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The transformation of integrated electricity and heat systems—Assessing mid-term policies using a model comparison approach

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Abstract

The development of European power markets is highly influenced by integrated electricity and heat systems. Therefore, decarbonization policies for the electricity and heat sectors, as well as numerical models that are used to guide such policies, should consider cross-sectoral interdependencies. However, although many model-based policy assessments for the highly interconnected European electricity system exist, international studies that consider interactions with the heat sector are rare. In this contribution, we systematically study the potential benefits of integrated heat and power systems by conducting a model comparison experiment. Five large-scale market models covering electricity and heat supply were utilized to study the interactions between a rather simple coal replacement scenario and a more ambitious policy that supports decarbonization through power-to-heat. With a focus on flexibility provision, emissions reduction, and economic efficiency, although the models agree on the qualitative effects, there are considerable quantitative differences. For example, the estimated reductions in overall CO₂ emissions range between 0.2 and 9.0 MtCO₂/a for a coal replacement scenario and between 0.2 and 25.0 MtCO₂/a for a power-to-heat scenario. Model differences can be attributed mainly to the level of detail of CHP modeling and the endogeneity of generation investments. Based on a detailed comparison of the modeling results, implications for modeling choices and political decisions are discussed.

Highlights

- We assess benefits of combined heat and power in a model comparison experiment
- In a case study, we analyze a coal phase-out scenario and a power-to-heat scenario
- We focus on flexibility provision, emissions reduction, and economic efficiency
- Differences are driven by granularity of CHP modeling and endogeneity of investment

Keywords

Combined heat and power, power-to-heat, coal phase-out, renewable energy, energy system transformation, electricity market modeling, model comparison

The authors are solely responsible for the contents, which do not necessarily represent the opinions of their institutions.

Abbreviations

26C	26 European countries included in the study scope
β	Power loss ratio
bp	Backpressure
CHP	Combined heat and power
co	Condensing
COP	Coefficient of performance
cr	coal replacement scenario
DIM	DIMENSION model
ec	Extraction-condensing
EMM	EMMA electricity market model
i, I	Set of all facilities (i.e., CHP plants, heat boilers, heat pumps, and heat storages)
JMM	Joint market model
P	Power
PFL	PowerFlex model
PtH	Power-to-heat (scenario)
Q	Heat
r, R	Set of regions (e.g., country, fuel-specific balance area, or heat network)
ref	reference scenario
RES	Renewable energy sources
σ	Power-to-heat ratio
SCO	SCOPE model
t, T	Time steps

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1 Introduction

To achieve a reduction in CO₂ emissions, energy policy measures have focused on supporting renewable energy sources (RES) in Europe over the past two decades. The massive expansion of wind and solar energy has primarily led to the decarbonization of the electricity sector. In contrast, other sectors, such as centralized heating, have barely reduced CO₂ emissions, calling for additional policy measures and strategies [1]. To increase the overall efficiency of conventional power plants, existing policies have focused on the cogeneration of heat and power, which has therefore become an important element of the European energy system [2]. The political goal of enhancing the use of combined heat and power (CHP) while also fostering the use of power-to-heat (PtH) underpins the growing importance of linking the electricity and heat sectors [3].¹ While alternative fuels and technologies, such as renewable hydrogen, biomethane, and solar thermal energy, will be needed to decarbonize the heat sector in the long term, strategies based on retrofitting existing CHP plants² and complementing these with PtH may be a promising mid-term solution [5]–[9].

In order to study the role of CHP and PtH in the decarbonization of centralized heat and power sectors, adequate models linking both sectors are needed. Existing studies take different approaches to modeling integrated electricity and heat systems and differ with regard to their perspective and focus. To account for the technical details, most models are formulated as mixed-integer linear programming problems. Examples include studies considering single CHP units or local small-scale systems (e.g., [10]–[12]). Further contributions extend the perspective to national heat and power systems (e.g., [13], [14]) and include investment decisions (e.g., [15]–[17]). While many studies exist on the highly interconnected European electricity system (e.g., [18]–[21]), international studies considering interactions with the heat sector are rare. Moreover, models that do consider the heat sector are usually based on simplifications (see also [22]). With the exception of a recent study on the role of PtH in the decarbonization of the Northern-central European energy system [8], large-scale and European applications remain an exception (see [23], [24]). This contribution aims to fill this gap.

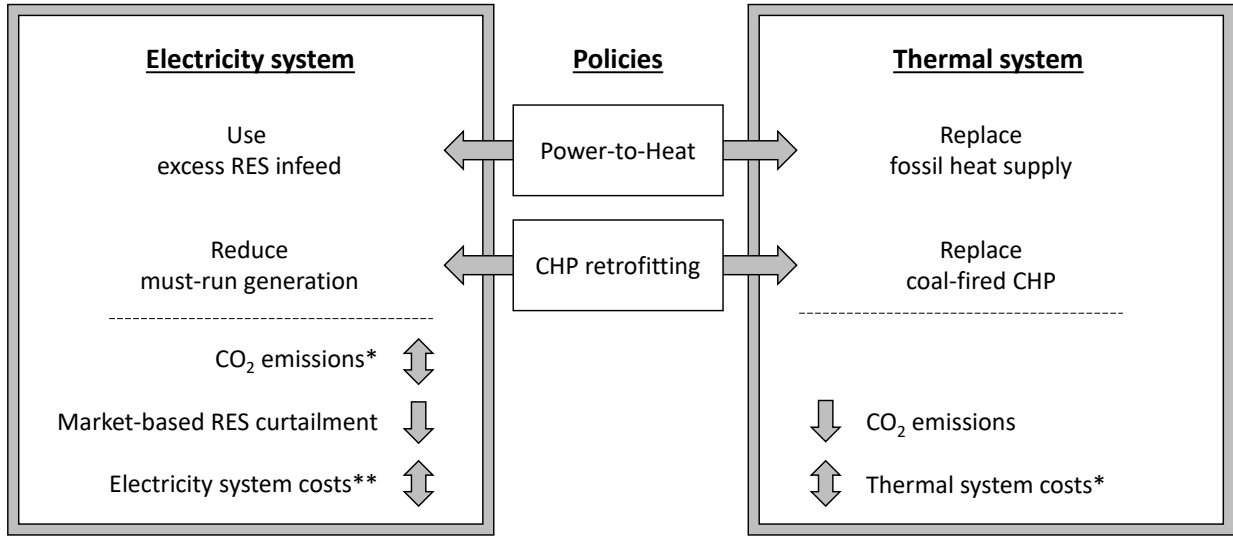
Several studies have addressed the potential benefits of combining heat and power (e.g., [15], [25]–[27]). Accordingly, the main motivation is the more efficient use of fuel, which enables cost savings and a reduction in emissions. Moreover, PtH in particular is seen as a potential source of flexibility to help integrate variable RES [12]. In this context, Beiron et al. [28]

¹ The European Energy Efficiency Directive is under revision to account for the updated European climate targets under the European Green Deal [4].

² In this contribution, retrofitting refers to the replacement of CO₂-intense CHP technologies, such as coal and lignite, with less CO₂-intense CHP technologies, such as natural gas. This may be considered as a mid-term strategy that allows a straightforward replacement of natural gas with renewable synthetic fuels for a deep decarbonization in the long term.

provided a general framework for analyzing the flexibility of CHP systems. The authors proposed a differentiation of flexibility between the plant level and the system level. While the plant level addresses operational flexibility (i.e., load ranges, ramp rates, and cycling properties) and product flexibility (i.e., adapting the ratio between heat and electricity), the system level covers thermal flexibility and electricity system flexibility (i.e., load shifting and coping with the variability of demand and RES). As the technical parameters of power plants are considered exogenous factors, in this contribution, we focus on flexibility at the system level. Furthermore, we are interested in the impacts of mid-term policies, such as CHP retrofit and complementing PtH, on overall system costs and CO₂ emissions.

Replacing CO₂-intense CHP technologies, such as coal and lignite, with modern gas-fired CHP units can be expected to improve thermal flexibility and reduce must-run generation through higher operational and product flexibility (see Figure 1). The impact of retrofitting and replacing coal with gas on operational costs depends on the level of fuel and CO₂ prices. Nevertheless, the higher efficiency of modern CHP units is expected to reduce fuel consumption. With regard to decarbonization, the replacement of coal-fired CHP units with gas-fired units, as well as the higher efficiency of modern CHP units, will result in a lower CO₂ intensity of electricity and heat supply. Moreover, an indirect reduction in emissions can be expected because of the lower must-run generation of CHP. PtH can replace fossil heat supply and support the electricity system in situations with excess RES infeed, helping to cope with the residual electrical load. Consequently, PtH can help integrate variable RES and hence reduce CO₂ emissions of the heat supply. Moreover, the additional flexible consumption of PtH can be expected to drive up the market value of RES, leading to higher market-based investments in these CO₂-neutral technologies [29]. Finally, it should be noted that the benefits of combined heat and power systems depend on the regulatory framework. While Møller Sneum et al. [30] stated that existing taxes and subsidies have been found to have limited impact on the operation of CHP plants and electric boilers in the Baltic countries, levies create barriers for PtH in Germany (see [31], [32]).



* Depending on RES investments ** Depending on fuel and CO₂ prices (fuel switch)

Figure 1: General impacts of the considered mid-term policies on integrated heat and power systems

We systematically studied these potential benefits by conducting a model comparison experiment. Five large-scale market models covering electricity and heat supply were utilized to examine the interactions between a rather simple coal phase-out scenario and more ambitious policies supporting the decarbonization of integrated electricity and heat systems by electrification. All models consider the European perspective with a high degree of technical detail regarding the cogeneration of heat (see Section 2). Mid-term policies for the decarbonization of integrated heat and power systems, such as retrofitting CHP and complementing this with PtH, are evaluated using the example of Germany. There are several model comparison projects with a focus on the electricity sector (e.g., [33]–[37]). Building on previous work, this study is the first to compare electricity market models in the context of the decarbonization of integrated electricity and heat systems.

The remainder of this paper is structured as follows. In Section 2, we introduce the experimental framework, including an overview of the modeling approach and the considered scenarios and indicators that are compared between the five electricity market models. Section 3 presents the results of the model comparison experiment and analyzes the model differences with a focus on the provision of flexibility, system costs, and CO₂ emissions. Section 4 discusses the main implications of the obtained model differences and concludes this paper.

2 Experimental setup

2.1 Models and scope

The model comparison includes five models with a focus on the European power markets while also considering the provision of heat for district heating. The five models are the PowerFlex

model (PFL) [38], the Joint market model (JMM) [39], the SCOPE model³ (SCO) [40], the EMMA electricity market model (EMM) [41], and the DIMENSION model (DIM) [42]. All of these models are well established and have been used for research or consulting purposes (e.g., [29], [43]–[56]). Each model depicts the key features of electricity markets with hourly resolution (i.e., dispatch of power plants, infeed of renewables, storage modeling, and electricity exchanges between countries). The SCO, EMM, and DIM also calculate investment decisions for an optimal composition of the European power plant mix. Beyond that, the EMM and DIM model the decommissioning of power plants endogenously. Moreover, the models differ in techno-economic details (e.g., efficiency losses at part load or cogeneration of heat, vintage-wise or unit-wise power plant modeling, etc.) and geographical coverage. For a detailed discussion of (general) model differences, see [57], [58].

The models differ in geographical coverage concerning the overall number of countries depicted and the number and granularity of the modeled district heating systems. In terms of the European electricity system, EMM considers 12 northwestern European countries, while the other models include between 26 and 29 countries. Regarding the geographical scope of thermal systems, the differences are more pronounced. While all five models consider the integrated electricity and heat system in Germany, the JMM, SCO, and EMM additionally consider the heat demand of the remaining European countries. Concerning the granularity of heating systems, two models include a detailed representation of local heat networks (JMM and SCO), while the others aggregate heat demand at a higher level (PFL, EMM, and DIM⁴).

2.2 Modeling integrated electricity and heat systems

While there is consensus on the modeling of most features of the electricity market, the depiction of district heating systems reveals larger differences. In the following paragraphs, we assess these differences and similarities in more detail by taking a closer look at model formulations. In order to determine the similarities, we reduce the respective equations to common elements that can be found in all, or a majority of, the models. The main differences are then discussed in the subsequent explanations.

Four of the models include a heat balance equation (the DIM, JMM, PFL, and SCO), while the EMM does not explicitly model a heat balance but applies heat-related constraints directly to the electricity generation variables:

³ The SCOPE model family encompasses different models. For this model experiment, we used the deterministic linear investment model SCOPE SD in combination with the dispatch model SCOPE EM. The endogenously determined capacities from SCOPE SD were transferred to SCOPE EM. SCOPE EM is a mixed-integer model with a higher amount of technical details (e.g., minimum up times, part-load limit) and in contrast to SCOPE SD, considers balancing reserve provision.

⁴ Note that the DIM further distinguishes industrial and residential heat demand.

$$\sum_i PRODUCTION_{t,i,r}^{HEAT} = demand_{t,r}^{HEAT} \quad (1)$$

$$\forall t \in T, i \in I, r \in R$$

In equation (1), T represents the set of all time steps, I is the set of all facilities (i.e., CHP plants, heat boilers, heat pumps, and heat storages) that can provide heat, and the set R defines the (spatial) scope of the energy balance (e.g., country, fuel-specific balance area, or heat network). While the basic form of this equation can be found in most of the considered models, they disagree on the time representation, the detail of the unit representation, and the regional scope. In DIM, T represents not only all hours of one year but also all modeled years, as it is the only investment model that implements an intertemporal optimization approach. The set of all systems I represents either vintage-wise aggregated generation units (JMM, DIM) or single plants (PFL, SCO). Furthermore, R stands for either the set of fuel-specific energy balances (PFL), the heat demand cases—industry or residential (DIM), the set of all regional heat networks (JMM), or all local heat supply systems⁵ (SCO). The JMM thereby differentiates between two types of heat networks: (i) detailed grids with a unit commitment based on the variable costs of heat supply and (ii) aggregated heat networks with a pro-rata heat output to depict must-run generation in small heat networks and small independent heat-driven units. All the models that use a heat balance equation include the consumption of heat storages in that equation, while the JMM and SCO factor in heat losses as well. For the sake of comparability, neither heat storages nor heat losses are considered in this model experiment and are therefore neglected in equation (1).

In addition, four models (DIM, JMM, PFL, and SCO) include a capacity restriction that limits the maximum heat generation of single heat suppliers to thermal capacity, as seen in equation (2). A corresponding minimum heat restriction was not considered in the models.

$$PRODUCTION_{t,i,r}^{HEAT} \leq capacity_{i,r}^{HEAT} \cdot availability_{t,i,r} \quad (2)$$

$$\forall t \in T, i \in I, r \in R$$

While the DIM, JMM, and SCO reduce the thermal capacity by an availability factor, the PFL neglects this parameter, implicitly assuming 100% availability of CHP units. Two of the models (DIM and SCO) allow for an endogenous addition of CHP capacity so that $capacity_{i,r}^{HEAT}$ is represented as a decision variable in contrast to the parameter formulation in dispatch-only models (JMM and PFL).⁶ Moreover, in one model (SCO), the constraint includes a binary status

⁵ In the SCO, each heat supply system consists of a CHP plant and a heat boiler (plus PtH or a heat storage depending on the scenario).

⁶ Note that the EMM also allows endogenous investment but does not include the heat capacity constraint.

variable, as it is implemented as a mixed-integer problem. Within the JMM, the capacity constraints are differentiated for regions with aggregated heat demand (some European countries) and others with more detailed calculations of the heat balance (for DE and most neighboring countries).⁷ All five models include a comparable capacity restriction limiting the maximum electricity generation, while two of the models (JMM and SCO) also consider a minimum power restriction.

All five models incorporate CHP generation units with *extraction-condensing turbines* and *backpressure turbines*. Figure 2 shows a simplified representation of the relevant restrictions for both technologies. *Extraction-condensing turbines* allow for the adaption of simultaneous heat (Q) and power (P) production subject to technical limitations, which are represented by the polyhedron in Figure 2a. Figure 2b shows the operational limits of *backpressure turbines* with a fixed ratio of heat and power generation, defined by the power-to-heat ratio. For both technologies, the maximum heat production (Q_{\max}) is limited by constraint in equation (2), as introduced in the previous paragraph (see also the vertical lines in Figure 2a and Figure 2b).

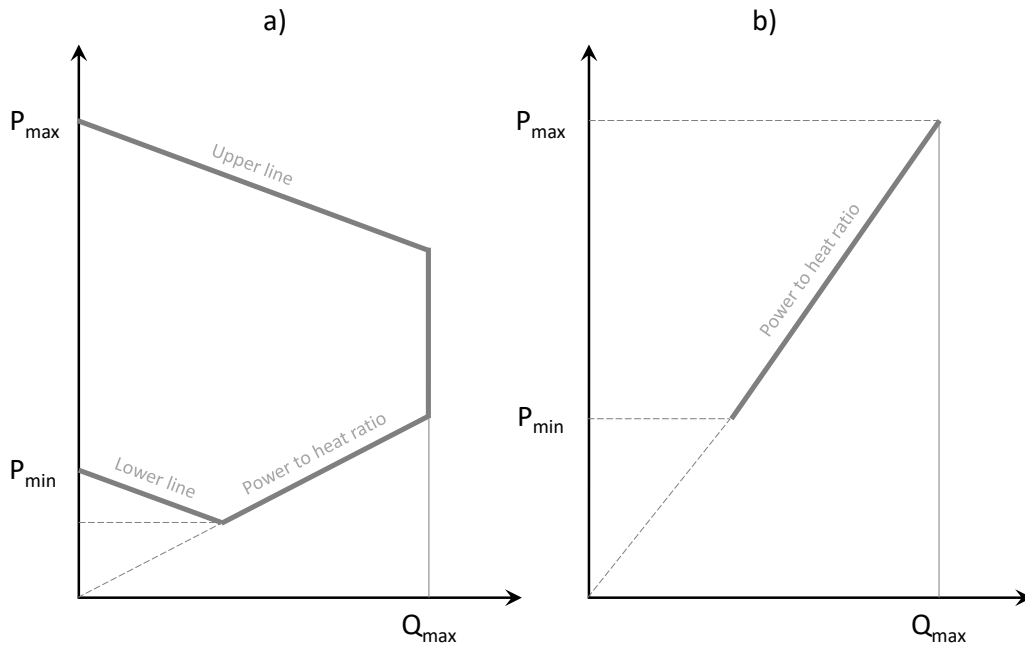


Figure 2: Simplified PQ chart for a) extraction-condensing turbines and b) backpressure turbines

According to Figure 2a, the modeling of *extraction-condensing turbines* requires the implementation of three further restrictions. The line according to the power-to-heat ratio is represented by the following constraint:

$$PRODUCTION_{i,t}^{POWER} \geq PRODUCTION_{i,t}^{HEAT} \cdot \sigma_i \quad (3)$$

⁷ To reduce the computational burden, the heat supply and resulting limitations for the power output of CHP units located in DE and most neighbouring countries was determined using a CHP module that is coupled with the JMM (for details, see [23]).

$$\forall t \in T, i \in I^{ec}$$

The upper line of the PQ chart restricts the maximum electricity production (P_{\max}) of CHP units, which decreases with increased heat extraction, as in equation (4).

$$\begin{aligned} PRODUCTION_{i,t}^{POWER} & \leq availability_{i,t} \cdot capacity_{i,t}^{POWER} - PRODUCTION_{i,t}^{HEAT} \cdot \beta_i \\ & \forall t \in T, i \in I^{ec} \end{aligned} \quad (4)$$

Moreover, the lower line of the PQ chart defines the minimum electricity production (P_{\min}) as determined by equation (5).

$$\begin{aligned} PRODUCTION_{i,t}^{POWER} & \geq availability_{i,t} \cdot mincapacityfactor_i^{POWER} \cdot capacity_i^{POWER} \\ & - PRODUCTION_{i,t}^{HEAT} * \beta_i \\ & \forall t \in T, i \in I^{ec}, \end{aligned} \quad (5)$$

where I^{ec} denotes the subset of I representing all *extraction-condensing turbines*, σ_i the power-to-heat ratio, β_i the power loss factor, and $mincapacityfactor_i^{POWER}$ the minimum power generation factor. Although the basic implementation of the above restrictions is considered in four models (DIM, JMM, PFL, and SCO), the DIM and PFL neglect equation (5). Moreover, the JMM and SCO include the provision of control reserve power, and the SCO replaces the availability factor with a binary status variable. As the supply of heat demand in equation (5) while a binary status variable is added in equation (4) not explicitly modeled in the EMM, the restrictions (mentioned before) are used to derive constraints for the electricity production of *extraction-condensing turbines* (see [41] for details).

Due to the lower degree of freedom with regard to dispatching *backpressure turbines*, the implementation becomes simpler. In general, the output is determined by the (fixed) power-to-heat ratio, which corresponds to the slope in Figure 2b and is calculated according to equation (6). Consequently, *backpressure turbines* are less flexible than *extraction-condensing turbines*.

$$\begin{aligned} PRODUCTION_{i,t}^{POWER} & = PRODUCTION_{i,t}^{HEAT} \cdot \sigma_i \\ & t \in T, i \in I^{bp}, r \in R, \end{aligned} \quad (6)$$

where I^{bp} is the subset of I representing all backpressure units. The constraint is implemented in the DIM, JMM, SCO, and PFL. In the EMM, backpressure turbines are constrained such that they produce an amount of energy proportional to the residual heat demand after accounting for peak shaving by heat boilers (see [41] for details).

The investment models consider further constraints, ensuring that the installed thermal capacity is sufficiently high to cover the peak heat demand. The DIM includes a peak constraint that ensures sufficient capacity via technology-specific capacity credits, which represent probabilistic availabilities in times of peak heat demand. In the EMM, the overall installed thermal capacity of CHP units is not allowed to decrease. In the SCO, new CHP systems can be built to replace retired CHP units (and to compensate for changes in demand).

Aside from CHP units, all five models consider fossil heat boilers that only produce heat and usually serve as a backup technology in situations with peak demand or unavailability of CHP units. In general, the implementation does not require any additional constraints beyond equation (2) and assumes a provision of heat based on the marginal generation costs (determined by fuel price, fuel tax, and CO₂ price). Consequently, heat boilers are running if they are economically feasible. Nevertheless, certain model characteristics may affect the utilization of heat boilers. While the DIM allows for a free allocation of heat boilers to CHP plants, models with a more detailed representation of the heat demand assume an allocation of heat boilers to corresponding heat-balancing areas (PFL), regional heat networks (JMM), or local heat supply systems (SCO). Moreover, in the DIM, the thermal capacity of heat boilers is based on endogenous investment decisions, whereas in the PFL, SCO, and JMM, the capacity of heat boilers is not limited or is chosen sufficiently high. Like the heat balance, heat boilers are not modeled explicitly in the EMM. To account for the peak shaving of heat boilers, the heat demand is capped by the installed thermal generation capacity, assuming that the remaining heat demand is covered by heat boilers. This reduced heat demand profile is then used to derive the CHP constraints for electricity generation, as explained above. Within the optimization problem, the EMM contains only operation constraints applicable to the available CHP capacity, which assumes that the heat supply from unavailable CHP capacity is substituted by heat from heat boilers.

In general, the provision of heat by heat pumps and electrode boilers can be modeled as a linear relationship between electricity consumption and heat output. Using a constant electricity-to-heat conversion rate, PtH facilities are utilized when the electricity price divided by this efficiency rate is smaller than or equal to the variable costs of the marginal heat producer. The electricity consumption of PtH is added to the balance equation of electricity demand and is restricted by the available electrical PtH capacity. The heat output enters the heat balance, which, depending on the model, is formulated for aggregated heat-balancing areas (PFL and DIM), regional heat networks (JMM), or local heat supply systems (SCO). In the SCO, heat pumps are allocated to heat supply systems with newly built gas-fired CHP units, while electrode boilers are added to existing CHP units. Deviating from this, in the JMM, the overall capacity of heat pumps and electrode boilers is allocated to the heating networks

in accordance with the allocation of the heat demand.⁸ While the EMM does not consider the heat output of PtH, the possible heat provision from PtH implies a relaxation of the minimum electricity generation of CHP units in all models. This allows for a reduction in their must-run utilization and a more flexible operation of CHP units.

2.3 Scenarios

We present a reference scenario for the years 2016 and 2030. For 2030, two policy scenarios explore the effects of replacing coal-fired CHP plants with modern gas-fired CHP plants and of introducing electric heating capacities, such as heat pumps and electrode boilers. Data input for all models has been harmonized within the limitations defined by the different scopes and data requirements of the models. For the year 2030, we assume a CO₂ price increase to 87 EUR/tCO₂. Prices for fossil fuels are based on the “Current Policies Scenario” of the World Energy Outlook [59]. For the two dispatch models (JMM and PFL), the capacities of fossil power plants and RES are based on the scenario “Sustainable Transition 2030” in [60]. The investment models endogenously determine cost-efficient investments (DIM, SCO, and EMM) and decommissioning decisions (DIM and EMM). Further details on the data harmonization process and the underlying assumptions are presented in [57], [58]. In addition to these general data requirements, the input data required to represent heating supply and demand in Germany have been further harmonized.

The hourly heat demand profiles are based on the CHP model described in [23] and [61]. Heat demand was approximated using a piecewise linear function of ambient temperatures. Temperature profiles and annual heat demand are based on [2], [51], and [62]. The heat demand for Germany includes residential and industrial heat. For simplicity, the annual heat demand was assumed to remain constant in 2030.

The installed capacities and CHP parameters have been harmonized with a focus on Germany, as this is the common scope in all models. The dataset is based on [63] and was updated to represent the status quo in 2016. The dataset is available on request. Figure 3 shows the thermal and electrical capacities in Germany, aggregated per fuel and technology, for the reference scenario in 2016 and 2030. For the sake of comparability, the electrical output of biomass plants is fixed exogenously and not considered in the heat balance. We assumed that the total thermal capacities remain unchanged, and that decommissioned units (regardless of fuel type) are replaced by investments in modern gas-fired CHP units. Decommissioning takes the unit age and regulations regarding the German coal phase-out into account [64]. Due to

⁸ The utilization of PtH in aggregated grids (pro-rata utilization of other CHP units) depends on the average costs for heat supply in this grid. If the PtH technologies are cheaper than the average cost of heat supply, they are utilized to their maximum capacity.

the increased value of thermal flexibility in power systems with high RES shares (cf. [10], [28]), it is assumed that extraction-condensing turbine technology is used for the new CHP plants.

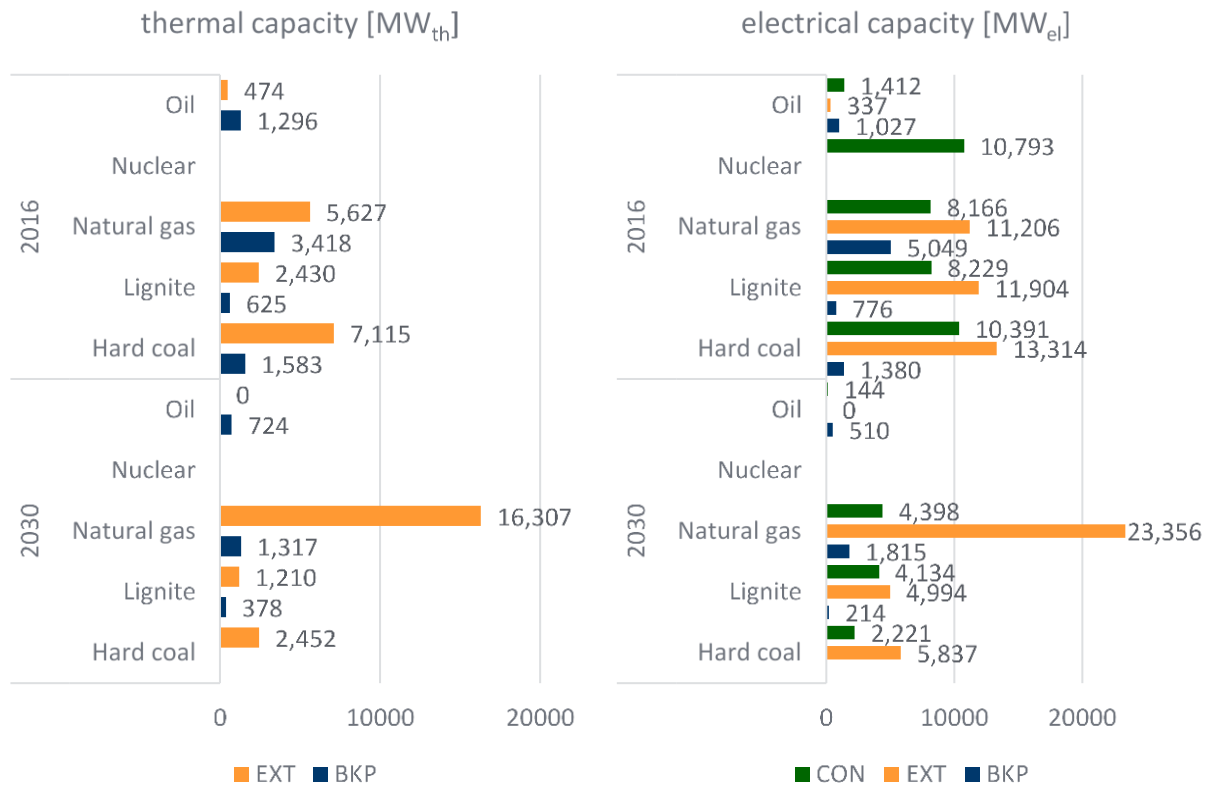


Figure 3: Thermal and electrical generation capacity of the reference scenario for Germany (EXT: extraction-condensing; BKP: backpressure; CON: condensing)

The experiment considers two policy scenarios. A coal replacement scenario investigates the impact of retrofitting existing coal-fired CHP units by replacing them with new gas-fired CHP units. It draws on the German coal phase-out and related regulations on the substitution of coal-fired generation units in the heat sector. These regulations include a state aid program for the replacement of coal-fired CHP plants with less CO₂-intense alternatives [64]. Consequently, all lignite- and coal-fired CHP units, which are not being decommissioned until 2030 in the reference scenario, are replaced by gas-fired extraction-condensing turbine CHP units of the same thermal capacity (4,040 MW_{th} in total). This corresponds to an electric capacity of 5,252 MW_{el}.⁹ The installed capacity of lignite- and coal-fired non-CHP units remains unchanged (see the capacity for condensing [CON] in Figure 3).

Electrification is a promising decarbonization option for the heating sector. While full market penetration of PtH applications is most likely to remain a long-term effort, these applications can be expected to already play a significant role in 2030. This policy scenario assumes an increase in electrode boiler and large-scale heat pump capacities until 2030 by 3 GW_{el} and

⁹ The electric capacity can be derived from the thermal capacity using a power-to-heat factor of 1.05 MW_{el}/MW_{th} and an electricity reduction of 0.25 MW_{el}/MW_{th}, as follows: 5,252 MW_{el} = 4,040 MW_{th} * (1.05 + 0.25 MW_{el}/MW_{th}).

5 GW_{el}, respectively. These values are based on the scenario framework of the German grid development plan [65]. Conventional CHP plant capacities, as well as other elements of the power system, such as renewable generation capacities, remain unchanged. We assume an efficiency of 99% for electrode boilers and a coefficient of performance (COP) of 3.33 for large-scale heat pumps [66]. Moreover, we assume a full market integration of PtH, which means that no levies apply to the electricity consumption of electrode boilers and large-scale heat pumps, which is in contrast to today's regulatory framework in Germany.

2.4 Indicators

We use various indicators to analyze the scenarios with regard to the provision of flexibility in heat and power supply, fuel mix, and CO₂ emissions and effects on system costs.

The retrofitting of CHP plants and complementing with PtH provide additional flexibility options that facilitate the matching of the supply and demand profiles in both the power and heat sectors. In the heat sector, this should reduce the *utilization of gas-fired heat boilers*, which act as a high-cost, flexible heat supply in all models. In the power sector, we use the *residual load profiles after the utilization of CHP units and PtH* as a proxy for how well retrofitted CHP plants and electrification can provide flexibility.¹⁰ CHP plants do so by reducing must-run generation in situations with excess RES infeed and by providing an additional electricity supply during hours with a high power demand. PtH helps balance excess RES with flexible power consumptions. These effects reduce the gradients of the residual load profiles. Additional flexibility should also reduce the requirement for market-based *curtailment of renewable energy sources*, which is considered as a further indicator [15].

Retrofitting CHP plants and increasing PtH capacities are expected to affect the dispatch of power plants. The resulting changes in the *thermal and electrical generation mix* will translate into changes in *CO₂ emissions*. These indicators are analyzed for Germany, as well as for the remaining geographical scope, to assess the effects on import balances. Due to the focus on CHP and the ambiguity of allocating CO₂ emissions of CHP plants to the heat and power sectors, we only analyze the sum of CO₂ emissions for both sectors (e.g., [67]).

The additional flexibility (as well as the increased efficiency of modern CHP plants compared to their older counterparts) is expected to reduce overall system costs. *Overall variable generation costs* for all models and *investment costs* for models that include endogenous investments (EMM, DIM, and SCO) are analyzed. From a political perspective, the monetary benefits that result from introducing a technological option (i.e., retrofitting CHP plants or

¹⁰ The residual load (RL) after the utilization of CHP units and PtH for time step t is calculated as follows:
 $RL_t = Total\ load_t - Wind\ infeed_t - PV\ infeed_t - CHP\ generation_t + PtH\ consumption_t$.

increasing PtH capacities) can serve as the basis for potential financial support mechanisms to incentivize the respective option.

3 Results

This section presents and discusses the results. Subsection 3.1 focuses on thermal and electricity generation for the reference scenario, the coal replacement scenario, and the power-to-heat scenario. The two policy scenarios are analyzed in more detail afterward: first, we focus on the impacts on thermal and electricity system flexibility (Subsection 3.2) and second, on the role of CHP and PtH in reducing CO₂ emissions and system costs (Subsection 3.3). Emphasis will be placed on the results for the year 2030. Where relevant, the results for the year 2016 will also be discussed.

3.1 Generation mix

The results regarding thermal and electricity generation are summarized in Figure 4 and Figure 5. The generation is displayed for each model, disaggregated by fuel and turbine type. Moreover, the second level of the x axis gives information on the detail of the heat network modeling (granular to aggregated). In this section, the focus is on the impact of both mid-term policies on the generation mix in Germany and the corresponding cross-border interactions.

3.1.1 Development of the thermal generation mix

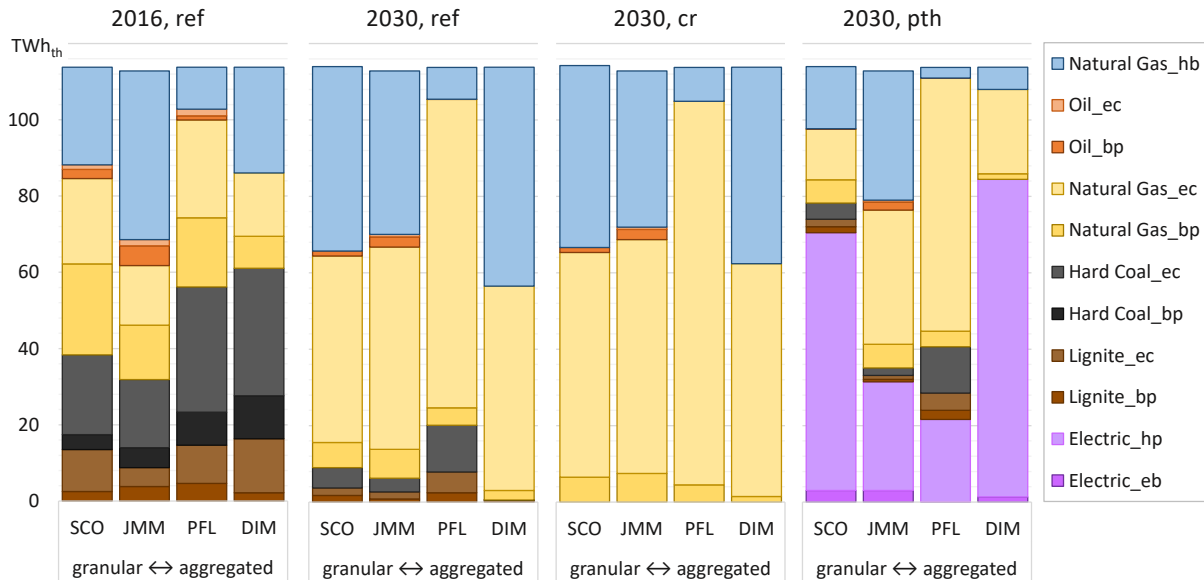


Figure 4: Thermal generation in Germany for the years 2016 and 2030

Comparing the thermal generation in the reference scenario (ref) for 2016, we obtained comparable results from two groups of models with similar detail in CHP modeling (see Figure 4).¹¹ The first group (JMM and SCO) shows a lower generation from coal-fired CHP units and

¹¹ Recall that the EMM does not contain a heat balance equation, which is why no thermal generation is reported.

higher utilization of gas-fired units and fossil heat boilers. Both models use a detailed approach to depict CHP units and their respective heat networks, resulting in a more restrictive dispatch of heat supply units. Hence, high variable cost units, such as heat boilers and gas turbines, must be deployed when the generation capacity in a specific heat network is scarce. The second group of models (PFL and DIM) aggregates heat demand, allowing for a less restrictive dispatch of heat supply units. That is why both models show a higher generation from coal and lignite CHP plants and a lower utilization of heat boilers. This effect is amplified by the relatively low CO₂ price in 2016 (5.2 EUR/tCO₂). For the year 2030, the results are more homogenous (see “2030, ref” in Figure 4). The significantly higher CO₂ price and the decommissioning of coal and lignite (and gas-fired backpressure) plants due to their end of lifetime lead to a substitution of coal- and lignite-fired heat supply by natural gas, in particular by natural gas extraction-condensing turbines (see also [57], [58]). Again, the SCO and JMM delivered comparable results. However, the heat supply from coal and lignite is more pronounced in the SCO, as heat demand is pre-allocated to individual heat systems instead of regional heat networks, limiting a substitution between coal and gas. The PFL and DIM, on the other hand, showed more considerable differences compared to 2016 and to the other models. In the DIM, coal and lignite CHP plants are endogenously decommissioned until 2030, and heat supply is entirely provided by natural gas, as CO₂ prices increase and natural gas becomes the more cost-efficient source of heat provision. The PFL shows the highest remaining heat generation from coal and lignite. This is caused by the pre-allocation of heat demand to fuel-specific heat balances, which limits the substitution of heat generation from coal with heat generation from natural gas.

In the coal replacement scenario (cr), coal- and lignite-fired thermal generation is reduced further in all models compared to the reference scenario. This can be attributed to the exogenous replacement of coal and lignite plants by natural gas extraction-condensing units as part of the mid-term strategy, leading to a higher generation from natural gas (compare “2030, ref” and “2030, cr” in Figure 4). The DIM shows no considerable impact of coal replacement, as the decommissioning of coal and lignite CHP plants already takes place endogenously in the reference scenario, driven by the high CO₂ price. In line with the results for the reference scenario, the SCO and JMM, which both feature a high resolution of thermal system modeling, again deliver somewhat similar results. In addition, thermal generation from heat boilers is mostly reduced, which is further discussed in Section 3.2.

PtH technologies cover a considerable share of the heat demand in the power-to-heat scenario (pth), replacing thermal generation from natural gas extraction-condensing turbines and fossil heat boilers. Regarding the considered PtH technologies, mainly large-scale heat pumps are utilized in all models (see “2030, pth” in Figure 4). Two models (SCO and DIM) show a higher

utilization of PtH technologies compared to a lower utilization in the JMM and PFL. These differences can be traced back to endogenous investments and hence the model types—dispatch-only vs. investment (see Section 2.1). In general, the provision of PtH increases electricity demand and therefore scarcity in electricity markets, resulting in higher electricity prices. As dispatch-only models do not allow for endogenous investment, they calculate the dispatch for an exogenously given power plant fleet. In contrast, investment models allow for endogenous investment in new generation units (including RES), adapting to the increased electricity demand by PtH technologies. That is why electrical capacity is scarce in the dispatch problem. In the case of the displayed PtH scenario, both investment models (SCO and DIM) increase the capacity of RES (mainly wind) outside of Germany, as the market value of RES increases with higher electricity prices (see Appendix A). The DIM, moreover, shows an even higher thermal generation from PtH technologies compared to the SCO, which is due to the less restrictive modeling of heat networks (compare with Section 2.2). Regarding the utilization of heat boilers, all models predict a significant decrease, indicating the benefits of PtH concerning thermal flexibility. For a detailed analysis, see Section 3.2.

3.1.2 Development of the electricity generation mix

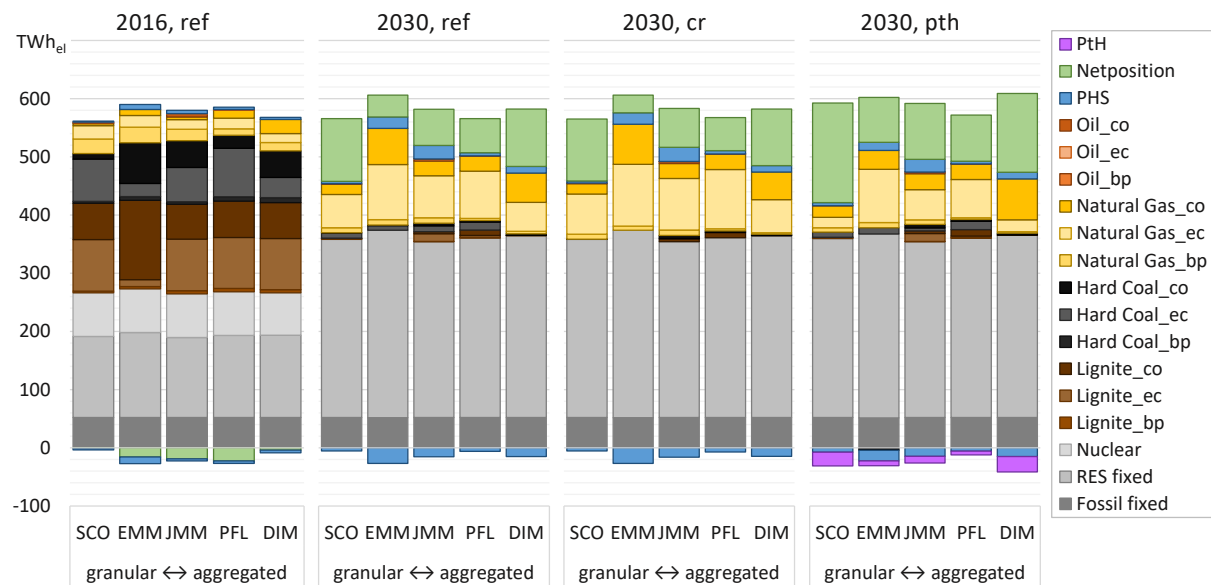


Figure 5: Electricity generation and consumption and net position in Germany for the years 2016 and 2030¹²

Changes in the thermal generation mix are linked to adjustments in the electricity generation. For the reference scenario, all models yield comparable results with regard to the utilization of base-load power plants and net position (export) in 2016¹³ (see Figure 5). Moving forward to the year 2030, the exogenously increased share of RES, the higher CO₂ price, and the

¹² Note that other fossils and non-renewable waste are summarized under “Fossil fixed,” while wind, solar, bioenergy, and renewable waste under “RES fixed.”

¹³ In the EMM, the high share of condensing units is caused by the CHP modeling, where only the minimum heat generation is reported under extraction-condensing and the remainder is allocated to condensing.

decommissioning of coal-fired power plants lead to an increased utilization of gas-fired generation units and higher imports. The main differences can be attributed to the modeling of endogenous investments. While the dispatch-only models (JMM and PFL) still show some electricity generation from coal and lignite plants, the investment models (EMM, DIM, and SCO) substitute this supply almost completely by natural gas. The additional endogenous decommissioning of coal and lignite plants in the DIM and EMM is balanced by generation from new gas-fired condensing units. The high imports to Germany in the DIM and SCO are due to investments mainly in wind power outside of Germany (see Appendix A).

When replacing coal-fired CHP units with modern gas-fired CHP units, all five models agree on an increased generation from gas-fired replacement units (extraction-condensing) reducing coal-fired CHP must-run. However, two groups of models can be identified with regard to further impacts. In the JMM and PFL, the overall electricity generation in Germany decreases slightly, and coal replacement is partly substituted by additional imports. In contrast, the SCO, EMM, and DIM find a slight increase in the overall generation driven by the more efficient gas-fired CHP units, which is why imports decrease. Due to the endogenous decommissioning of coal-fired generation units in the reference scenario, the overall impact of coal replacement is, however, limited in the EMM and DIM.

With the provision of heat mainly by large-scale heat pumps, additional electricity consumption increases the electricity demand by up to 5%. In general, all five models agree that this additional electricity consumption is provided by increased net imports. Driven by increased endogenous RES investments and a higher utilization of PtH, the investment models (SCO, EMM, and DIM) find a correspondingly higher increase in imports to Germany. Moreover, the supply of heat by PtH reduces the electricity generation from CHP units, mainly natural gas-fired extraction-condensing units, in all models.

3.2 Thermal and electricity system flexibility

Both the replacement of existing coal-fired CHP units with innovative gas-fired CHP units and the integration of PtH are expected to contribute to the provision of flexibility. In this subsection, the three scenarios are compared for all five models regarding thermal system flexibility and electricity system flexibility.

The use of fossil heat boilers indicates a need for thermal flexibility that is not supplied by conventional CHP units, such as backpressure and extraction-condensing power plants. Since heat boilers are not restricted by the combination of power and heat, they are mainly utilized when flexibility is needed and the operational limits of available CHP units are reached. The utilization of heat boilers is expected to decrease when the capacity of modern flexible CHP units is increased (cf. coal replacement scenario) or when other flexible heat producers enter

the heat market (cf. power-to-heat scenario). As shown in Figure 6, both policy scenarios contribute to thermal system flexibility. However, the expected reduction differs quite substantially in magnitude between the models. In contrast to the JMM, the considerable reduction in heat boiler utilization in the SCO and DIM in the power-to-heat scenario is driven by RES investments outside of Germany (cf. Figure 14) and the resulting higher heat supply from PtH (cf. Figure 4). The PFL shows a slight increase in fossil heat boiler utilization in the coal replacement scenario. Heat boilers are used when heat demand is high and the availability of gas CHP plants is low, an effect that increases when replacing coal-fired with gas-fired CHP plants.

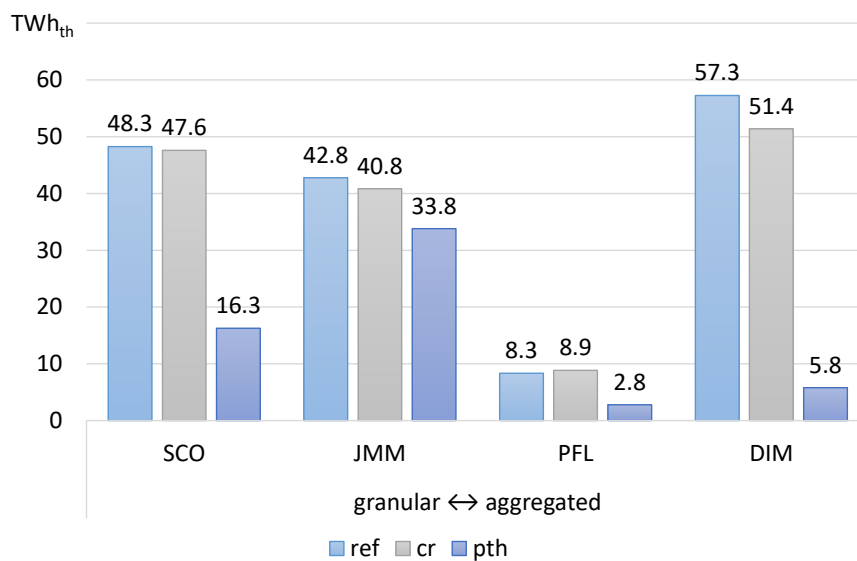


Figure 6: Utilization of heat boilers in Germany for the year 2030

When electricity storage is full and demand is inflexible, excess infeed from variable RES needs to be curtailed to maintain the balance between supply and demand in a power system. Inflexibilities, such as technical restrictions on conventional generation units (e.g., minimum operation times, minimum downtimes, ramping constraints, or CHP must-run), can amplify this effect. Consequently, modern flexible CHP units with increased product flexibility (i.e., adapting the ratio between heat and electricity) are expected to reduce CHP must-run generation and the need to curtail RES in situations with excess infeed improving the integration of RES. Figure 7 presents the resulting market-based RES curtailment per model for all three scenarios. The JMM and PFL find a reduction in RES curtailment in both scenarios compared to the reference scenario. The reduction in the coal replacement scenario results from the higher product flexibility of the replacement units, as discussed above. The more significant reduction for PtH is based on the use of excess electricity from variable RES by electric boilers and heat pumps. The EMM's counterintuitive result that the German curtailment increases is over-compensated by decreasing curtailment in France, Belgium, and the Netherlands—

therefore, the coal replacement policy decreases the overall curtailment across the model scope in the EMM as well. In the DIM, the decrease in RES stays roughly the same. This is due to the already higher degree of flexibility in the reference scenario, as coal and lignite power plants are endogenously replaced by flexible gas power plants. For the SCO, no market-based RES curtailment is observed, which is a result of other flexibility options, such as consumption from pumped hydro storages or exports, thus balancing the above-mentioned inflexibilities.

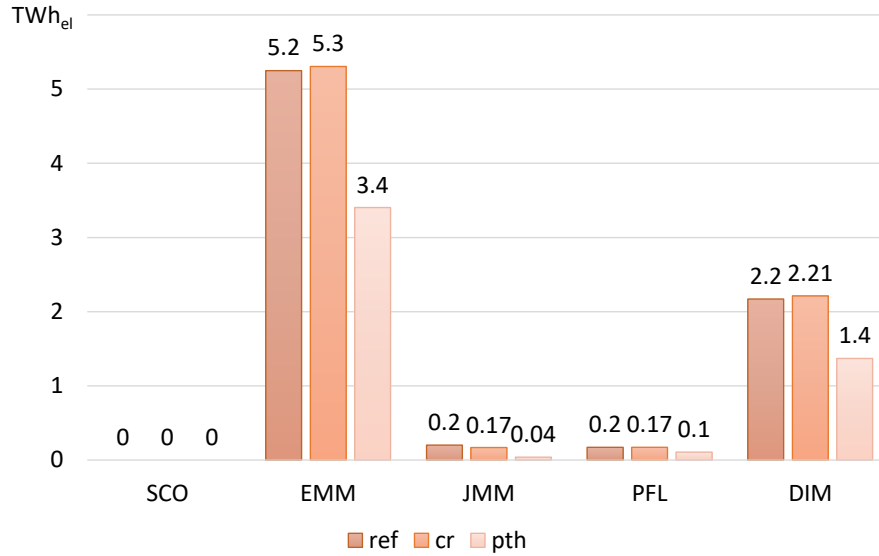


Figure 7: Market-based curtailment of RES in Germany for the year 2030

Figure 8 presents the adjusted hourly residual load¹⁴ for the power-to-heat scenario, as defined in Subsection 2.3, for the week with the highest original residual load¹⁵ over the year, which is the same for all models.¹⁶ The residual load is presented before (dotted lines) and after (bold lines) the subtraction of CHP generation to highlight the influence of CHP-related power generation. For the power-to-heat scenario, almost all models show periods with an increase in the power demand when the residual load is low (see differences between ref and pth at local minima in Figure 8). This indicates that the utilization of PtH technologies is intensified and that the variation of the residual load is reduced in times of high renewable infeed (i.e., times with low electricity prices flattening the load curve). Furthermore, the substitution of conventional heat from CHP units by PtH technologies increases electricity imports as the electricity production of CHP units is reduced (cf. Subsection 3.1). The effect is more obvious for the profiles after subtracting CHP generation, since PtH directly substitutes thermal CHP generation and hence reduces the power generation of CHP units. The EMM, JMM, and PFL show this effect, especially in times of lower (or negative) electricity demand compared to the

¹⁴ $RL_t = Total\ load_t - Wind\ infeed_t - PV\ infeed_t - CHP\ generation_t + PtH\ consumption_t$

¹⁵ $RL_t = Total\ load_t - Wind\ infeed_t - PV\ infeed_t$

¹⁶ The profiles of the residual load for the coal replacement scenario can be found in Appendix B.

reference scenario, whereas for the DIM and SCO, the increase is obvious even in times of higher load.

In order to analyse the impact on flexibility requirements, the change in the standard deviation of residual load before and after consideration of CHP generation is analyzed and compared with the reference scenario (see Figure 9). Consequently, a reduced standard deviation after CHP indicates a reduced need for flexibility caused by CHP itself and vice versa. Note that by definition, the residual load does not change before the subtraction of CHP production for the coal replacement scenario. All models agree that PtH provides additional flexibility to the electricity system and reveal a decreased standard deviation of the residual load before CHP (see upper graph in Figure 9). The observed model differences can be attributed to the granularity of CHP modeling and the representation of heat networks. Consequently, the more restricted modeling of CHP constraints in the SCO, EMM, and JMM leads to a higher need for thermal flexibility and hence a higher impact of PtH on electricity system flexibility before CHP. After consideration of CHP generation, the results become more heterogeneous. In the coal replacement scenario, the dispatch-only models (JMM and PFL) now find an increase in flexibility requirements. This can be explained by the exogenously reduced electrical capacity of the gas-fired replacement units, leading to a decrease in the overall electricity generation in Germany and compensation with additional imports (see also Section 3.1). In the power-to-heat scenario, the dispatch-only models (JMM and PFL) find an even stronger decrease in flexibility requirements, whereas the investment models predict a decreased impact (SCO and EMM) or even the opposite effect of PtH (DIM). This can be attributed to additional RES investments outside of Germany, the resulting interactions with cross-border exchanges, and a decreased utilization of CHP units in the investment models (see also Section 3.1).

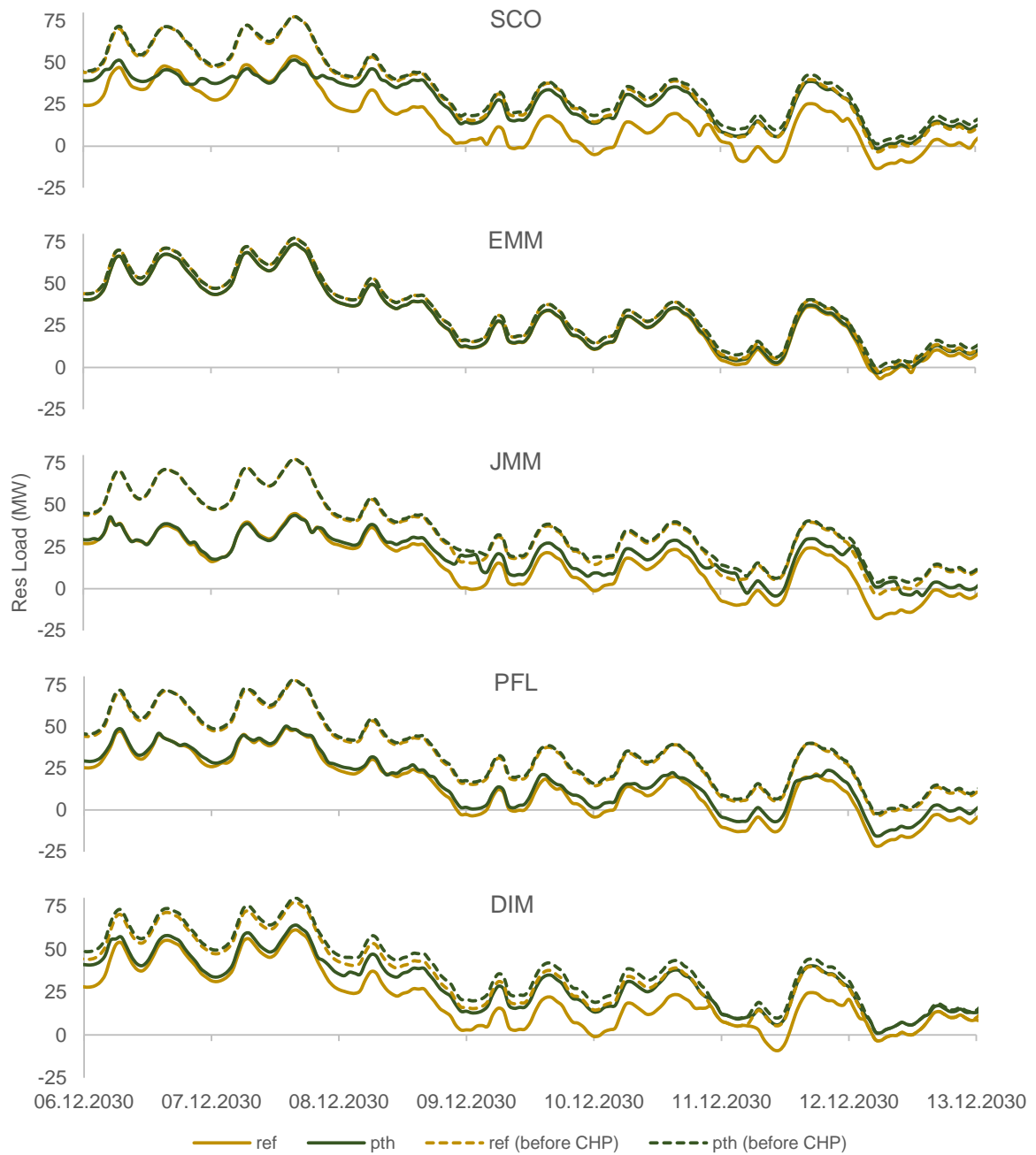


Figure 8: Profiles of the residual load for the ref and pth scenarios before and after conventional CHP generation for the week with the highest residual load¹⁷

¹⁷ In the EMM, the relatively smaller differences between the scenarios are caused by the differences in CHP modeling and reporting of results (i.e., accounting for the heat generation of extraction-condensing units).

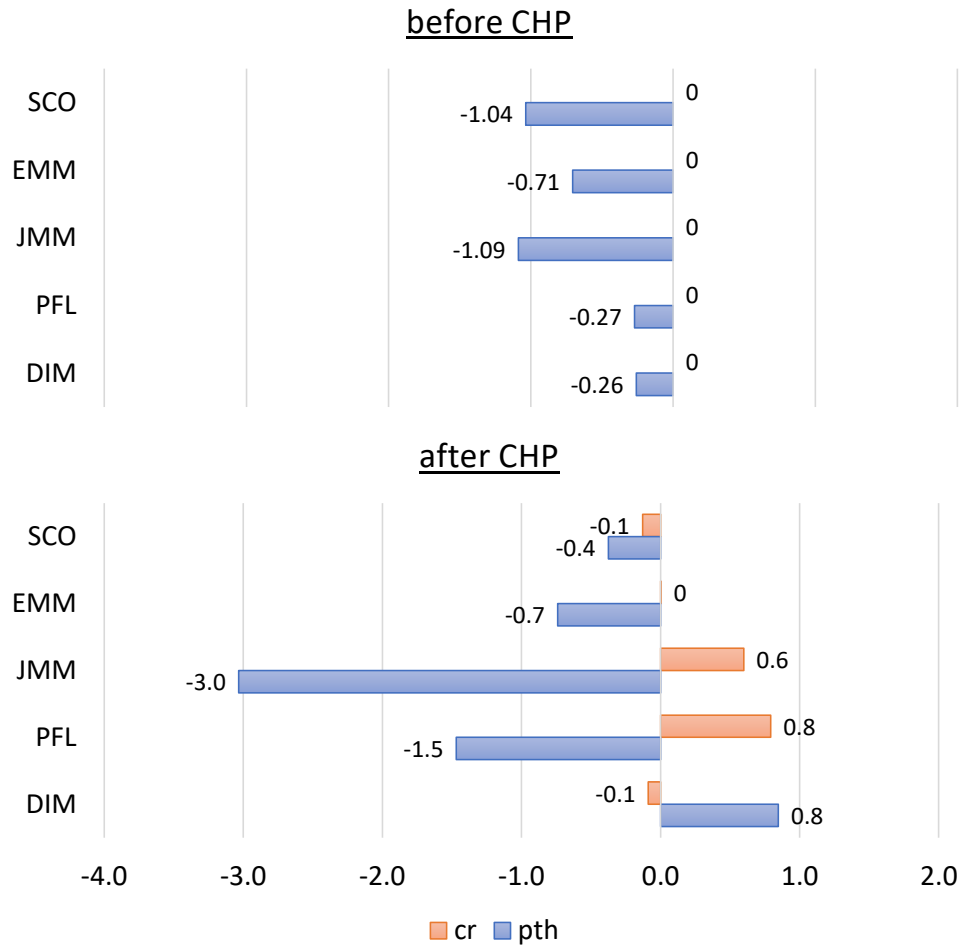


Figure 9: Change in the standard deviation of the residual load compared to ref

3.3 CO₂ emissions and system costs

The analyses of the coal replacement and power-to-heat scenarios have revealed considerable impacts on the generation mix and flexibility requirements. As a next step, we will discuss the resulting impacts on CO₂ emissions and system costs, which are expected to mirror the effects observed above. In the following, the focus will be on the potential benefits at the national and European levels.

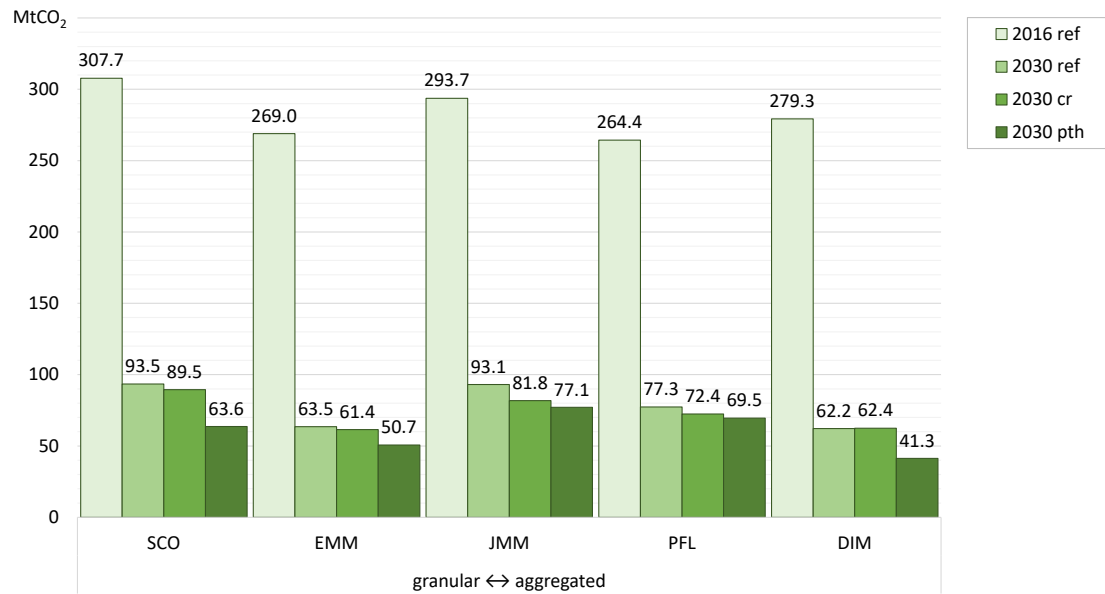


Figure 10: CO₂ emissions for Germany

Figure 10 depicts the absolute CO₂ emissions of the reference scenario and the two policies considered for Germany. The reduction in emissions from 2016 to 2030 can be mainly attributed to the increased CO₂ price, the exogenous additions of RES, the age-related exogenous decommissioning of CO₂-emitting technologies, and the corresponding changes in the respective generation mix. All models agree with the finding that both the coal replacement and PtH strategies lead to a further decrease in national CO₂ emissions. The magnitude of the effect, however, varies significantly between models (in a range from 2.1 to 29.9 MtCO₂). Figure 11 shows the net effect on CO₂ emissions at the European level of the coal replacement and power-to-heat scenarios disaggregated by the national effect (DE) and the waterbed effect (i.e., the effect outside of DE). For the coal replacement scenario, all models consider an overall reduction in emissions (see net effect in Figure 11). The DIM reports a low impact on emissions mainly driven by the additional (endogenous) decommissioning of coal-fired generation units already present in the reference scenario. The JMM and SCO find an increase in emissions outside of Germany as the reduced must-run generation from coal-fired CHP units in Germany is replaced by imports and an increased generation from fossil-fired technologies in neighboring countries. The decrease in emissions in neighboring countries predicted by the EMM is driven by a higher generation from modern CHP units in Germany and a corresponding increase in exports (see also Figure 5).

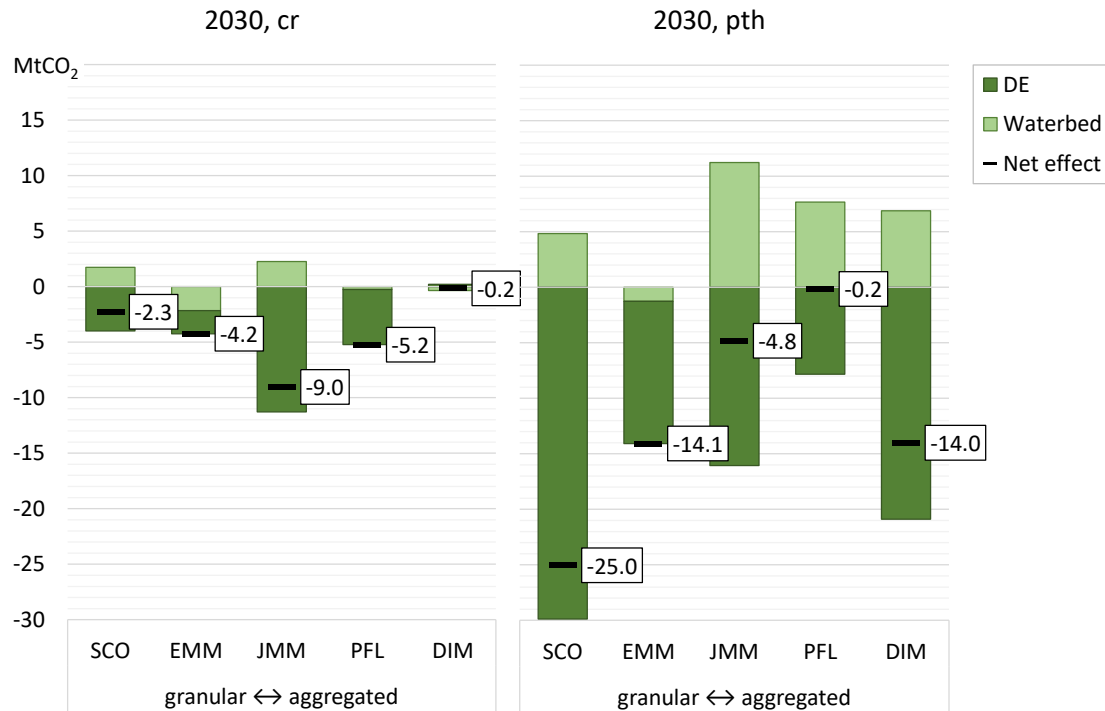


Figure 11: Change in CO₂ emissions for the year 2030

For the power-to-heat scenario, all five models yield a reduction in emissions in Germany. However, while all models agree that PtH and the corresponding additional power demand lead to increasing imports, they disagree on the size and even direction of the waterbed effect. This is mainly driven by modeling differences regarding CHP and endogenous investments. The dispatch-only models (JMM and PFL) show the highest increase in emissions outside of Germany, as additional generation is provided by existing conventional power plants. In the JMM, the effect is more pronounced due to the tighter constraints in the CHP modeling. In the investment models (SCO, EMM, and DIM), RES investments outside of Germany contribute to a reduction in emissions. In the EMM, this effect actually overcompensates increasing emissions due to conventional generation, which leads to a negative waterbed effect (see also Figure 14).

Both coal replacement and PtH lead to changes in the generation mix, the provision of flexibility, and CO₂ emissions. These changes also affect the integrated electricity and heat systems from an economic perspective. In the following, we analyze the impact on variable system costs at the European level,¹⁸ again disaggregating the national effect (DE) and the waterbed effect. For the coal replacement scenario, most models find an increase in system costs in Germany (EMM, DIM, PFL, and SCO), which are partly compensated by cost reductions outside of Germany caused by an increase in exports or a decrease in imports (EMM, PFL, and DIM). In contrast, the JMM considers a decrease in system costs in Germany, while the substitution of must-run generation from replaced coal-fired CHP units outside of

¹⁸ For a discussion of the impacts on investment costs, see Appendix A.

Germany leads to increased imports and a positive waterbed effect. With regard to the net effect, the SCO, JMM, PFL, and DIM report an increase in overall system costs, whereas the EMM finds a decrease. In the latter case, exogenous coal replacement leads to a stronger decrease in imports to Germany, overcompensating the cost increase in Germany.

The changes in variable system costs in the power-to-heat scenario mirror the effects on CO₂ emissions (see right graph in Figure 12). Likewise, all models find a decrease in system costs in Germany as PtH substitutes the heat supply from gas-fired CHP units and heat boilers. Regarding the waterbed effect, the dispatch-only models (JMM and PFL) find an increase in costs driven by the additional electricity consumption of PtH associated with increased imports. As described above, the effect is more pronounced in the JMM due to the tighter constraints in the CHP modeling. In the investment models (SCO, EMM, and DIM), investments in wind power outside of Germany contribute to a reduction not only in emissions but also in system costs. However, in the DIM and SCO, the increased generation from natural gas outside of Germany overcompensates this effect. Overall, PtH contributes to a reduction in variable system costs.

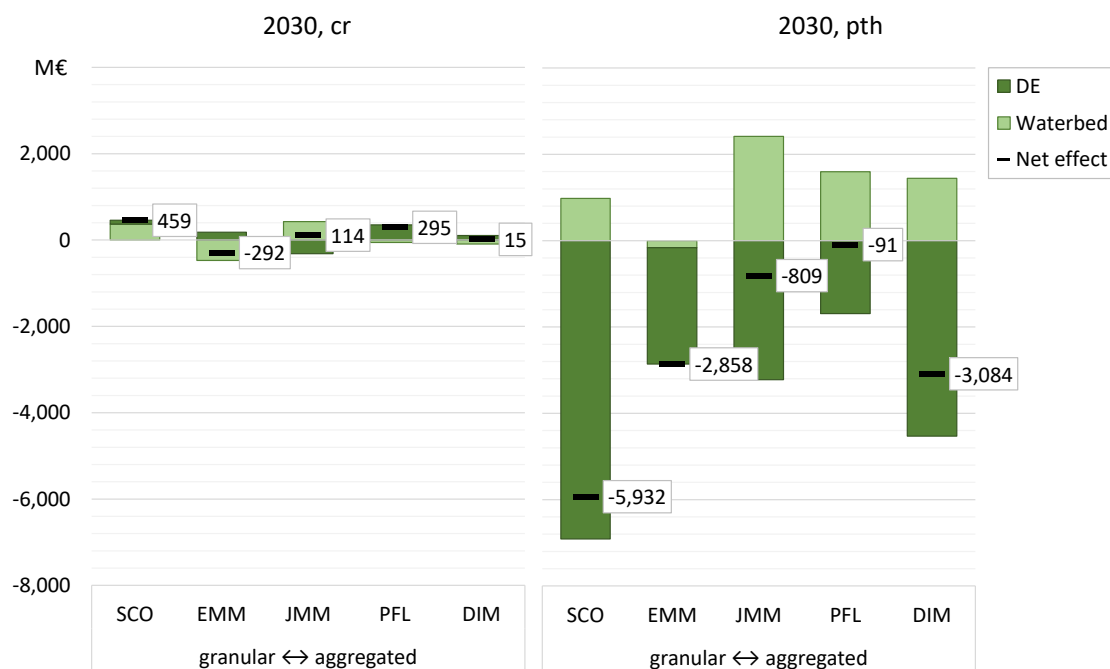


Figure 12: Change in variable system costs (net effect indicated by numbers)

4 Discussion and conclusions

In this model comparison experiment, five models covering the integrated European electricity and heat system were utilized to evaluate two mid-term transformation strategies for the year 2030—namely, replacing old coal-fired with new gas-fired CHP units and electrifying district heating through complementary heat pumps and electrode boilers. The focus was placed on the effectiveness of the two mid-term policies in the context of flexibility provision, emissions reduction, and economic efficiency. While the models agree on the qualitative effects, there are considerable differences in quantification. For example, the estimated reductions in overall CO₂ emissions range between 0.2 and 9.0 MtCO₂/a for coal replacement and between 0.2 and 25.0 MtCO₂/a for electrification.

Two main reasons for these differences in the model results are the level of detail of CHP modeling and the endogeneity of generation capacity. For example, fuel-specific heat balances in the PFL require an ex ante allocation of heat demand to different fuels, which limits price-driven substitution between fuels. Likewise, in the SCO and EMM, the allocation of heat demand to single heat supply systems or vintages limits potential substitution effects, mainly between coal- and gas-fired CHP units. On the other hand, the country-wise aggregation of heat demand in the DIM may lead to an overestimation of the substitution of coal-fired generation. This effect might even be amplified by endogenous investments and decommissioning. The allocation of CHP units to regional heat networks in the JMM addresses this trade-off in a suitable way. However, missing features of the JMM, such as endogenous investments and decommissioning, might contribute to an underestimation of substitution effects.

Despite the differences, our results reveal the potential system benefits of CHP and confirm the implications stated in other contributions (e.g., [12], [15], [25]–[28]). Accordingly, both considered policies contribute to thermal system flexibility by reducing the use of heat boilers. This can be attributed to higher product flexibility—that is, adapting the ratio between heat and electricity of modern gas-fired CHP units—and to the contribution of PtH to hours with a high heat demand. The PtH scenario provides flexibility to the electricity system (i.e., load shifting and coping with the variability of demand and RES), whereas the coal replacement strategy increases flexibility requirements in the dispatch-only models. By contrast, the coal replacement strategy is found to decrease flexibility requirements in models that also consider endogenous investments and related impacts on cross-border changes. Moreover, all models agree that PtH contributes to the integration of variable RES as the market-based curtailment of wind power in particular is reduced. Under both transformation policies, all models report a reduction in overall CO₂ emissions, whereas they disagree on the waterbed effect, mainly due to modeling differences regarding CHP and endogenous investments. For example,

endogenous investments in wind power driven by a higher market value under the PtH scenario allow for a stronger decrease in emissions. While the coal replacement leads to an increase in variable system costs, all five models agree that PtH reduces these costs. In the latter case, the cost reductions are higher in the investment models, which balance the additional electricity consumption of PtH with investments in wind power.

This model comparison experiment demonstrates that modeling choices strongly impact the extent of the benefits provided by the considered transformation strategies. On the one hand, technical restrictions related to CHP can substantially hinder decarbonization, and an omission of these restrictions in the modeling may lead to an overly optimistic assessment of decarbonization strategies. On the other hand, modeling endogenous investment and decommissioning captures adaptations to the transformation strategies of combined heat and power systems that are immanently neglected by dispatch-only models. These adaptations include additional investments in RES and the shutdown of conventional generation units, which amplify the positive implications of CHP decarbonization strategies.

Modelers and decision makers should be aware of the potential limitations of the chosen modeling approach and the resulting uncertainty with regard to the impacts of transformation strategies. Moreover, this model comparison experiment reveals a number of implications for policy makers. First, a high CO₂ price already leads to a reduced utilization of coal-fired CHP units and their partial decommissioning in the reference scenario. This demonstrates the effectiveness of CO₂ pricing for the decarbonization of integrated electricity and heat systems [58]. Second, the electrification of the heat sector through PtH should be aligned with national expansion targets for RES to respond to Germany's increased import dependency. Moreover, the European perspective should be taken into account in order to consider cross-border interactions and ensure an electrification that is in line with the climate targets.

Acknowledgements

We thank Christoph Weber for his valuable comments and interesting discussions. Furthermore, we gratefully acknowledge funding from the German Ministry of Economics and Technology (BMWi) within the MODEX-POLINS project (grant number 03ET4075).

Data availability

Relevant input data with regard to time series and capacities are available upon request.

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Appendix A: Further results of the investment models

Figure 13 provides a direct view of endogenous investment and decommissioning in capacity terms in Germany for the year 2030. While the SCO does not feature any capacity changes in Germany, endogenous investments in the EMM and DIM are related to natural gas. This contrasts with the decommissioning of coal-fired generation units driven by the assumed CO₂ price of 87 EUR/tCO₂. In the EMM, the constraint maintaining a constant CHP capacity partly balances the observed investment and decommissioning decisions. In the DIM, the higher investments in gas-fired generation units are driven by a peak constraint imposing a minimum electrical capacity due to security-of-supply reasons. Under the coal replacement scenario, the exogenous replacement of coal-fired generation units reduces endogenous decommissioning in the EMM and DIM. Moreover, the exogenous addition of modern gas-fired CHP units pushes less efficient gas units out of the market and reduces the need for endogenous investments. Under the power-to-heat scenario, the EMM finds slightly lower decommissioning of conventional generation units due to a higher price level and profitability of coal-fired generation units. In the DIM, PtH leads to a decommissioning of CHP units, which is however balanced with additional investments in gas-fired generation units due to the peak constraint. At the European level, most endogenous investments are related to wind power impacting electricity prices and cross-border exchanges with Germany (see Figure 14 and Section 3.1). While for the coal replacement scenario, there is no considerable change compared with the reference scenario, all investment models consider higher additions of wind power under the power-to-heat scenario. This is due to an increased electricity demand from PtH, which leads to higher electricity prices and increased market values of RES (see also Figure 15).

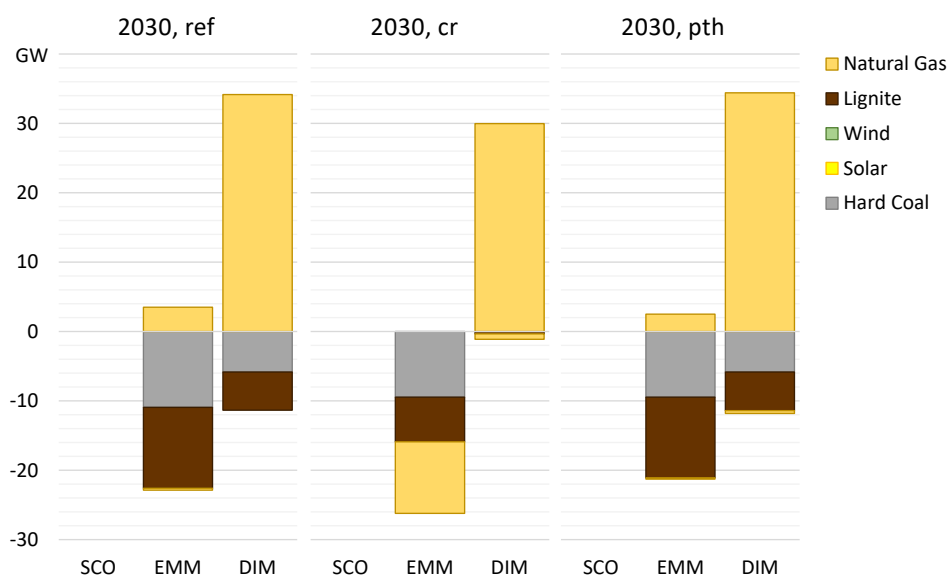


Figure 13: Endogenous capacity investment (positive values) and decommissioning (negative values) in 2030 in Germany

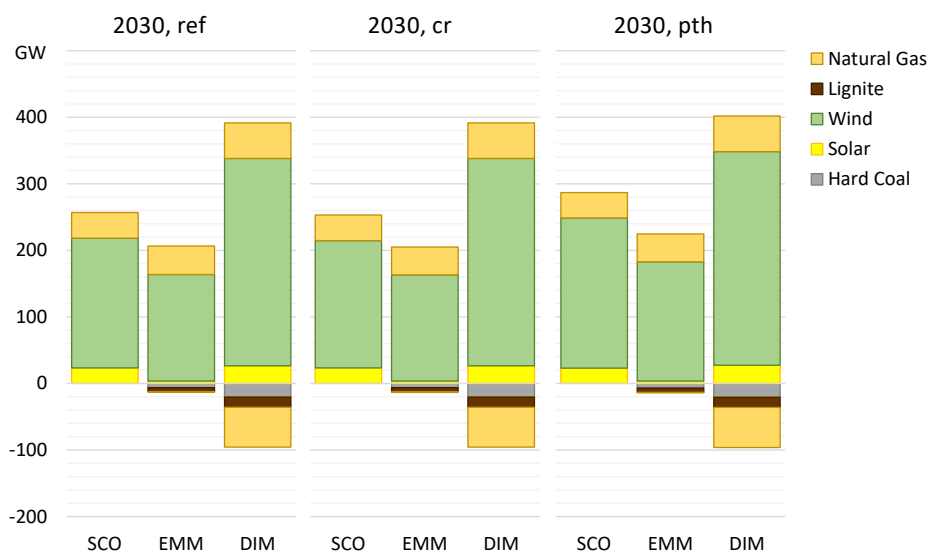


Figure 14: Endogenous capacity investment (positive values) and decommissioning (negative values) in 2030 in the remaining European countries included in the analysis

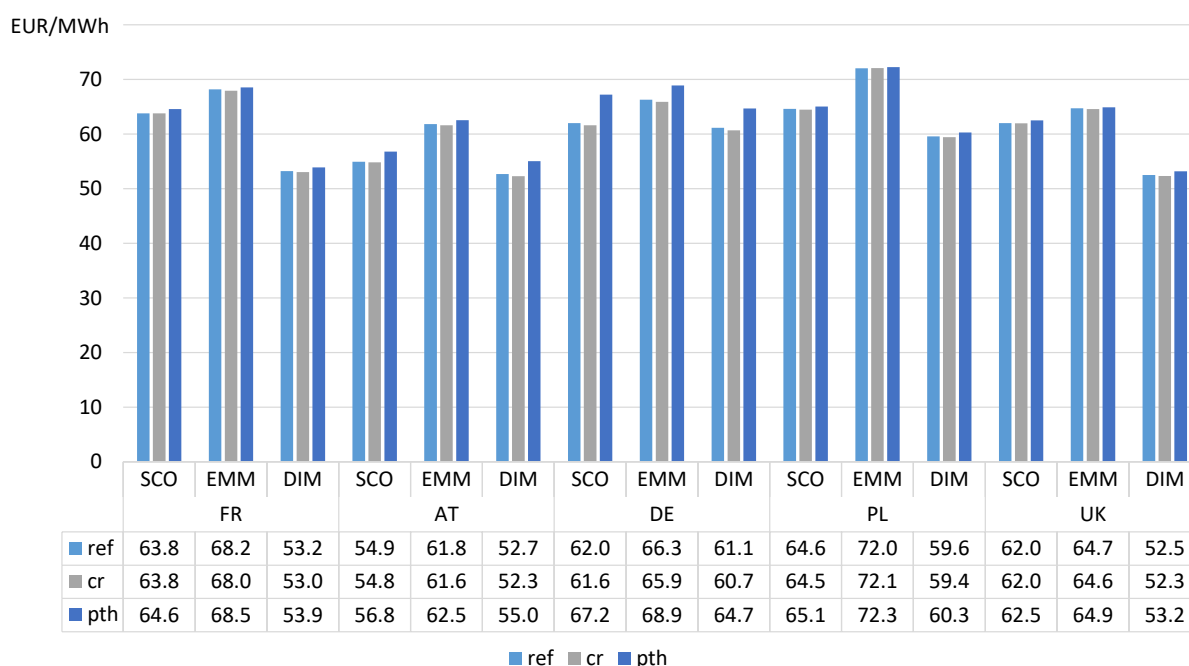


Figure 15: Electricity prices for Germany and selected countries with high investments in wind energy

Figure 16 shows the changes in investment costs for the coal replacement and power-to-heat scenarios compared to the reference scenario. Whereas the SCO does not report a considerable change in investment costs under the coal replacement scenario, the DIM and EMM find a reduction driven by exogenous replacement investments and related lower investment needs. In the power-to-heat scenario, all investment models consider supplemental investment costs driven by additional RES investments. Nevertheless, in all cases, the increased investment costs are overcompensated by decreased variable system costs. The increase in investment costs in DE in the DIM can be traced back to higher investments in

combined-cycle gas turbines, which become more economical with additional electricity demand from PtH.

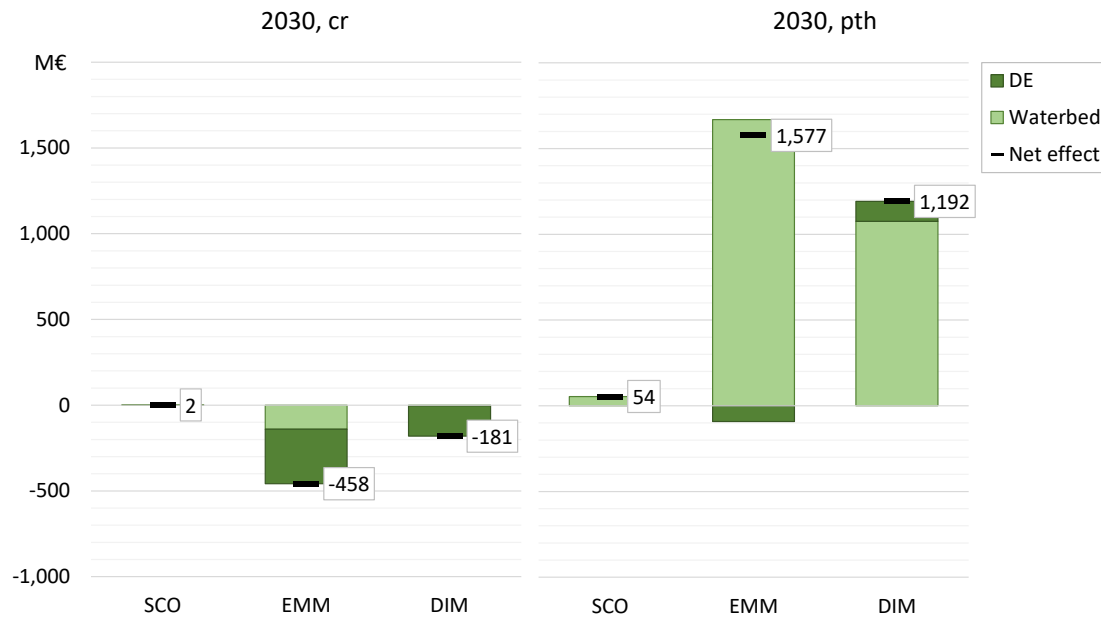


Figure 16: Change in investment costs (net effect indicated by numbers)

Appendix B: Profiles of the residual load for the coal replacement scenario

By definition, the residual loads of the ref and cr scenarios are identical before the subtraction of CHP production; consequently, this case is not displayed in Figure 17. For the case after the subtraction of CHP production, the models show only small deviations between the two scenarios. The SCO and JMM (and slightly the PFL) show an increase in residual load, even in the peak segments. This might even cause a higher demand for flexibility for the remaining conventional power units and can be explained by the decrease in CHP capacity caused by the implemented coal replacement heuristic. The thermal capacities are replaced one to one, but the related electrical capacities are reduced due to an increase in the adopted power-to-heat ratio. The DIM shows the opposite effect—a decrease in residual load. This is related to an additional increase in CHP capacity, which in turn increases power generation from CHP units.

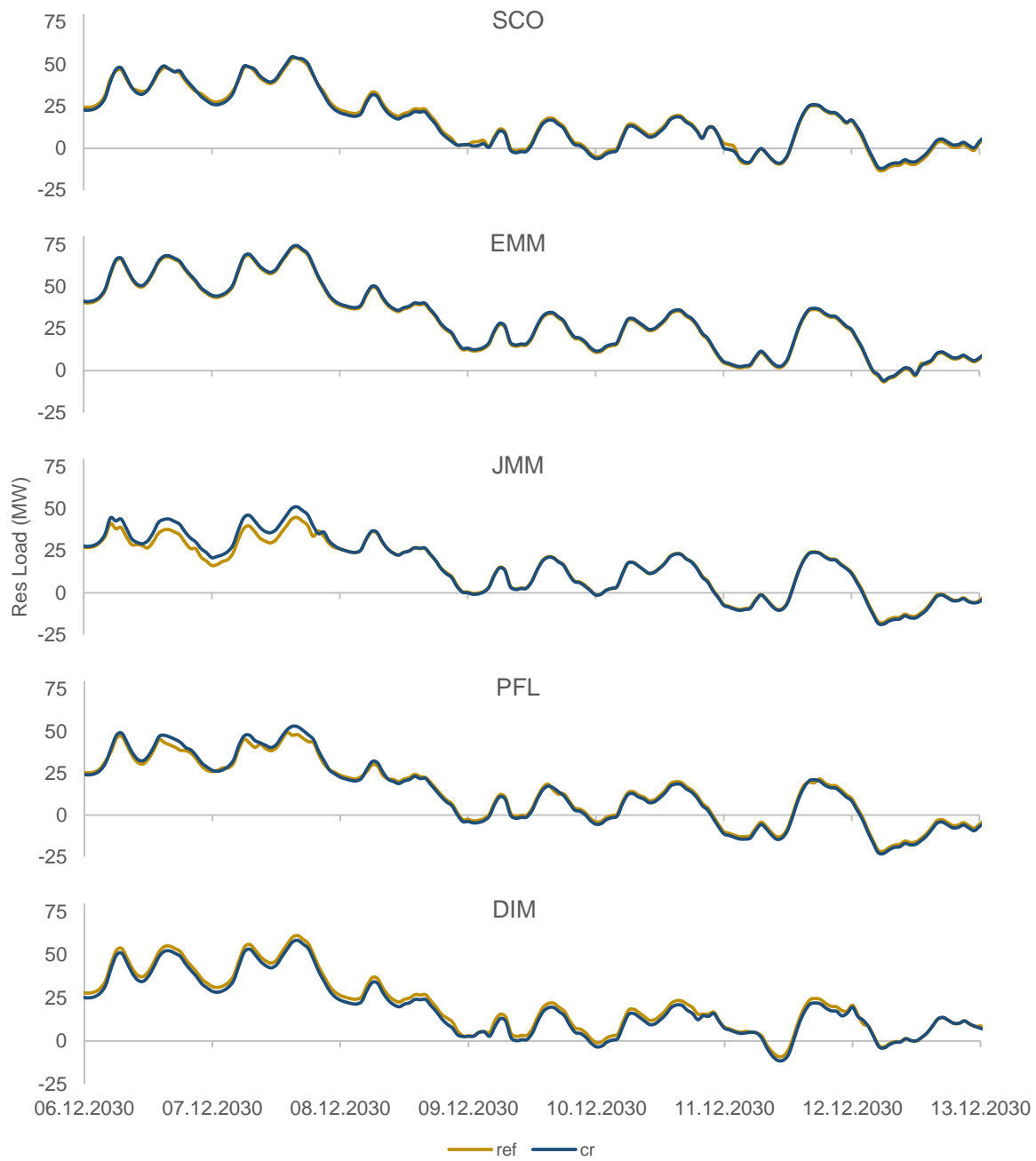


Figure 17: Week with the highest residual load for the ref and cr scenarios after conventional CHP generation