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**Working Paper**

## The European Electricity Market Model EMMA - Model Description

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The European Electricity Market Model EMMA

# Model Description

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## **This version: v1.0**

- Code repository: <https://github.com/emma-model/EMMA/tree/v1.0>

## **Latest version**

- Documentation: <https://emma-model.com/documentation>

- Code repository: <https://github.com/emma-model/EMMA>

Version note: This version is the new EMMA master version which comprises our learnings from the last two years of model development. Among other things, this new version entails the enhanced modeling of conventional power plants (vintages, cogeneration cycling), hydrogen technologies and a hydrogen balance, and a carbon constraint (in addition to carbon prices). Furthermore, the model architecture has been substantially revised, including the development of a jupyter-based dashboard. Most of the development was carried out within the **MODEX-POLINS** and **SENTINEL** research projects.

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# Table of Content

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Table of Content.....	2
1 Overview .....	3
2 Model Equations .....	8
2.1 Total System Costs .....	8
2.2 Electricity Balance .....	9
2.3 Hydrogen balance .....	10
2.4 Carbon Budget .....	11
2.5 Generation Capacity Constraints .....	11
2.6 Power System Inflexibilities.....	13
2.7 Flexibility Options.....	16
2.8 Balancing Costs .....	18
2.9 Alternative Problem Formulation.....	18
3 Notation .....	19
4 Input Data .....	20
5 Model Limitations .....	25
6 Applications.....	26
7 References .....	28

# 1 Overview

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**Summary.** The Electricity Market Model EMMA is a techno-economic model of the integrated European power system. It simulates investment, dispatch, and trade, minimizing total costs subject to a large set of technical constraints. In economics terms, it is a partial equilibrium model of the wholesale electricity market. It calculates scenario-based or green-field optima (equilibria) and estimates the corresponding capacity mix as well as hourly prices, generation, storage dispatch, flexible consumption, and cross-border trade for each market area. Technically, EMMA is a linear program, written in GAMS and solved by CPLEX on a desktop computer in about two hours. EMMA has been used for a number of peer-reviewed publications as well as in consulting projects. EMMA is open-source: the model code and input data are freely available under the [MIT Software License](#) and the [Create Commons BY-SA 4.0 License](#), respectively, and can be downloaded from <https://github.com/emma-model>.

**Objective function and decision variables.** For a given hour-by-hour electricity demand, EMMA minimizes total system cost, i.e., the sum of capital costs, fuel costs, and other fixed and variable costs of generation, transmission, and storage assets (see 2.1). Investment and generation are jointly optimized for one representative year. Decision variables comprise the hourly supply of each generation technology, dispatch of storage technologies and electrolysis, and electricity trade between regions, as well as annualized investment and disinvestment in each technology. Core constraints constitute the energy balance, capacity limitations, cogeneration of heat, and provision of ancillary services. Carbon emissions may be considered in the model through exogenous carbon prices or a constraint on total emissions. Decision variables and constraints are discussed in detail in subsections 2.2 to 2.8. Subsection 2.9 offers an alternative, equivalent problem formulation.

**Technologies.** Generation and storage are modeled as 19 discrete technologies with continuous capacity (Table 1):

- (i) **Three variable renewable energy sources** with near-zero marginal costs – onshore wind, offshore wind, and solar photovoltaics (PV). Hour-by-hour wind and solar generation are limited by exogenous profiles and can be curtailed at zero cost or at the opportunity cost of market premium subsidies.
- (ii) **Eleven thermal technologies and a generic “load shedding” technology.** The thermal technologies include nuclear power, two types of coal-fired power plants (lignite and hard coal), two types of natural gas-fired power plants (combined cycle gas turbines – CCGT, and open cycle gas turbines – OCGT), bioenergy-fired power plants (aggregated biomass, biogas, and renewable waste), three carbon capture and storage plants (lignite-fired with CCS, coal-fired with CCS, and gas-fired CCGT with CCS), and two hydrogen-fired plants (CCGT and OCGT). These

plants produce whenever the price is above their variable costs, except for bioenergy which is assumed to run constantly. For scenario-based analyses, up to three vintage classes with distinct conversion efficiencies are included per technology, in addition to one class per technology with newbuilt capacity. Load is shed if prices reach its opportunity cost (willingness to pay, value of lost load).

- (iii) **Five hydro power, storage, and hydrogen technologies.** Run-off-the-river hydro generation is exogenous based on historical patterns. Hydro reservoirs are optimized considering turbine and reservoir capacity, natural inflow, and minimum generation constraints. Pumped hydro power and batteries are subject to power and energy capacity constraints with possible capacity expansion. Likewise, investment and dispatch is optimized for hydrogen electrolyzers.

Depending on additional scenario-based restrictions, the model may invest in all technologies, except reservoir and run-off-the-river hydroelectricity, and bioenergy. Load shedding has no investment cost attached.

Table 1: Modeling of plant dispatch and investment

	Variable renewables	Thermal and load shedding	Hydro, storage, H2
<b>Fully endogenous (both dispatch and investment)</b>	<ul style="list-style-type: none"> <li>• Onshore wind</li> <li>• Offshore wind</li> <li>• Solar PV</li> </ul> (limited by generation profile)	<ul style="list-style-type: none"> <li>• Nuclear</li> <li>• Lignite (vin)</li> <li>• Hard coal (vin)</li> <li>• Natural gas CCGT (vin)</li> <li>• Natural gas OCGT (vin)</li> <li>• Lignite with CCS</li> <li>• Hard coal with CCS</li> <li>• Natural gas CCGT with CCS</li> <li>• Hydrogen CCGT</li> <li>• Hydrogen OCGT</li> <li>• Load shedding (zero investment cost)</li> </ul>	<ul style="list-style-type: none"> <li>• Pumped hydro</li> <li>• Batteries</li> <li>• Electrolysis</li> </ul>
<b>Dispatch endogenous, investment exogenous</b>			<ul style="list-style-type: none"> <li>• Reservoir hydro</li> </ul>
<b>Fully exogenous (both dispatch and investment)</b>		<ul style="list-style-type: none"> <li>• Bioenergy</li> </ul>	<ul style="list-style-type: none"> <li>• Run-off-the-river</li> </ul>

vin: vintages

**Investment decision.** EMMA can be used in two different setups which we call “long-term equilibria” and “scenarios”, respectively. The long-term equilibrium uses no legacy capacity (green field). Unlike the long-term equilibrium, the scenarios refer to specific years (2016, 2020, 2025, 2030, 2040, 2050) and hold specific assumptions on then-existing assets, fuel costs, and political constraints that may limit investment options (e.g. nuclear phase-out). The

scenarios can be distinguished into “short-term” runs (pure dispatch) and “mid-term” runs (capacity expansion / brown field). In short-term runs, all capacity is fixed. In mid-term runs, existing power plants are treated as sunk investment, but are decommissioned if they do not cover their quasi-fixed costs. New investments must recover their annualized capital costs from profits in the simulated year. Exceptions are run-off-the-river and reservoir hydro power as well as bioenergy, for which capacities are exogenously determined. Load shedding has zero investment cost. Endogenous interconnection investments are only allowed in long-term equilibrium runs. For more details see Table 2 and Section **Fehler! Verweisquelle konnte nicht gefunden werden.**

Table 2: Scenario and long-term modeling

		Short-term scenario (2016, dispatch only)	Mid-term scenario (2025, '30, '40, '50)	Long-term equilibrium (green field)
Existing capacity	Generation and storage	Yes	Yes (disinvestment possible)	No
	Interconnection	Yes	Yes (no disinvestment)	No
Investment	Generation and storage	No	Yes (with policy constraints)	Yes
	Interconnection	No	No	Yes

For hydro reservoirs, run-off-the-river and bioenergy, existing (legacy) capacity is always included and (dis)investments are never allowed. Existing capacity varies by scenario year (e.g. 2016, 2025, 2030).

**Spot price and capital costs recovery.** Since EMMA models one representative year, investment costs are included as annualized fixed costs. The hour-by-hour zonal electricity price is the shadow price of demand, or, as sometimes put in the engineering literature, the “system lambda”. The price can be interpreted as the prices of an energy-only market with scarcity pricing; we loosely think of it as the outcome of the day-ahead auction on coupled European wholesale markets. Such pricing guarantees that the zero-profit condition holds in the long-term equilibrium and there is no “missing money problem”.

**Electricity demand.** Historic demand is an exogenous input and assumed to be perfectly price inelastic but for very high prices, in which case load is shed. In addition, endogenous investment in hydrogen electrolyzers is explicitly considered. These are dispatched whenever the electricity price is below their hydrogen sales revenues per unit of electricity consumed. The annual margin of electrolyzers, which accumulates during hours when the electricity price is strictly below the electrolyzer dispatch price, covers their annualized investment cost (Ruhnau, 2021).

**Hydrogen balance.** As an alternative to exogenously specifying (possibly different) hydrogen prices for electrolyzers and hydrogen-fired gas turbines, the model offers the option to include regional hydrogen balances. In this case, the hydrogen price is the shadow price of the hydrogen balance. In addition, to domestic hydrogen production, imports are possible at a specified import price, and fixed exports (to other regions or sectors) can be considered. Note that, by contrast with the hourly electricity balances, we model hydrogen balances in with an annual temporal resolution. To account for storage and intra-regional transportation costs, we assume a price difference between buy and sell prices of hydrogen.

**Power system constraints.** Three important types of technical constraints on power plant flexibility are modeled: combined heat and power (CHP), system services, and thermal plant start-up. CHP power plants are constrained regarding their minimum and maximum generation, depending on the heat demand. A certain share of the cogenerating technologies (lignite, hard coal, CCGT and OCGT, including CCS and hydrogen-fired technologies) are forced to run even if prices are below their variable costs or to produce less electricity than full capacity even if prices are above their variable cost. The generation from the remaining capacity of these technologies is freely optimized. Investment and disinvestment in CHP generation is possible, but the total amount of electric CHP capacity must remain constant. System service provision is a function of peak load and VRE capacity, and it is modeled as a must-run constraint for dispatchable generators and batteries. Thermal plant start-up and shut-down (cycling) is captured by attaching a cost to hour-to-hour changes in generation. This approach implies bids above (below) variable costs for thermal technologies when generation needs to be increased (decreased) from one hour to another.

**Trade.** Cross-border electricity trade is endogenous and limited by net transfer capacities (NTCs). Investments in interconnector capacity are endogenous to the model (long-term equilibrium) or based on scenarios. Endogenous interconnector investments are made only if they reduce overall system cost. Within regions, transmission capacity is assumed to be non-binding.

**Carbon emissions.** EMMA calculates carbon emissions for the power sector. These can either be subject to an exogenously set carbon price or constrained by a given emission cap. In the latter case, the model calculates carbon prices as shadow prices of the emission constraint.

**Deterministic.** The model is fully deterministic. Long-term uncertainty surrounding fuel prices, investment costs, and demand development are not captured. Short-term uncertainty concerning VRE generation (day-ahead forecast errors) is approximated by imposing a reserve requirement via the system service constraint, and by charging VRE generators balancing costs.

**Geographical scope.** EMMA can be applied to different geographical scopes. Data is readily available for Austria, Belgium, Switzerland, Czech Republic, Denmark, France, Great Britain, German, The Netherlands, Norway, Poland, and Sweden.

**Solve time.** The model is written in GAMS and solved by CPLEX using a primal simplex method. The number of variables and constraints depends on the simulation setup, such as the countries modelled, and the features used. Calculating the dispatch and investment in 13 countries, for a whole year (8760 times steps) renders a model size of approximatively 35 million equations and 120 million non-zero elements. The solve time on a personal laptop (i7-8565U CPU and 40 GB RAM) for this setup is about 2 hours.

Table 3: Model input and output

Model input (assumptions)	Model output (results)
<ul style="list-style-type: none"> <li>• Installed capacity of generation, storage, interconnection (for scenario-based runs)</li> <li>• Investment costs and technical parameters of future generation, storage, interconnection</li> <li>• Fuel prices</li> <li>• Carbon prices or a cap on total emissions</li> <li>• Wind and solar generation potential (time series)</li> <li>• Electricity consumption (time series)</li> <li>• Power system constraints (balancing, CHP)</li> </ul>	<ul style="list-style-type: none"> <li>• (Dis-)investment in generation, storage, interconnection</li> <li>• Dispatch of generation, storage, interconnection</li> <li>• Cross-border trade</li> <li>• Electricity prices (day-ahead spot prices)</li> <li>• Carbon emission or carbon prices</li> <li>• Market value of wind and solar energy</li> <li>• Profits/losses of generators</li> </ul>



## 2 Model Equations

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This section presents the model equations as they appear in the GAMS code. For a brief syntax introduction, please refer to Section 3.

### 2.1 TOTAL SYSTEM COSTS

Equation (0) is the model's objective function. The model minimizes the total system costs (`COST`) with respect to several decision variables and technical constraints. Total system costs are the sum of investment costs, quasi-fixed capacity costs, variable costs, carbon direct air capture costs, and electricity curtailment costs over all time steps (`t`), regions (`r`), technologies (`alltec`), and vintage classes (`allvin`). Additional costs for ramping and hydrogen imports can arise if these features are used in the scenario.

```
O..
COST =E=

    sum((tec_inv,new,r), INVE(tec_inv,new,r)      * cost_inv(tec_inv))
+ sum((tec_chp,new,r), INVECHP(tec_chp,new,r)    * cost_chp(tec_chp))
+ sum((tec_sto,new,r), INVESTO(tec_sto,new,r)    * cost_energy(tec_sto))
+ sum((r,rr),          NTCINV(r,rr) * km(r,rr) * cost_ntc / 2)

+ sum((alltec,allvin,r), CAPA(alltec,allvin,r) * cost_qfix(alltec))

+ sum((t,tec_supply,allvin,r), SUPPLY(t,tec_supply,allvin,r)
    * cost_var(t,tec_supply,allvin,r))
+ sum((t,tec_demand,allvin,r), DEMAND(t,tec_demand,allvin,r)
    * cost_var(t,tec_demand,allvin,r))

+ sum((t,r), CO2_CAPTURE(t,r) * (1000 - co2(r)))
+ sum((t,r), CURTAIL(t,r)    * cost_curtail);

+ sum((t,tec_thm,allvin,r), GENE_increase(t,tec_thm,allvin,r)
    * cost_ramping(tec_thm,r))$(%RAMPING% = 1)
+ sum(r, H2_IMPORTS(r)      * h2_import_price)$(%H2B% = 1)
```

Investment costs are calculated by the product of power capacity (`INVE`), CHP capacity (`INVECHP`), storage energy capacity (`INVESTO`), and NTC capacity (`NTCINV`) by the specific annualized investment costs (`cost_inv`, `cost_chp`, `cost_energy`, and `cost_ntc`). NTC investment cost also depend on the geographic distance between markets (`km`). The aggregated yearly capacity (`CAPA`), consisting of decommissioned, newly invested, and already existing capacities, is multiplied by the yearly quasi-fixed costs (`cost_qfix`) such as operation and maintenance (O&M) costs. Note that balancing costs for VRE technologies are included in the quasi-fixed costs, such that they are not affecting bids and dispatch. Variable costs are the product of hourly

supply from generators and storage (`SUPPLY`) with specific variable costs (`cost_var`) that include fuel, CO<sub>2</sub>, and variable O&M costs and the product of the hourly electricity demand from dispatchable consumers and storage (`DEMAND`) with the specific variable costs. Note that, for demand, net variable costs are calculated, considering potential revenues, e.g., from the sales of electrolytic hydrogen. The costs for direct air capture and storage of CO<sub>2</sub> are computed as the amount of CO<sub>2</sub> captured (`CO2_CAPTURE`) times specific CO<sub>2</sub> capture price consisting of the fixed cost of 1000 €/t minus the exogenously set ETS CO<sub>2</sub> price (`co2`). Ramping cost depend on the hour-to-hour increase in generation (`GENE_increase`) times ramping cost (`cost_ramping`). EMMA has the option to include a hydrogen balance. Without the hydrogen balance, the hydrogen price is exogenously set and included in the variable cost of supply and demand. With a hydrogen balance, the hydrogen price is endogenously determined and not included in the variable cost of supply and demand, but the costs of hydrogen imports (`H2_IMPORTS`) at a fixed price (`h2_import_price`) are included in the objective function.

## 2.2 ELECTRICITY BALANCE

The electricity balance (`E1`) is the central constraint of the model. The exogenous load (`load_mod`) must be met by the net sum of endogenous supply and demand during every hour and in each region. Note that fixed exports to regions beyond the model scope may be included in the exogenous load parameter. Supply is the sum of generation and storage discharging (`SUPPLY`) and endogenous demand is the sum of consumption technologies and storage charging (`DEMAND`). Furthermore, net exports (`FLOW`) and curtailment (`CURTAIL`) are considered, and the supply variable also includes one technology representing load shedding. The hourly electricity price is defined as the shadow price of the energy balance (unit €/MWh) and the base price is the time-weighted average price over all periods. The model can be interpreted as representing an energy-only market without capacity payments, and the shadow prices can be understood as the market-clearing zonal spot price as being implemented in many deregulated wholesale electricity pool markets. In our case, cost minimization is equivalent to welfare-maximization, and the shadow prices can also be interpreted as the marginal social benefit of electricity. The electricity balance is visualized Figure 1

```
E1(t,r)..
load_mod(t,r) =E= sum((tec_supply,allvin),SUPPLY(t,tec_supply,allvin,r))
               - sum((tec_demand,allvin),DEMAND(t,tec_demand,allvin,r))
               - sum(r,r,FLOW(t,r,r))
               - CURTAIL(t,r);
```

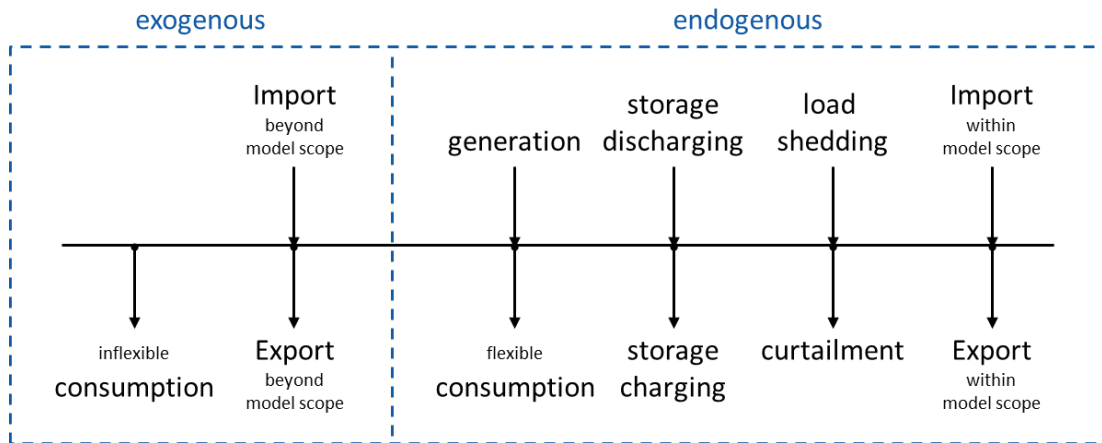


Figure 1: Visualization of the electricity balance

## 2.3 HYDROGEN BALANCE

EMMA features two sets of hydrogen-related technologies: on the electricity supply side hydrogen fired power plants (`tec_h2g = /CCGT_H2, OCGT_H2/`) and on the electricity demand side hydrogen electrolyzers (`tec_h2d = /PTHydrogen/`). The hydrogen prices paid by the former (`h2_price_buy`) represent fuel costs whereas the hydrogen prices received by the latter (`h2_price_sell`) represent revenues.

There are two modes of running the model regarding hydrogen technologies: either with fixed exogenous prices, which are included in the objective function within the variable cost (`cost_var`) or with a hydrogen balance (`E2`), from which hydrogen prices can be derived as endogenous shadow variables. In the latter case, the hydrogen balance is specified on for each region, such that the hydrogen produced by electrolyzes plus regional imports (`H2_IMPORTS`) must be sufficient to supply hydrogen fired unit plus possible an exogenous hydrogen demand for other sectors (`h2_demand_exo`). Note that, when the balance equation is used, the variable costs of hydrogen consuming technologies is assumed to be equal to a mark-up on endogenous hydrogen price to account for the total hydrogen storage and transportation costs.

```
E2(r)..
h2_demand_exo(r) =L=
  H2_IMPORTS(r)
  + sum((tec_h2d,allvin,t), DEMAND(t,tec_h2d,allvin,r)*eff(tec_h2d))
  - sum((tec_h2g,allvin,t),
        SUPPLY(t,tec_h2g,allvin,r)/efficiency(tec_h2g,allvin)
        + GENE_increase(t,tec_h2g,allvin,r)*fuel_ramping(tec_h2g,r)
  );
```

The hydrogen produced is the electricity used by the electrolyzers (`DEMAND`) multiplied by the conversion efficiency (`eff(tec_h2d)`). Analogously, the endogenous hydrogen consumption equals electricity generation (`DEMAND`) divided by the conversion efficiency (`eff(tec_h2d)`).

## 2.4 CARBON BUDGET

Carbon emissions caused by thermal technologies are calculated based on their power output. As for the hydrogen technologies, there are two modes of operation: either with a fixed carbon price or with a constraint on carbon emissions, from which the carbon price can be derived as endogenous shadow variable. Note that carbon prices are usually homogenous across the model regions and the carbon constraint applies to the entire geographical model scope. The carbon constraint is particularly useful when modelling an optimal investment and dispatch for a scenario subject to a specific emission target for the electricity sector. The exogenous emission budget (`co2_cap`) is a country-specific input, to allow for a consistent calculation of the total emission budget when the geographical model scope is changed. The total emissions are calculated as a function of the technology-specific emission factors (`co2_int`), the dispatch variables (`SUPPLY` and `GENE_increase`), the efficiency (`efficiency`), and the additional fuel due to cycling (`fuel_ramping`).

```
E3..
sum(r, co2_cap(r)) =G=
  sum((t,tec_thm,allvin,r),co2_int(tec_thm,r)*(
    SUPPLY(t,tec_thm,allvin,r)/efficiency(tec_thm,allvin)
    + GENE_increase(t,tec_thm,allvin,r)*fuel_ramping(tec_thm,r)
  )
)
- sum((t,r),CO2_CAPTURE(t,r));
```

Note that, when the carbon constraint is activated but not binding, the exogenous carbon price serves as a carbon price floor.

## 2.5 GENERATION CAPACITY CONSTRAINTS

The overall capacity is computed by equation (c), summing up the already existing capacity (`capa0`) and the newly invested capacity (`INVE`) minus the decommissioned capacity (`DECO`). Generation is constrained by available installed capacity. Equations (c1) and (c4) state the capacity constraint for the VRE technologies (`tec_vre`), wind and solar power, and for the technologies with exogenous dispatch (`tec_exo`), bioenergy and run-off-the-river. Equation (c3) and (c4) are the constraints for technologies which supply (`SUPPLY`) or demand (`DEMAND`) electricity. Renewable and exogenous generation is constraint by exogenous generation profiles (`profile`), that captures both the variability of the underlying primary energy source as well as technical non-availability. Availability (`avail`) is the technical availability of dispatchable

```

C(alltec, allvin,r)..
CAPA(alltec,allvin,r) =E=
    sum(                                vin(allvin) , capa0(alltec,vin,r))
    + sum((tec_inv(alltec), new(allvin)), INVE(tec_inv,new,r))
    - sum((tec_inv(alltec), vin(allvin)), DECO(tec_inv,vin,r));

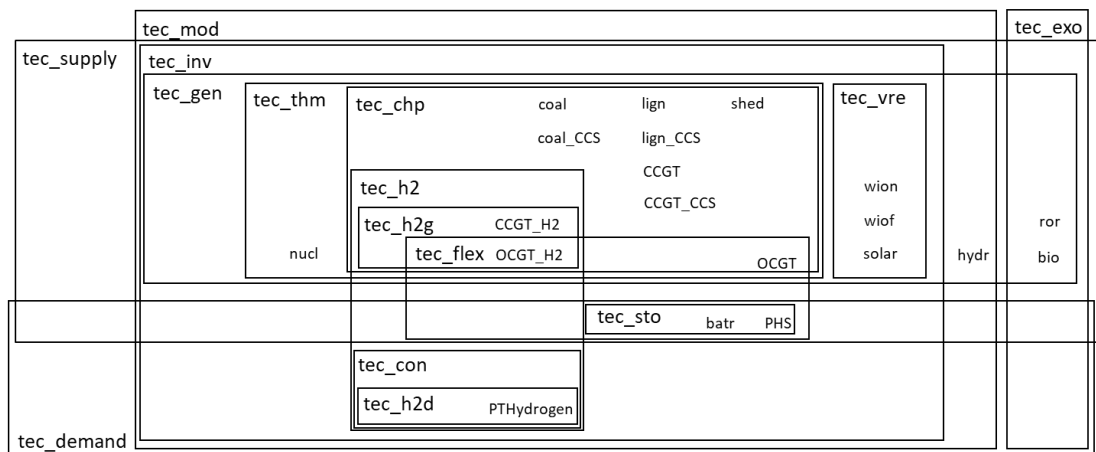
C1(t,tec_vre,allvin,r)..
SUPPLY(t,tec_vre,allvin,r) =E= profile(t,tec_vre,r)*CAPA(tec_vre,allvin,r);

C2(t,tec_thm,allvin,r)..
SUPPLY(t,tec_thm,allvin,r) =L=
    avail(t,tec_thm,r) * (
        CAPA(tec_thm,allvin,r)
        - sum(tec_chp(tec_thm),
            CAPACHP(tec_chp,allvin,r)*(1-CHP_profile(t,tec_chp,"max",r)))
    );

C3(t,tec_con,allvin,r)..
DEMAND(t,tec_con,allvin,r) =L= avail(t,tec_con,r)*CAPA(tec_con,allvin,r);

C4(t,tec_exo,allvin,r)..
SUPPLY(t,tec_exo,allvin,r) =E= profile(t,tec_exo,r)*CAPA(tec_exo,allvin,r);

```



Minimizing equation (0) subject to constraint (E1) and (C2) implies that generators generally produce electricity if the electricity price is equal or higher than their variable costs (exceptions will be discussed in the following). Likewise, minimizing (0) subject to constraint (E1) and (C3) implies that flexible consumers are dispatched only if the electricity price is below their revenues per unit of electricity. As a result, the electricity price equals either the variable costs of

generators that are producing but not at full capacity or the variable revenues of flexible consumers when they are producing but their capacity constraint is not binding. Finally, this formulation implies that if all capacities are endogenous, all technologies earn zero profits, which is the long-term economic equilibrium (for an analytical proof see Hirth and Ueckerdt (2013); for details on price setting and equilibrium investment regarding flexible electrolyzers see Ruhnau (2021)).

## 2.6 POWER SYSTEM INFLEXIBILITIES

One of the aims of this model formulation is, while remaining parsimonious in notation, to include crucial constraints and inflexibilities of the power system, especially those that force generators to produce at prices below their variable costs (must-run constraints). Three types of such constraints are taken into account: CHP generation where heat demand limits flexibility, a must-run requirement for providers of ancillary services, and costs related to ramping, start-up, and shut-down of plants.

### Combined heat and power

One of the major inflexibilities in European power systems is combined heat and power (CHP) generation, where heat and electricity is produced in one integrated process. This configuration can force plants to generate electricity, even if the electricity price is below their variable costs (e.g. when heat demand is high whilst residual load is low). The CHP must-run constraint (K1) guarantees that the electricity generation of each of the five coal- or gas-fired CHP technologies (`tec_chp`) does not fall below a minimum level, derived from the heat demand. This minimum electricity generation is a function of the amount of electric CHP capacity of each technology and vintage (`CAPACHP`), the minimum electricity generation profile (`CHP_profile`), and the technical availability (`avail`). The minimum electricity generation profile is derived from the heat demand profile, considering the design<sup>1</sup> power-to-heat ratios of different CHP types, namely backpressure turbines (BP), extraction-condensing turbines (EC), and exhaust heat recovery (EH), which are weighted by their technology-specific shares in electric capacity. The heat demand profile is based on the When2Heat dataset (see Section 4 for details) and captures the distribution of heat demand over time, relative to the peak demand. The equation (C2) accounts for CHP constraints on the maximum power generation, depending on the amount of CHP capacity of each technology and the maximum electricity generation profile.

---

<sup>1</sup> The operational power-to-heat ratio can be larger than the design power-to-heat ratio for extraction-condensing turbines and exhaust heat recovery.

The maximum electricity generation profile captures the characteristics of the different CHP types: the maximum electricity generation of backpressure turbines is proportional to the heat production, according to the fixed power-to-heat ratio; the maximum power production of extraction-condensing turbines is inversely proportional to the heat production, according to the power-loss coefficient; and exhaust heat recovery has negligible implications for the maximum power output. The operational constraints for backpressure and extraction-condensing turbines as well as a combination of these are illustrated in

Figure 3.

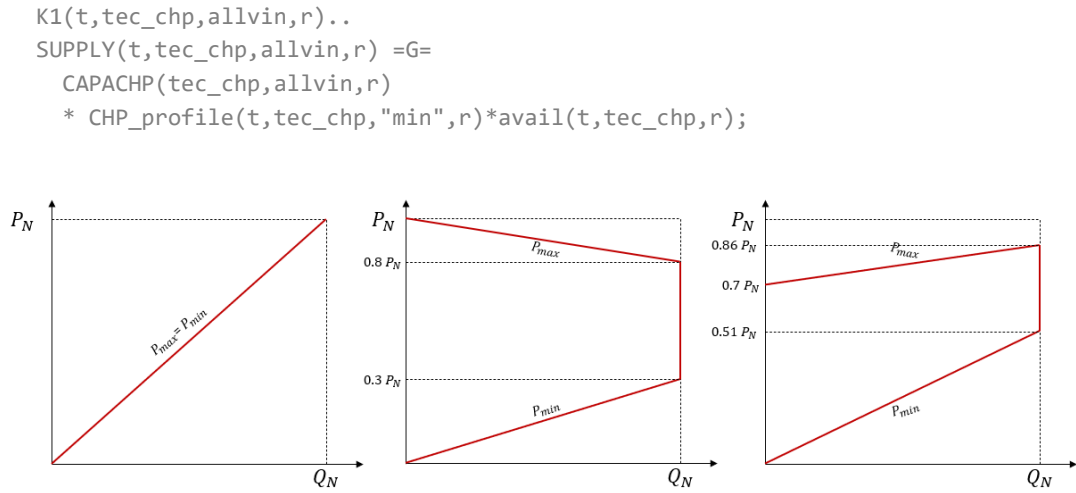


Figure 3: Operational CHP constraints for backpressure turbines (left), extraction condensing turbines (center), and a combination of these (right)

CHP investments ( $INVE_{CHP}$ ) as well as disinvestments ( $DECO_{CHP}$ ) are possible ( $\kappa 3$ ), but the resulting CHP capacity, investments, and disinvestments must be equal or smaller than the corresponding total values for every technology and vintage ( $\kappa 4$  to  $\kappa 5$ ). Furthermore, the current total amount of CHP capacity in each region is not allowed to decrease ( $\kappa 2$ ).

```

K2(r)..
chp_tot(r) =L= sum((tec_chp,allvin),CAPACHP(tec_chp,allvin,r));

K3(tec_chp,allvin,r)..
CAPACHP(tec_chp,allvin,r) =E=
chp0(tec_chp,allvin,r) + sum(new(allvin), INVECHP(tec_chp,new,r))
- sum(vin(allvin), DECOCHP(tec_chp,vin,r));

K4(tec_chp,vin,r)..
DECOCHP(tec_chp,vin,r) =L= sum(tec_inv(tec_chp), DECO(tec_inv,vin,r));

K5(tec_chp,allvin,r)..
CAPACHP(tec_chp,allvin,r) =L= CAPA(tec_chp,allvin,r);

```

## Ancillary services

Electricity systems require a range of measures to ensure stable and secure operations. These measures are called ancillary services. Many ancillary services are traditionally supplied by generators while producing electricity, such as the provision of balancing power or reactive power (voltage support). Thus, a supplier that commits to provide such services over a certain time (traditionally somewhat longer than the delivery periods on the spot market) has to produce electricity even if the spot prices fall below its variable costs. In this model, ancillary service provision is implemented as a must-run constraint on the spinning reserves (A1): an amount (ASC) of dispatchable capacity must be in operation at any time. We set (ASC) to 10% of peak load (as) plus 5% (as\_vre) of VRE capacity of each region (A1), a calibration which is justified in Section 4.

The constraint defines that ancillary services can be provided by thermal power plants except for CHP generators. Furthermore, pumped hydro and hydro reservoirs can provide reserves either while pumping or while generating. Finally, batteries can provide reserves based on their installed power capacity. The shadow price of the ancillary service constraint (A2) is defined as the price for ancillary services, with the unit €/KWh.

```
A1(r)..
ASC(r) =G=
    as(r) + as_vre * sum((alltec(tec_vre), allvin), CAPA(alltec, allvin,r));

A2(t,r)..
ASC(r) =L=
    sum((tec_thm,allvin), SUPPLY(t,tec_thm,allvin,r))
    - as_chp*sum((tec_chp,allvin),
        CAPACHP(tec_chp,allvin,r)*CHP_profile(t,tec_chp,"min",r))
    + sum(allvin,
        SUPPLY(t,"PHS",allvin,r)
        + DEMAND(t,"PHS",allvin,r)
        + SUPPLY(t,"hydr",allvin,r))
    + sum(new, INVE("batr",new,r));
```

## Cycling of thermal power plants

Thermal power plants have limits to their operational flexibility, even if they do not produce goods other than electricity. Restrictions on temperature gradients within boilers, turbines, and fuel gas treatment facilities and laws of thermodynamics imply that increasing or decreasing output (ramping), running at partial load, and shutting down or starting up plants are costly or constraint. In the case of nuclear power plants nuclear reactions related to Xenon-135 set further limits on ramping and down time. These various intertemporal constraints are proxied in the present framework with the addition of the following linearized representation. A first



equation decomposes the power output fluctuation between time  $t-1$  and  $t$  into two positive variables ( $GENE\_increase$ ) and ( $GENE\_decrease$ ). These variables, representing respectively the generation increase and decrease are constrained in a second set of equations ( $Ru$ ) and ( $Rd$ ) to be lower than the technology specific cycling rate (this represents the constraint on cycling activities). Finally, the cost function can be complemented by the term  $C^{cycling}$ , representing the total costs associated with units cycling activities.

```

Ra(t,tec_thm,allvin,r)..
GENE_increase(t,tec_thm,allvin,r) - GENE_decrease(t,tec_thm,allvin,r) =E=
(SUPPLY(t,tec_thm,allvin,r)-SUPPLY(t-1,tec_thm,allvin,r))*1$(ord(t) > 1);

Ru(t,tec_thm,allvin,r)..
GENE_increase(t-1,tec_thm,allvin,r) =L=
rp_constraint(tec_thm,r)*CAPA(tec_thm,allvin,r) + inf$(ord(t) = 1);

Rd(t,tec_thm,allvin,r)..
GENE_decrease(t-1,tec_thm,allvin,r) =L=
rp_constraint(tec_thm,r)*CAPA(tec_thm,allvin,r) + inf$(ord(t) = 1);

```

## 2.7 FLEXIBILITY OPTIONS

The model aims to not only capture the major inflexibilities of existing power technologies, but also to model important flexibility options. Electricity storage, hydro reservoirs, and transmission expansion can make electricity systems more flexible. These options are discussed next.

### Storage

The model includes a set of storage technologies ( $tec\_sto$ ), which differ in terms of cycle efficiency and investment costs. The amount of energy stored at a certain hour ( $SLEVEL$ ) is last hour's amount minus output ( $SUPPLY(tec\_sto)$ ) plus in-feed ( $DEMAND(tec\_sto)$ ) ( $S1$ ), accounting for the storage cycle efficiency ( $eff(tec\_sto)$ ). Both input and output are limited by the power capacity ( $CAPA(tec\_sto)$ ) ( $S2$ ). The amount of stored energy is constrained by the storage energy capacity ( $S3$ ). The only costs related to storage are capital costs in the case of new investments, which we split into a power component and an energy component. In other words, the storage power capacity (the size of the pump/turbine in the case of pumped hydro storage and of the inverter in case of battery storage) are optimized independently of the storage energy capacity (the size of the reservoirs in case of pumped hydro storage and of the battery packs in case of battery storage). The energy-per-power ratio, also referred to as "storage duration", must be at least one hour ( $S4$ ). We are not considering decommissioning of storage.

```

S1(t,tec_sto,allvin,r)..
SLEVEL(t,tec_sto,allvin,r) =E=
    SLEVEL(t-1,tec_sto,allvin,r)
    + sqrt(eff(tec_sto))*sum(tec_demand(tec_sto),DEMAND(t,tec_demand,allvin,r))
    - sum(tec_supply(tec_sto),SUPPLY(t,tec_supply,allvin,r))/sqrt(eff(tec_sto))

S2(t,tec_sto,allvin,r)..
CAPA(tec_sto,allvin,r) =G=
    sum(tec_demand(tec_sto), DEMAND(t,tec_demand,allvin,r))
    + sum(tec_supply(tec_sto), SUPPLY(t,tec_supply,allvin,r));

S3(t,tec_sto,allvin,r)..
SLEVEL(t,tec_sto,allvin,r) =L=
    sto0(tec_sto,allvin,r) + sum(new(allvin), INVESTO(tec_sto,new,r));

S4(tec_sto,new,r)..
INVESTO(tec_sto,new,r) =G= sum(tec_inv(tec_sto), INVE(tec_inv,new,r));

```

## Hydro reservoirs

Hydro reservoirs are modeled as a generation technology subject to special constraints. First, hydro generation (`SUPPLY("hydr")`) depends on an exogenous inflow (`inflow`), which can be stored in a reservoir affecting the reservoir level (`RESERVOIR_V`), and the spillage of water (`SPILL`) (H2). Generation cannot exceed installed capacity (H1) and there may be a required minimum generation (H4). As for storage technologies, the reservoir level is limited (H3). Note that we do not model endogenous investment and decommissioning of hydro reservoirs.

```

H1(t,allvin,r)..
SUPPLY(t,"hydr",allvin,r) =L= CAPA("hydr",allvin,r);

H2(t,r)..
RESERVOIR_V(t,r) =E=
    inflow(t,r) + RESERVOIR_V(t-1,r) - SUPPLY(t,"hydr","1",r) - SPILL(t,r);

H3(t,r)..
RESERVOIR_V(t,r) =L= reservoir(r);

H4(t,allvin, r)..
SUPPLY(t,"hydr",allvin,r) =G= hydro_min(r) * CAPA("hydr",allvin,r);

```

## Interconnectors

Within regions, the model abstracts from grid constraints, applying a copperplate assumption. Between regions, transmission capacity is constrained by net transfer capacities (ATCs). Ignoring transmission losses, the net export (`FLOW`) from `r` to `rr` equals net imports (`-FLOW`) from `rr` to `r` (F1). Equations (F2) and (F3) constraint electricity trade to the sum of existing interconnector capacity (`ntc0`) and new interconnector investments (`NTCINV`) . Equation (F4) ensures lines can be used in both directions. Recall from (o) that interconnector investments have fixed

specific investment costs, which excluded economies of scale as well as non-linear transmission costs due to the nature of meshed HVAC systems. The distance between markets ( $km$ ) is measured between the geographical centers of regions.

```

F1(t,r,rr)..
FLOW(t,r,rr) =E= -FLOW(t,rr,r);

F2(t,r,rr)..
FLOW(t,r,rr) =L= ntc0(r,rr) + NTCINV(r,rr);

F3(t,rr,r)..
FLOW(t,rr,r) =L= ntc0(rr,r) + NTCINV(rr,r);

F4(r,rr)..
NTCINV(r,rr) =E= NTCINV(rr,r);

```

## 2.8 BALANCING COSTS

There are two ways how balancing costs are modelled: costs for reserving spinning reserves, and costs of activation. Spinning reserves are modelled as a reserve requirement as a function of peak load and installed VRE capacity. Activation costs are added as a cost mark-up on generation costs.

## 2.9 ALTERNATIVE PROBLEM FORMULATION

In short, the above cost minimization problem can be equivalently expressed as

$$\min COST$$

with respect to the investment and decommissioning variable `INVE`, `DECO`, `INVECHP`, `DECOCHP`, `INVEST0`, `NTCINV` the dispatch variables `SUPPLY`, `DEMAND`, `GENE_increase` and `GENE_decrease` and the trade variable `FLOW` and `H2_IMPORTS` subject to the constraints. Minimization gives optimal values of the decision variables and the shadow prices and their aggregates.

# 3 Notation

---

This section provides a brief introduction into the GAMS syntax and our naming conventions.

Consider the following example:

```
E(i)..  
VARIABLE(i) * parameter(i) =G= sum(j, another_parameter(j));
```

The declaration of an equation starts with the name of the equation (E) followed by the set(s) of dependent indices in parentheses ((i)) and two dots. In mathematical notation, one would write  $\forall i$ . Subsequently, the equation is presented. Both sides of the equation may depend on the equations' indices. Further indices may be summed up, e.g., `sum(j, a(j))` is the sum of `a(j)` over all indices `j`. There are three types of relation: greater than (`=G=`), equal to (`=E=`) or less than (`=L=`).

For further information on GAMS notation, the reader may refer to the GAMS online documentation.

In addition to the GAMS formalities, we use the convention that parameters are specified in lowercase letters while variables are denoted in UPPERCASE. Parameters are grouped according to their role in the optimization:

- Input parameters carry the prefix `i_`. They are used in calculations prior to the optimizing and to extract data from Excel sheets.
- Model parameters do not carry any prefix. They appear in the equations that constitute the problem.
- Output parameters carry the prefix `o_`. They are used for calculations based on optimal value, e.g., market value of wind energy derived from the electricity price, itself derived from the shadow price of demand.

## 4 Input Data

The input data comprises hourly time series for demand and renewable generation, as well as scalar data on costs, fuel prices, the existing power system, and on yearly demand and generation volumes. Table 4 summarizes key parameters and sources, which are further described below.

Table 4: Key parameters and sources

Topic	Parameter	Source
Time series	Hourly electricity load	Open Power System Data (2019): Data Package Time Series. Version 2019-06-05. <a href="https://doi.org/10.25832/time_series/2019-06-05">https://doi.org/10.25832/time_series/2019-06-05</a>
	Historic hourly electricity generation from wind and solar energy	Open Power System Data (2019): Data Package Time Series. Version 2019-06-05. <a href="https://doi.org/10.25832/time_series/2019-06-05">https://doi.org/10.25832/time_series/2019-06-05</a>
	Future hourly electricity generation from wind and solar energy	ENTSO-e (2020): Mid-term Adequacy Forecast. Pan-European Climate Database. <a href="https://www.entsoe.eu/outlooks/midterm/">https://www.entsoe.eu/outlooks/midterm/</a>
	Hourly heat generation by CHP and heat boilers	EUROSTAT (2021): Supply, transformation and consumption of derived heat (nrg_cb_h). <a href="https://appsso.eurostat.ec.europa.eu/nui/show.do?dataset=nrg_cb_h&amp;lang=en">https://appsso.eurostat.ec.europa.eu/nui/show.do?dataset=nrg_cb_h&amp;lang=en</a>
Costs	Investment and fixed and variable operational costs	Tractebel, Ecofys, E3-Modelling (2018): Technology pathways in decarbonization scenarios. Available at: <a href="https://asset-ec.eu/home/advanced-system-studies/cluster-3/technology-pathways-in-decarbonisation-scenarios/">https://asset-ec.eu/home/advanced-system-studies/cluster-3/technology-pathways-in-decarbonisation-scenarios/</a>
Fuel prices	Gas Prices	International Monetary Fund (2020): Commodity Data Portal. Available at: <a href="https://www.imf.org/en/Research/commodity-prices">https://www.imf.org/en/Research/commodity-prices</a>
	Coal Prices	Quandl (2020): Coal Prices. \$US per Tonne. Northwest Europe Marker Price. Available at: <a href="https://www.quandl.com/data/BP/COAL_PRICES">https://www.quandl.com/data/BP/COAL_PRICES</a>
	Prices of emission certificates under the EU emission trading schemes	ICAP (2020): Allowance Price Explorer. Available at: <a href="https://icapcarbonaction.com/en/ets-prices">https://icapcarbonaction.com/en/ets-prices</a>
Existing power system	National Generation capacity	ENSTOE Power Statistics (2019): Net Generating Capacity. Available at: <a href="https://www.entsoe.eu/data/power-stats/">https://www.entsoe.eu/data/power-stats/</a>
	National CHP capacity	Eurostat (2015): CHP capacity data according type of generation. <a href="https://ec.europa.eu/eurostat/web/energy/data">https://ec.europa.eu/eurostat/web/energy/data</a>

	Unit-level capacities	FRESNA/powerplantmatching at Zenodo (2018) available <a href="https://doi.org/10.5281/zenodo.1403221">https://doi.org/10.5281/zenodo.1403221</a>
	Net transfer capacity	Agency for the Cooperation of Energy Regulators (ACER) (2015-2019): ACER Market Monitoring Report – Electricity. <a href="http://www.acer.europa.eu/Official_documents/Publications/Pages/Publication.aspx">http://www.acer.europa.eu/Official_documents/Publications/Pages/Publication.aspx</a>
Yearly volumes	Yearly electricity demand	IEA (2020): Monthly Electricity Statistics. Available at: <a href="https://www.iea.org/reports/monthly-oecd-electricity-statistics">https://www.iea.org/reports/monthly-oecd-electricity-statistics</a>
	Yearly electricity generation by fuel (for technologies with exogenous dispatch)	ENTSO-E (2019): Power Statistics. Monthly Domestic Values. Available at: <a href="https://www.entsoe.eu/data/power-stats/">https://www.entsoe.eu/data/power-stats/</a>
	Yearly (physical) net electricity exports with non-modeled countries and yearly heat demand	Eurostat (2020): Exports. nrg_te_eh. Available at: <a href="https://ec.europa.eu/eurostat/estat-navtree-portlet-prod/BulkDownloadListing?sort=1&amp;dir=data">https://ec.europa.eu/eurostat/estat-navtree-portlet-prod/BulkDownloadListing?sort=1&amp;dir=data</a>

## Time series

Each region's electricity demand, heat demand, and wind and solar generation are described using hourly information. Time series are available for different weather years with specific temporal and spatial correlation of each parameter as well as between parameters. Load and historic generation data were taken from the Open Power System Data Platform. Future renewable profiles are used from the METIS project. There is the option to scale renewable time series to a specific number of equivalent full load hours within the model.

Regarding the heat demand time series, different types of consumers are distinguished. Industrial heat profiles are assumed to remain constant whereas, heat profiles for residential and commercial sectors are based on the when2heat dataset (Ruhnau et al., 2019). Because the when2heat dataset is for individual buildings and we are interested in district heating, we calculate a rolling average of the hourly profiles to consider the heating grid's inertia. Furthermore, we account for the fact that CHP should operate for at least 5,000 full load hours per year to be economical. Therefore, we cut the peaks of the district heating profiles such that the remaining full load hours just equal 5,000 h/a, assuming that heat boilers supply the peak heating load. Industrial and district heating profiles are aggregated using annual EUROSTAT data.

## Cost parameters

Historic fuel prices are retrieved from the sources given in Table 4. All other cost parameters and the conversion efficiency of new power plants, which affects their variable cost, are taken from De Vita et al. (2018). This report provides cost estimates for different time horizons. Furthermore, this report provides storage cost in €/MWh, which we distinguish into €/MW and

€/MWh assuming a 1:1 ratio and a 10h duration for pumped hydro storage and a 1:2 ratio as well as a 1h duration for batteries. Flexible technologies, including OCGT and storage, are assumed to earn 30% of their investment cost from other markets (e.g., balancing energy). The cost of load shedding is set to 1,000 €/MWh, which can be interpreted as value of lost load. If not stated otherwise, a default discount rate of 5% is used for all investments, including generation, transmission, and storage. Transmission investment costs are 3.4 million Euro per GW NTC capacity and km. Balancing cost are set to 1 €/MWh for wind and 1.5 €/MWh für solar power, which is somewhat higher than reported by Madlener and Ruhnau (2021) for the intraday market only.

### Existing power system

For short- and medium-term model runs, data on the existing power system serve as an input. This includes the existing net transfer capacity and planned network expansion until 2030, which is taken from ACER.

For the existing generation capacity, unit-level data from the Power Plant Matching project (Hofmann et al., 2018) is assigned to different vintage classes based on commissioning dates, and the remaining national generation capacity is equally distributed among vintage classes (Figure 4). For natural gas, we equally distribute the remaining capacity to OCGT and CCGT, with OCGT also including bottom-up data for gas-fired steam turbines (GFST). Brownfield simulations assume a 50-year lifetime of existing power plants to calculate the then-existing capacities.

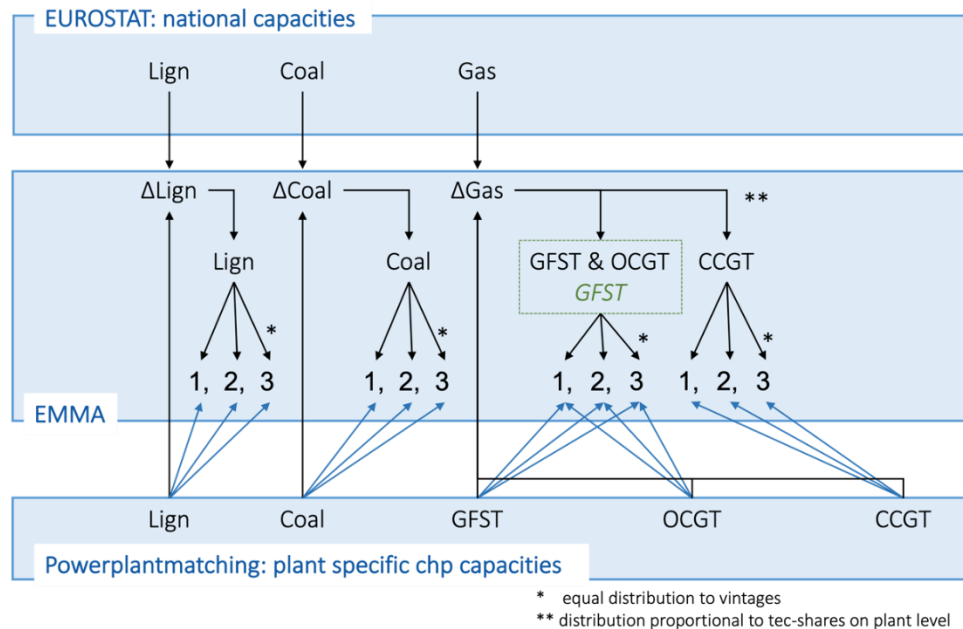


Figure 4: Derivation of existing generation capacity by technology and vintage from unit-level and national data

Similarly, the CHP capacity by technology and vintage is partly based on unit-level data from the Power Plant Matching project (Hofmann et al., 2018) and aggregated into model-specific technologies and vintages. This data is complemented with national CHP capacity data from ENTSO-E (see Table 4). The difference between national generation capacity and the unit-level data from the Power Plant Matching project is distributed among vintages according to the overall electric capacity (Figure 5). Analogously, the difference in CHP steam capacity is distributed to lignite-, coal-, and gas-fired steam turbines. Note that we aggregate GFST with OCGT in our model. Capacities from gas-fired engines are excluded from the EMMA model.

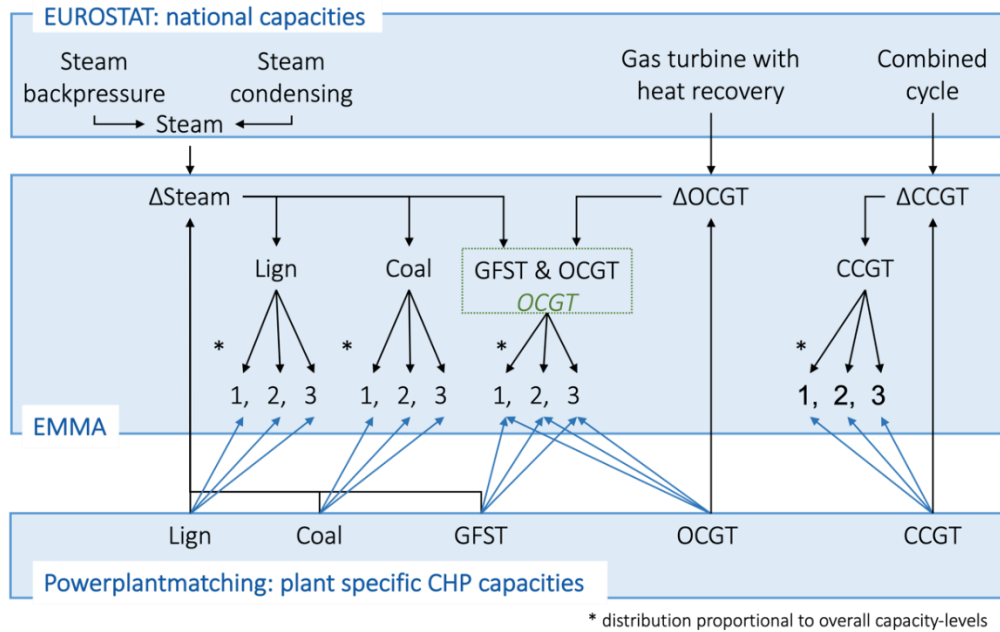


Figure 5: Derivation of existing CHP capacity by technology and vintage from unit-level and national data

### Yearly volumes

Yearly volumes are used to scale demand time series, exogenous generation (bioenergy, hydro run-off-river, and reservoir inflow), as well as for net exports to non-modeled countries.

### Technical availability

There are different options implemented for this parameter. For historic years, an availability time series can be calculated based on ENTSO-E planned and unplanned outage messages and used as an input. For future years, temporally constant and technology-specific availabilities from De Vita et al. (2018) can be used.

### Ancillary services

The parametrization of the must-run due to ancillary services is based on Hirth and Ziegenhagen (2015). Two observations were used to estimate this parameter. First, observed clearing prices can indicate when must-run constraints become binding: equilibrium prices dropping below the variable cost of base load plants for extended periods of time may indicate that



must-run constraints are binding. Nicolosi (2012) reports that German power prices fell below zero at residual loads between 20-30 GW, about 25-40% of peak load. Second, FGH et al. (2012) provide a detailed study on must-run generation caused by system stability requirements, considering network security, short circuit power, voltage support, ramping, and regulating power. They find that the minimum generation requirement reaches 25 GW in Germany, about 32% of peak load. For details on the empirical calibration procedure see (2015).

## 5 Model Limitations

The model is highly stylized and has important limitations when it comes to the representation of detailed technological constraints. An important example includes the absence of demand response beyond load shedding and hydrogen electrolysis, which would further help to integrate VRE generation. Ignoring these flexibility resources leads, e.g., to a downward bias of VRE market values.

Other important limitations to the model include the aggregation of power plants into vintages and, related to this, the absence of unit commitment constraints of power plants such as limits on minimum load, minimum up-time, minimum down-time, ramping and start-up costs, and part-load efficiencies (although the current version of the model includes an approximation of start-up costs at the vintage level); not accounting for market power or other market imperfections; ignoring all externalities of generation and transmission other than carbon; ignoring uncertainty; absence of any exogenous or endogenous technological learning or any other kind of path dependency; not accounting for VRE resource constraints; ignoring grid constraints at the intra-national transmission and distribution level; any effects related to lumpiness or economies of scale of investments.

Table 5, updated from Hirth (2016), summarizes model features and limitations.

Table 5: Model features that are likely to significantly impact the wind market value

Features modeled	Features not modeled
<ul style="list-style-type: none"> <li>• High resolution (hourly granularity)</li> <li>• Long-term adjustment of capacity mix</li> <li>• Realistic (historical/simulated) wind power, solar power, hydro inflow, and load profiles</li> <li>• System service provision</li> <li>• Combined heat and power plants</li> <li>• Hydro reservoirs</li> <li>• Pumped hydro storage</li> <li>• Interconnected power system (imports and exports)</li> <li>• Cost-optimal investment in interconnector capacity</li> <li>• Thermal plant start-up costs</li> <li>• Curtailment of wind and solar power</li> <li>• Carbon prices and/or constraints</li> <li>• Hydrogen balances</li> </ul>	<p><i>Impact likely to be <u>positive</u> for VRE (including these features would change value factor upwards)</i></p> <ul style="list-style-type: none"> <li>• Price-elastic electricity demand, e.g., from industry, electric heating, and electric mobility</li> </ul> <p><i>Impact likely to be <u>negative</u> for VRE (including these features would change value factor downwards)</i></p> <ul style="list-style-type: none"> <li>• Internal transmission constraints/ bidding areas</li> <li>• More detailed modeling of hydro constraints (cascades, icing, environmental restrictions)</li> <li>• Shorter dispatch intervals (15 min)</li> <li>• Market power of non-wind generators</li> <li>• Ramping constraints of thermal plants</li> <li>• Year-to-year variability of wind and hydro capacity factors, and correlation among these</li> <li>• Business cycles / overinvestments</li> <li>• Imperfect foresight</li> </ul>

The impact of the features not modeled (right column) is based on personal assessment.

## 6 Applications

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EMMA is used for national and international research projects on energy market modeling at the Hertie School in Berlin.

### **Model comparison for impact analysis of policy instruments (MODEX-POLINS)**

The project is one of six MODEX model comparison projects founded by the German Federal Ministry for Economic Affairs and Energy. POLINS focuses on policy instruments such as German coal phase out and carbon pricing, which we compare across five models.

Lion Hirth and Oliver Ruhnau lead the project at Hertie School.

### **The Sustainable Energy Transitions Laboratory (SENTINEL)**

SENTINEL is a large research project comprising partners from academia and industry and financed by the European Commission. The project's objective is to improve quality, transparency and policy relevance of energy system modeling and to enhance the possibility of combining different model types. In SENTINEL, we link EMMA with other models and develop new features.

Lion Hirth and Raffaele Sgarlato are the project Hertie's project leads.

### **Publications**

Ruhnau, O., 2022. Why electricity market models yield different results: Carbon pricing in a model-comparison experiment. *Renewable and Sustainable Energy Reviews* 153. <https://doi.org/10.1016/j.rser.2021.111701>

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