</i>	<i>EMM</i>	<i>SCO_inv</i>	<i>SCO_dis</i>	<i>JMM</i>	<i>PFL</i>
<b>Programming Technique</b>						
Linear	yes	yes	yes	no	yes	yes
Mixed-Integer	no	no	no	yes	no	no
<b>Simulation Approach</b>						
Integrated Optimization	yes	yes	yes	no	no	yes
Rolling Planning Horizon	no	no	no	yes	yes	no
Sequential or Parallel Computing	no	no	no	no	no	no
<b>Endogenous Features</b>						
Generation Capacity Investment						
Electricity	yes	yes	yes	no	no	no
Heat	yes	yes	yes	no	no	no
Storage Capacity Investment	yes	yes	yes	no	no	no
Transmission Capacity Investment	no	no	no	no	no	no
Generation Dispatch						
Electricity	yes	yes	yes	yes	yes	yes
Heat	yes	yes	yes	yes	yes	yes
Storage Dispatch	yes	yes	yes	yes	yes	yes
Load Flows	no	no	no	no	no	no
Trade Flows	yes	yes	yes	yes	yes	yes
Technological Learning	no	no	no	no	no	no

Market Prices	yes	yes	yes	yes	yes	yes
Emission Rates and Prices	yes	yes	yes	yes	yes	yes

Table 3: Market representation

	<i><b>DIM</b></i>	<i><b>EMM</b></i>	<i><b>SCO_inv</b></i>	<i><b>SCO_dis</b></i>	<i><b>JMM</b></i>	<i><b>PFL</b></i>
<i><b>Energy Sectoral Coverage</b></i>						
Electricity	yes	yes	yes	yes	yes	yes
Heat	yes	yes	yes	yes	yes	Only DE
Transportation, Mobility	no	no	no	no	no	no
Industry	no	no	no	no	no	no
<i><b>Represented Markets</b></i>						
Spot Market	DA	DA	DA	DA	DA	DA
Balancing Reserve Market						
Primary	symmetric	pos, neg	no	no	pos, neg	pos
Secondary	pos, neg	pos, neg	no	pos, neg	pos, neg	pos
Tertiary	pos, neg	no	no	pos, neg	pos, neg	pos
Balancing Energy Market	no	no	no	no	no	no
Capacity Market	no	no	no	no	no	no
<i><b>Policy Constraints</b></i>						
CO2 Emissions Constraints	yes	no	yes	no	no	yes
Technology Restrictions	yes	yes	yes	yes	yes	yes
RES Quota	yes	yes	no	no	no	no
RES Subsidy	yes	no	no	no	no	no
CO2 Trading	yes	no	yes	no	no	no

Table 4: Detail of modelling

	<i><b>DIM</b></i>	<i><b>EMM</b></i>	<i><b>SCO_inv</b></i>	<i><b>SCO_dis</b></i>	<i><b>JMM</b></i>	<i><b>PFL</b></i>
<i><b>Spatial Coverage</b></i>	EU28 w/o MT & CY w CH & NO	AT, BE, CH, CZ, DE, DK, FR, GB, NL, NO, PL, SE	EU28 w/o MT & CY w CH & NO	EU28 w/o MT & CY w CH & NO	EU28 w/o MT & CY w CH & NO & Balkans	EU28 w/o MT & CY w CH & NO
<i><b>Spatial Resolution</b></i>						
Electricity	zonal	zonal	zonal	zonal	zonal	zonal
Heat Networks	none	vintage- wise	Unit-wise	Unit-wise	heat regions	heat regions
<i><b>Representation of Time</b></i>						
Integrated Optimization	yes	no	no	no	no	no
Time Aggregation	yes	no	no	no	no	no
<i><b>Costs Included</b></i>						
Investment Costs	yes	yes	yes	no	no	no
Fixed O&M Costs	yes	yes	yes	no	yes	no
Fuel Costs	yes	yes	yes	yes	yes	yes

Other Variable Costs	yes	yes	yes	yes	yes	yes
Carbon Tax	yes	yes	yes	yes	yes	yes
<i>Details of Thermal Generation</i>						
Partial Efficiencies	yes	no	no	yes	yes	no
Start-up Costs	yes	no	no	yes	yes	no
Ramping constraints	yes	no	yes	yes	yes	yes
Min. downtimes	no	no	no	yes	yes	no
Min. operating times	no	no	no	yes	yes	no
Time-Dependent Availabilities	yes	yes	yes	yes	yes	yes
<i>Details of Storage Modeling</i>						
Charging and Discharging Capacity	yes	yes	yes	yes	yes	yes
Storage Capacity	yes	yes	yes	yes	yes	yes
Additional Inflow	yes	no	yes	yes	yes	yes
Storage Losses	yes	yes	yes	yes	yes	yes
Resolution of Reservoir Modeling	aggr. by country	aggr. by country	detailed	detailed	aggr. by country	aggr. by country
<i>Hydro-Thermal Generation Technologies</i>						
Installed Capacity	yes	yes	yes	yes	yes	yes
Differentiation of Vintage Classes	no	yes	yes	no	yes	yes
Unit-wise	no	no	no	yes	no	Only DE
<i>Simplifications for Europe outside Germany</i>						
(Stronger) Aggregation of Generation Units	no	no	yes	yes	no	yes
Aggregation of Hydro Reservoirs	no	no	yes	no	no	yes
Aggregation of Heat Networks	no	no	no	no	no	n.a.
Aggregation of Market Zones	no	no	no	no	no	yes
Exogenous Import/Export	no	yes	no	no	no	no
Consideration of Co-Generation/ Heat Demand	no	yes	yes	yes	no	no

## Appendix B: Yearly aggregated indicators

Reliable indicators need to be defined for which the differences in results (model outcome) are measured. Table 5 provides an overview over yearly and country wise aggregated indicators that are used to analyse the model results in Section 4.

Table 5: Overview of yearly aggregated indicators

Indicator	Unit	Description
<b>ECONOMICAL</b>		
<b>invcost</b>	Euro	sum of investment costs for newly build plants (only valid for models with endogenous capacity expansion)
<b>prodcost</b>	Euro	sum of costs for generation (based on fuel usage)
<b>varcost</b>	Euro	sum of costs including costs for generation, start-ups, transmission and model specific penalties
<b>variable cost per MWh</b>	Euro/MWh	division of the parameters varcost and generation
<b>price</b>	Euro/MWh	averaged (unweighted) wholesale electricity prices
<b>TECHNICAL</b>		
<b>capacity</b>	GW	installed capacities per fuel and country
<b>generation</b>	TWh	sum of generation per fuel type and country
<b>netposition</b>	TWh	difference of summed electricity exports and imports
<b>ENVIRONMENTAL</b>		
<b>co2</b>	Mio. tCO <sub>2</sub>	sum of CO <sub>2</sub> -emissions
<b>co2el</b>	Mio. tCO <sub>2</sub>	sum of electricity-based CO <sub>2</sub> -emissions
<b>co2th<sup>14</sup></b>	Mio. tCO <sub>2</sub>	sum of heat-based CO <sub>2</sub> -emissions

<sup>14</sup> Only emissions for heat generation that can be isolated from electricity production are included here. That is the case for e.g. heatboilers and heat from extraction units. Emissions of backpressure units are fully accounted as electricity-based CO<sub>2</sub>-emissions.