Supplementary material

"Can wholesale electricity prices support "subsidy-free" generation investment in Europe?"

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1. Pan-European Electricity Dispatch Model

1.1. Notation

This section gives details about symbols used in our electricity dispatch model. For clarity of presentation, all parameters are capitalised whereas decision variables are written as lowercase and *italicized*. Subscripts are used for indexation while superscripts are used to clarify the meaning of variables and parameters, when these are necessary.

Sets and Indices

$t, tt \in T$	Set of all time periods (in hours) in a modelling horizon T.
$j, jj \in J$	Set of all generators and pump storage units in the model; $j \in J(f)$ – subset of all thermal generation units; $j \in J(s)$ – subset of all hydro pumped storage units.
$n, nn \in N$	Set of all nodes in the model.

Decision Variables

Name	**Description/Comment**	**Unit**
	Continuous Variables	
$p_{j,t}$	Electrical energy generation output of a unit $j \in J(f)$ at time t	MWh
$r^{+}_{j,t}$	Ramp-up capability of a unit $j \in J(f)$ at time t participating in operating reserve (positive/upward) market	MW/hour
$r^{-}_{j,t}$	Ramp-down capability of a unit $j \in J(f)$ at time t participating in operating reserve (negative/downward) market	MW/hour
$d_{j,t}$	Discharge of pump storage unit $j \in J(s)$ at time t	MWh
$c_{j,t}$	Charge of pump storage unit $j \in J(s)$ at time t	MWh
$a_{n,nn,t}$	Flows from node/zone n to the next node/zone nn at time t	MWh
s^{+}_{t}	Load shedding for upward operating reserve requirement at time t	MW/hour
s^{-}_{t}	Load shedding for downward operating reserve requirement at time t	MW/hour
ls^{D}_{t}	Load shedding for electricity demand at time t	MWh
s^{C}_{t}	Electrical energy curtailed at time t	MWh

Exogenous Parameters and Functions

	General	
D_t	Electricity demand at time t	MWh
R^{+}_{t}	Operating reserve requirement (ramp-up requirement) at time t	MW/hour

R_t^-	Operating reserve requirement (ramp-down requirement) at time *t*	MW/hour
$\overline{T_{n,nn}}$	Capacity to transmit electrical energy from zone *n* to zone *nn*	MW
$M_{j,n}$	Matrix (0-1) indicating location of a unit *j* at node *n*	n.a.
$TL_{n,nn}$	Loss factor applied to transmission between zone *n* and the next zone *nn*	%
	Thermal Generation	
HR_j	Heat rate of a generation unit *j*∈*J(f)*	MWh_{th}/MWh_e
RU_j	Maximum ramp-up capacity of a generation unit *j*∈*J(f)*	MW/hour
RD_j	Maximum ramp-down capacity of a generation unit *j*∈*J(f)*	MW/hour
$\underline{P_j}$	Minimum stable generation of a unit *j*∈*J(f)*	MW/hour
$\overline{P_j}$	Maximum electrical energy output of a unit *j*∈*J(f)*	MW/hour
E_J	Carbon intensity of a generator *j*∈*J(f)*	tCO_2/MWh
	Hydro Pumped Storage	
SE_j	Efficiency of charging a storage unit *j* ∈*J(s)*	%
K_j	Maximum charge and discharge capacity of a storage unit *j* ∈*J(s)*	MW/hour
S_j^{INIT}	Initial energy stored at the beginning of a modelling horizon	MWh
$\overline{S_j}$	Maximum storage level	MWh
	Costs	
$C_{j,t}^F$	Fuel cost of a generator *j* ∈*J(f)* at time *t*	£/MWh_{th}
C_t^C	Carbon cost	£/tCO_2
C_j^{VAR}	Variable operating cost of a generator *j*∈*J(f)* and pump storage units *j*∈*J(s)*	£/MWh_e
V_n^D	Value of loss load applied	£/MWh
V_n^{R+}	Cost of loss of spinning up reserve requirement	£/MW/hour
V_n^{R-}	Cost of loss of spinning down reserve requirement	£/MW/hour
C^{CL}	Cost of curtailing electrical energy output	£/MWh

1.2. Equations

1.2.1. Objective function

The objective of this optimization problem is to minimize total power system costs (eq. 1). The optimization assumes a *central planner* who has perfect information about the cost structure of all generation units, the levels of demand and all other technical conditions and as such assumes perfect foresight over the modelling horizon T when searching for optimal economic dispatch of generation units while meeting a set of constraints (eq. 2-13).

$$\min \sum_{n,t} \left(\sum_{j\epsilon J(f)} p_{j,t} \left(\mathrm{C^{F}_{j,t} HR_j} + \mathrm{C_j^{VAR}} + \mathrm{E_j} \mathrm{C}_{\mathrm{t}}^{C} \right) \mathrm{M_{j,n}} + \sum_{j\epsilon J(s)} d_{j,t} \mathrm{C_j^{VAR}} \mathrm{M_{j,n}} + s^{+}_{t,n} V_n^{R+} + s^{-}_{t,n} V_n^{R-} + ls^{D}_{t,n} V_n^{D} + s^{C}_{t,n} \mathrm{C^{CL}} \right) \tag{1}$$

1.2.2. System constraints

First, electricity balance for every period t must be satisfied (eq. 2):

$$\sum_{j\in J(f)} p_{j,t} M_{j,n} + \sum_{j\in J(s)} d_{j,t} M_{j,n} + \sum_{nn} a_{nn,n,t} (1 - \mathrm{TL_{n,nn}}) = \left(D_{t,n} - ls^{D}_{t,n} + s^{C}_{t,n} \right) + \sum_{j\in J(s)} c_{j,t} M_{j,n} + \sum_{nn} a_{n,nn,t} \tag{2}$$

Further, equations 3 and 4 specify requirement for upward and downward operating reserve requirement for each period *t:*

$$\sum_{j\in J(f)} r^{+}_{j,t} M_{j,n} \geq R^{+}_{\mathrm{t,n}} - s^{+}_{t,n} \tag{3}$$

$$\sum_{j\in J(f)} r^{-}_{j,t} M_{j,n} \geq \mathrm{R}^{-}_{\mathrm{t,n}} - s^{-}_{t,n} \tag{4}$$

1.2.3. Thermal generation constraints

The next two constraints are related to ramping up (eq. 5) and ramping down (eq. 6) capability of thermal generation units $j \in J(f)$.

$$p_{j,t} + r^{+}_{j,t} - p_{j,t-1} \leq RU_j \tag{5}$$

$$p_{j,t-1} - p_{j,t} + r^{-}_{j,t} \leq RD_j \tag{6}$$

Constraints 7 and 8 ensures that generating units are operated within allowed range of outputs. Specifically, equation 7 specifies that every generating unit $j \in J(f)$ should produce at least the minimum level accounting for spinning down reserve committed in the reserve market, $r^{-}_{j,t}$. Likewise, equation 8 ensures that power generated by a unit $j \in J(f)$ should be less than the maximum power output given also committed spinning up reserve, $r^{+}_{j,t}$.

$$p_{j,t} \geq r^{-}_{j,t} \tag{7}$$

$$p_{j,t} \leq \overline{P}_j - r^{+}_{j,t} \tag{8}$$

1.2.4. Energy Storage Constraints

Hydro pumped storage facilities are modelled using equations 9-12. Charging (eq. 9) and discharging (eq. 10) cannot exceed capacity limitations while total energy volume stored cannot exceed storage volume capacity (eq. 11). Finally, eq. 12 makes sure that total energy discharging cannot exceed the energy volume that was stored before, S_j^{INIT}, and total net charging during the modelling horizon.

$$c_{j,t} \leq K_j \tag{9}$$

$$d_{j,t} \leq K_j \tag{10}$$

$$\sum_{tt|tt\leq t} (SE_j c_{j,tt} - d_{j,tt}) + S_j^{INIT} \leq \overline{S_j} \tag{11}$$

$$\sum_{tt|tt\leq t} (d_{j,tt} - SE_j c_{j,tt}) \leq S_j^{INIT} \tag{12}$$

1.2.5. Intra-zonal transmission constraints

Finally, transmission flows from one zone *n* to the next zone *nn* are also restricted by the respective transmission capacity (eq. 13).

$$a_{n,nn,t} \leq \overline{T_{n,nn}} \tag{13}$$

2. Modelling procedures

2.1. Rolling horizon

The application of the economic dispatch model to a real-world, highly interconnected, multi-region electricity system may result in a large optimization problem, especially if it is to model every generation unit/plant, perhaps several hundred. Rolling horizon optimisation was implemented for our dispatch model to increase computational performance. A rolling horizon optimisation is one where the overall routine (for a full calendar year model) is reduced to a specified number of sub-problems to avoid excessive solve times or memory issues with the machine used for the optimisation. It assumes that if optimality is achieved in individual simulation runs which form part of a larger model, then overall optimality is achieved for the complete solve window. As a practical matter, the degree of uncertainty about future demand, renewables output and plant availability limit the time horizon over which operational systems optimize.

The approach for transitioning between two modelling periods (e.g., *T1* to *T2*) is to take a snapshot of the system at a time prior to the point of transition: $t_2 = T1 - q_1$, where *T1* is equal to *K*, the number of time intervals within each horizon roll, and q_1 is the selected cut-off time (see Figure 1).

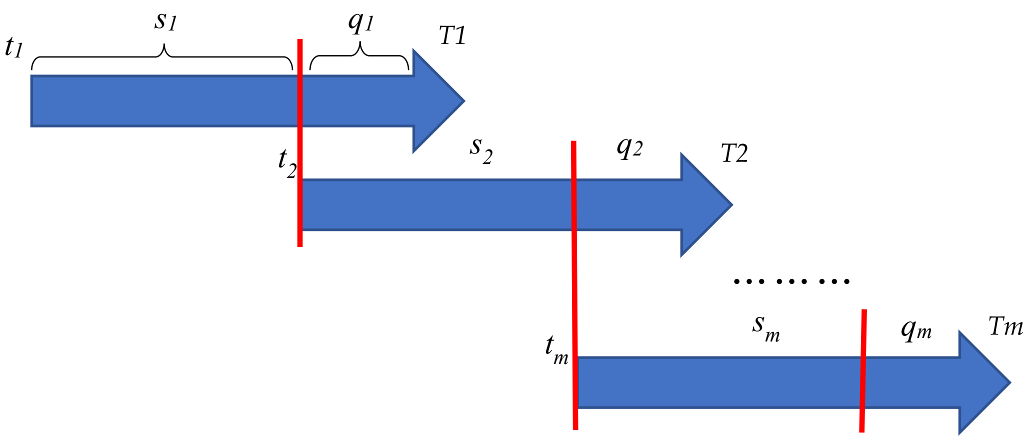

Figure 1: Implementing Rolling Horizon optimization

This snapshot is logged with the dispatch status and generation levels of the various generators. It is also crucial that the energy storage level of storage systems is also recorded. The next optimisation window is then solved from *t2* to $T2 = K$. Note that $s_1 = s_2 = \ldots = s_m = s$ and $q_1 = q_2 = \ldots = q_m = q$, where *m* is number of rolling horizons that will be required to cover the annual modelling horizon (e.g. one year or 8760 hours). Clearly *m* depends on *s* and *q*. For example, if K=100 hours and $q=30$ hours, hence $s=70$ hours then $m=8760/70=126$ rolling horizons that need to be modelled and solved; that is, there will be 126 rolling horizons with 70 hours each and the last 127th horizon will have only 60 hours. However, since q=30 hours, every next rolling horizon the model 'resolves' the previous 30 hours of the preceding horizon. This creates 'redundancy' but this is needed to ensure that solution of each horizon is optimal and would be as close to solving the entire 8760 hours in one go as possible. In this sense, the larger is the *q* the closer to full optimality the combined results of each horizon would be.

The inputs to the second simulation (*T2*) are the commitment and output status of every plant and the energy storage levels. This preserves the state of the system while the demand profile and other exogenous inputs for the new horizon are added. This process is repeated until the full modelling horizon (e.g., one year or 8760 hours) is satisfied.

2.2. Generation expansion and decommissioning

We develop the following heuristic approach for the generation capacity expansion and decommissioning, which searches for a ‘near optimal’ retention, decommissioning and expansion of generation capacity (Figure 2):

1. We first run the electricity dispatch model with a baseline scenario. In this baseline, we can model existing as well new generation capacity;
2. we then calculate operating profit for each plant (eq. 14 and 15) under this baseline;
3. then, we rank all the plants according to their profitability with the most profitable one first to the least profitable last. Based on this profitability ranking, we then calculate cumulative capacity for each market areas (bidding zone modelled) and plot the residual demand curve for a peak demand hour, also considering operating reserve (spinning up) requirement for that peak hour (Figure 3);
4. from step 3, therefore, we have a set of all unprofitable plants. We then remove a set (not all) of most unprofitable plants that lie to the right of the residual demand curve (RD), because they are unprofitable and do not contribute to system security[4];
5. we then run the electricity dispatch model again but without the set of plants that we removed in step 4;
6. and then we calculate profit of all removed plants taking new price projection from step 5 and their generation output from step 1;
7. we then add back those plants that were removed in step 4 if they are profitable under an updated wholesale electricity price projection (prices from step 5) and run the simulation model again (step 1)

Thus, we repeat the above procedure (steps 1-7) until none of the removed plants are profitable under a new price projection or the convergence criteria, the absolute difference in total system operating costs (the value of the objective function, eq.(1)) between two consecutive simulations, is met (e.g., μ=0.1%).

Note that if in step 4 we remove all unprofitable plants that lie to the right of the residual demand curve then the wholesale electricity prices could be very high making some of the removed plants profitable, had they stayed in the market. Thus, to avoid this situation we remove a small portion of unprofitable generation capacity first and check the impact of this on wholesale prices and profitability of all plants (steps 5 and 6). This ‘gradual’ removal of unprofitable plants makes sure that we do not ‘overshoot’ by divesting too many plants and that this will speed up the convergence procedure.

[4] being understood here narrowly as meeting peak hour demand plus spinning up reserve requirement for that peak hour

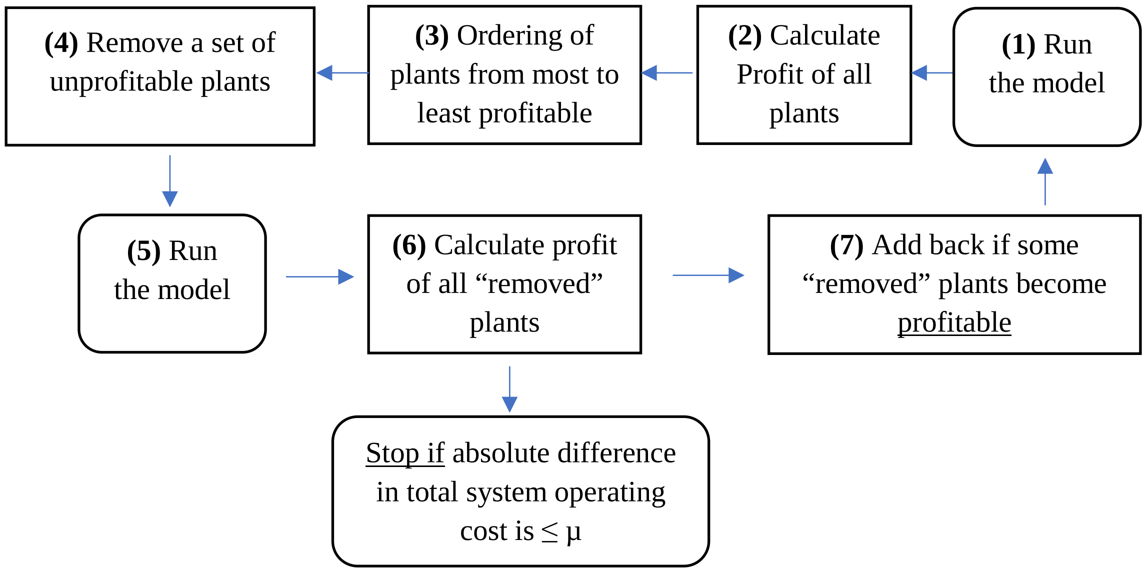

Figure 2: Iterative process for capacity expansion and decommissioning

Note that the above procedure assumes that generation plants receive revenue from the energy-only market, i.e., revenue is based on wholesale electricity prices only. Thus, annual profit, R_j, of a plant j is defined:

$$R_j = \left(\sum_{t=1}^{8760} p^*_{j,t} (\lambda^*_t - \mathrm{C}^{\mathrm{F}}_{\mathrm{j,t}} \mathrm{HR_j} + \mathrm{C}^{\mathrm{VAR}}_{\mathrm{j}} + \mathrm{E_j} \mathrm{C}^{C}_{\mathrm{t}}) \right) - FC_j \tag{14}$$

where * denotes optimal values from the solution to the electricity dispatch model (eq.1-13); p^*_t is optimal dispatch of plant j, λ^*_t is system marginal price (the shadow price of the constraint 2); FC_j is ongoing annual fixed O&M cost (see Table 8); all other parameters and variables are as in the notation section (1.1) above.

In fact, the above procedure is applicable not just to the existing generation capacity that is already in the market but also to new electricity generation capacity. Consider a more generic profit function as follows:

$$R_j = \left(\sum_{t=1}^{8760} p_{j,t} (\lambda^*_t - C_j) \right) - FC_j - AK_j \tag{15}$$

where $p_{j,t}$is expected generation from a conventional plant or from a wind and a solar generation farm, C_j is the variable cost of a generation plant (in case of VRE, $C_j = 0$), AK_j is annuitized overnight capital cost (capex).

Therefore, in step 1 of the above procedure (Figure 2) we can have not just the existing plants but also potentially new plants (both conventional and VRE) as well in the model. The only major difference between the new and existing ones would be the consideration of annuitized capex in the profit function for new plants (eq. 15). Similarly, the difference between the conventional (dispatchable) and VRE (non-dispatchable) plants is the variable cost structure in calculations of their profitability (VRE's instantaneous short-run marginal cost is almost nil).

Taking Germany as an example and following steps 1-3 results in the following Figure 3.

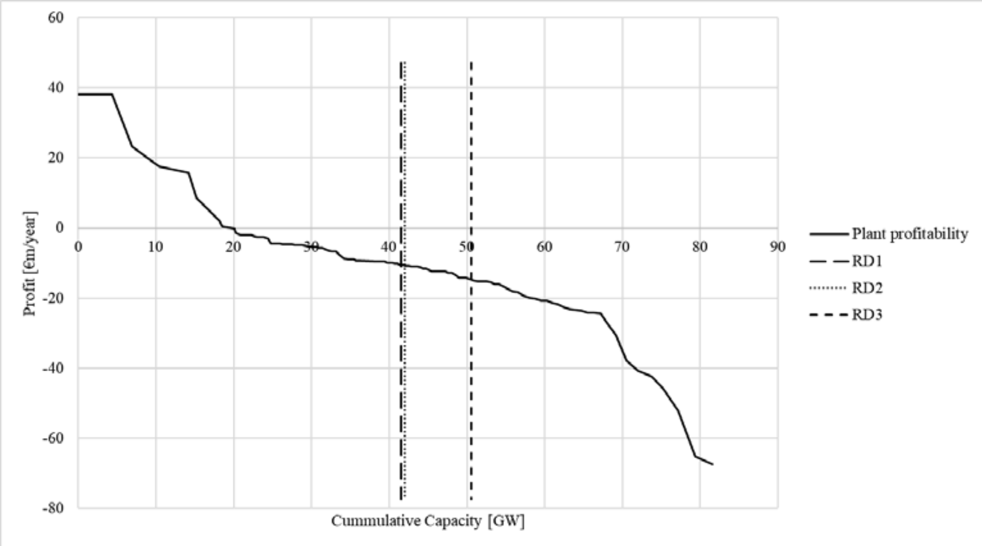

Figure 3: An example of profitability of conventional plants in Germany.
Note: "RD1-3" = residual demand for three peak demand hours.

Figure 3 shows: (1) peak demand hour results in residual demand of 50.6 GWh (with operating reserve margin); (2) total conventional generation capacity is 81.6 GW; (3) the magnitude of the plant level profit ranges from 38m €/year (the most profitable plant) to -70m €/year (the most unprofitable plant); (4) the cumulative profit of all 118 generators who were dispatched at least once in 2025 is: -1345m €/year. Thus, the profitability curve in Figure 3 could be seen as the order of plant decommissioning. One should divest plants that lie to the right of the peak hour residual demand curve ("RD3" in Figure 3), because they are unprofitable and do not contribute to system security.

Figure 4 shows the decommissioning results from 20 simulations. The iterative process (Figure 2) starts with Scenario F in which all unprofitable plants that lie to the right of the peak hour demand were closed (see e.g., Figure 3).

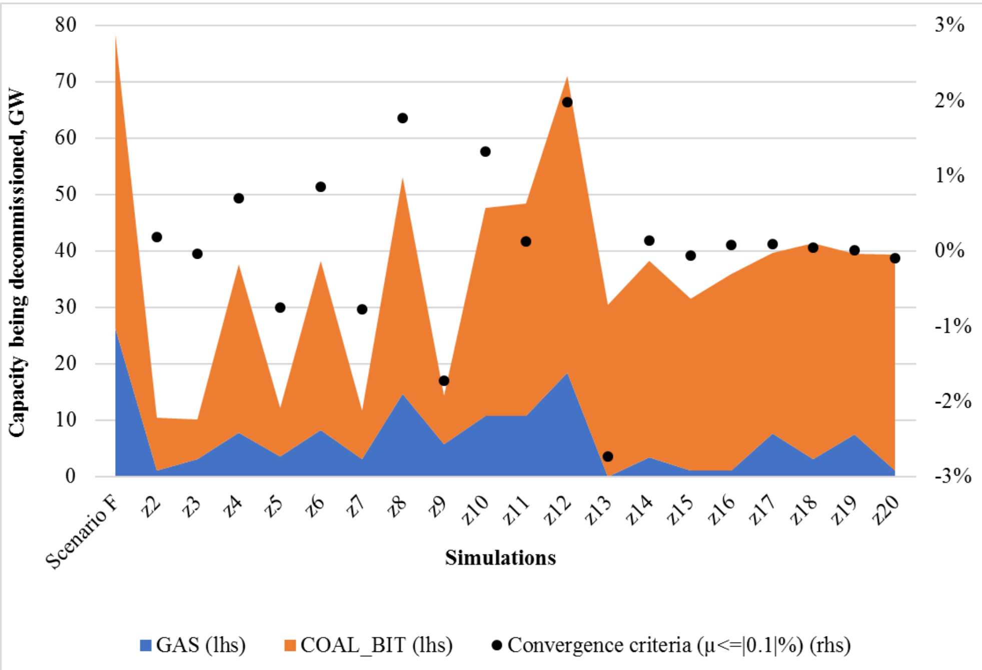

Figure 4: plant decommissioning results based on the heuristic approach.

The procedure then progresses from simulation *z2-z20* and with every iteration it takes out a small portion of unprofitable capacity. One can see that from iteration *z3-z10* the decommissioning capacity oscillate between 10GW and 40 GW primarily driven by large unprofitable coal plants in the GB market; consequently, the convergence criteria also fluctuates between +/-2%. These large coal plants were then removed from the database[5] in simulation *z11* to speed up the convergence and one can see that by iteration *z17* the decommissioning capacity stabilises at 40 GW (or about half of the decommissioned capacity in Scenario F) and the convergence criteria is consistently below the required threshold of |0.1|%.

[5] We should note that all coal plants in the GB market will be closed anyway by 2025.

3. Data input, processing and sources

3.1. Electricity demand and markets in the model

Input data for our modelling is gathered for a number of countries in Europe. Italy, Denmark, Norway and Sweden have electricity markets that are split into zones. These zones are treated as individual market areas in the model, with interconnection to surrounding zones.

Table 1: Market areas in the model

Markets	2015 Demand (TWh)	Raw Load Interval (hours)
1. Austria (AT)	59.2	0.25
2. Belgium (BE)	86.5	0.25
3. Denmark Zone 1 (DK1)	19.8	1
4. Denmark Zone 2 (DK2)	13.0	1
5. Germany (DE)	478.0	0.25
6. France (FR)	470.1	1
7. Italy Centre North (IT-CENTRE-NORTH)	30.7	1
8. Italy Centre South (IT-CENTRE-SOUTH)	46.4	1
9. Italy North (IT-NORTH)	160.0	1
10. Italy Sardinia (IT-SARDINIA)	8.6	1
11. Italy Sicily (IT-SICILY)	17.9	1
12. Italy South (IT-SOUTH)	25.0	1
13. Ireland & Northern Ireland – Single Electricity Market (SEM)	34.5	0.5
14. Netherlands (NL)	97.8	0.25
15. Switzerland (CH)	56.9	1
16. Sweden Zone 1 (SE1)	9.6	1
17. Sweden Zone 2 (SE2)	16.4	1
18. Sweden Zone 3 (SE3)	85.2	1
19. Sweden Zone 4 (SE4)	23.8	1
20. Norway Zone 1 (NO1)	34.9	1
21. Norway Zone 2 (NO2)	34.9	1
22. Norway Zone 3 (NO3)	21.9	1
23. Norway Zone 4 (NO4)	18.7	1
24. Norway Zone 5 (NO5)	18.6	1
25. Great Britain (GB)	299.7	0.5

Source: GB – National Grid; the rest is from ENTSO-E transparency platform

In Italy, there are four additional “city sized” zones: Brindisi, Rossano, Priolo and Foggia. These zones are negligibly small compared to the entirety of Italy’s main zones. As such, they are combined with the zone that geographically encompasses them. Such that Brindisi, Rossano and Foggia are combined with IT-SOUTH and Priolo is combined with IT-SICILY.

For each of the countries of interest, the following data is gathered:

- Average annual hourly load profile
- Average annual hourly capacity factors for each generation technology
- Breakdown of each plant in the region
- Average annual hourly cross-border flows between bidding zones
- Average annual net transfer capacity of flows between bidding zones

Load Profiles

The annual load (electricity demand) for each country was downloaded from the ENTSO-E transparency platform. Depending on the country, the raw data either had hourly, half-hourly or quarter-hourly resolution. The breakdown of each country's annual load resolution is showed in Table 1 ("Raw Load Interval" column).

The raw data downloaded from the ENTSO-E transparency platform contained many instances of missing values (typically 2-3 hours in size). In order to deal with these, the missing values for a particular hour were set to the value from the same hour the year before. If the data is also missing the year before then the day before was used instead.

The aim was to find the average hourly annual load profile, which is the percentage of the demand for each hour of the year with respect to the total demand in MWh for the entire year. As such, the data that is not in hourly resolution must be aggregated. This is done by calculating the average load for consecutive blocks of two data points (half-hourly resolution) and four data points (quarter-hourly resolution). This yields the average hourly demand L_H in MWh. The sum of the average demand for the entire year, L_T, is then calculated, and hence the percentage of each hour, P_H, of the total annual demand is calculated:

$$P_H = \frac{L_H}{L_T} \tag{16}$$

This process was repeated for the years 2015 - 2017. The corresponding load profiles were then averaged in order to reduce the effect of annual fluctuations.

For some countries there was ENTSO-E power statistics load data that went as far back as 2007. These countries were Austria, Belgium, Switzerland, Germany, Denmark, France, Great Britain and the Netherlands. Hence, the timeseries for these countries were extended and averaged out in order to reduce annual fluctuations in load profile as much as possible.

3.2. Generation Data

To calculate the average annual hourly capacity factors for each dispatchable technology, generation and net generating capacity is needed.

Actual electricity generation

The annual generation for each country was downloaded from the ENTSO-E transparency platform. Depending on the country, the raw data either had hourly, half-hourly or quarter-hourly resolution. The breakdown of each country's annual generation resolution is showed in Table 2.

Table 2: Characteristics of annual plant generation data for each zone

Country	Raw Generation Interval (hours)	Number of Years Available
1. AT	0.25	3
2. BE	1	3
3. DK1	1	3
4. DK2	1	3
5. DE	0.25	3
6. FR	1	3
7. IT-CENTRE-NORTH	1	3

8. IT-CENTRE-SOUTH	1	3
9. IT-NORTH	1	3
10. IT-SARDINIA	1	3
11. IT-SICILY	1	3
12. IT-SOUTH	1	3
13. SEM	0.5	1
14. NL	0.25	3
15. CH	1	2
16. SE1	1	1
17. SE2	1	1
18. SE3	1	1
19. SE4	1	1
20. NO1	1	3
21. NO2	1	3
22. NO3	1	3
23. NO4	1	3
24. NO5	1	3
25. GB	0.5	1

The generation data for AT, DE, NL, SEM and GB is aggregated to hourly resolution using the same method as for the load data in the previous section. The data for the majority of countries is averaged over the period 2015 – 2017. For Switzerland, 2016 - 2017 data is used as the first half of 2015 is missing from the ENTSO-E transparency platform, whereas for Sweden, SEM and GB, only 2017 data is used. For this leap years, the 29th of February is omitted from the data, so as to be consistent with non-leap years while averaging.

Swedish Generation Data

In addition, there was no data for generation in each of the zones in Sweden, only for the generation of the country as a whole. There was however data for the capacity of each generation type in each zone. Therefore, to derive the generation of each plant type in the Swedish zones, G_z, the total generation, G_t, for that capacity type was multiplied by the proportion, p_z, of that generation type located in the zone:

$$G_z = p_z G_t \tag{17}$$

For example, if 75% of Sweden's nuclear fleet is located in the zone SE3, then the nuclear generation in SE3 is set to 75% of the total nuclear generation of Sweden. The limitation of this approach is that this calculation results in the same capacity factors for operational plants across each of Sweden's four zones.

SEM Generation Data

There is no generation data for SEM on the ENTSO-E transparency platform, except for peat, pumped storage and hydro run of river. The data for IE is complete, however there is no data from NIE to combine this with as it is mixed with UK. Completed SEM data is created by subtracting GB data from UK data and then combining the result with IE.

Capacity Data

For wind and solar data, the values used for DE, AT, BE, FR, GB, NL, SEM and all IT zones were taken from the Thomson Reuters Eikon portal. The monthly capacity was set to the total installed capacity at the end of each respective month. This takes into account new capacity additions throughout the year. The rest of the installed capacity data was taken from the Open Power System Data Platform[6], which is a composition of statistical data from ENTSO-E, EUROSTAT and respective national regulatory bodies.

Capacity Factors

The annual hourly capacity factors CF for each technology in each country are calculated by dividing the gathered generating data for each hour G_H by the installed capacity for that technology C_T:

$$CF = \frac{G_H}{C_T} \tag{18}$$

Definition of operating reserve

We follow Qadrdan et al. (2014) who suggested that an electricity system with a large share of variable renewable energy (VRE) generation would require spin up reserve equal to 20% of the day-ahead forecasted total wind generation, $WIND_t$, plus the largest conventional generation unit in the system. Thus, for our modelling we define operating reserve requirements (19 and 20) as follows:

$$\mathrm{R}_t^+ = 20\%\ \mathrm{WIND}_t + \max_{j \in J(f)} \overline{\mathrm{P}}_j \tag{19}$$

$$\mathrm{R}_t^- = \frac{\mathrm{R}_t^+}{2} \tag{20}$$

Following Quoilin et al. (2017) we define spin down (eq. 20) reserve as half of spin up reserve.

Plant Database

The plant database is based off data provided by Platts[7].

Remove Non-Dispatchable Technologies

It is only planned to model dispatchable technologies. Therefore, intermittent generation plants such as wind, solar and hydroelectric are omitted from the Platts database.

Aggregating Units

To reduce the size of the dataset being processed, the units making up individual plants were aggregated. This was done by taking all units that are part of the same plant and creating a plant with the same name, and capacity equalling the sum of each of the individual unit. The commissioning date of the plant was taken as the average of the commissioning dates of each of the individual units.

[6] https://open-power-system-data.org/
[7] https://www.spglobal.com/platts/en/products-services/electric-power/world-electric-power-plants-database

Assigning Zones

The Platts data which contains information about specific units for each of the European countries does not differentiate between the internal zones of Italy, Sweden, Norway and Denmark. Thus, the data needs to be separated.

To achieve this splitting, first, for the generating units for which the state in which they are located is known, the zone in which each state lies is determined using google maps. There were 469 plants for which the state was not known, but the city was. For these plants, each individual plant needed to be searched for on google maps and assigned to the relevant zone.

There was a small amount of plants that were not assigned a city or state. In this case the plants were assigned to the primary zone of each country, i.e. the zone with the majority of the country's installed capacity. This missing data for Italy consisted of 25 plants totalling 289.5 MW in capacity, which was assigned to IT-NORTH. For Sweden there was 5 plants missing which made up 20.348 MW which were assigned to SE3. Norway was missing data for 1 plant with 0.23 MW capacity which was assigned to NO1. Finally, for Denmark, there was 48 plants without locational data, making up 40.545 MW of capacity which was allocated to DK1.

Reallocation of Technologies

The Platts data contains many technologies and fuels. A large proportion of these make up a negligible amount of the energy mix, and thus, for simplicity they can be omitted from this dataset. To determine which technologies to omit, the number of plants and total generating capacity for each technology are calculated for each country. The total capacity for that technology is then divided by the total generating capacity for that country. For each technology, this gives the percentage of the generation mix of that country. This percentage mix is shown in the Table 3 below. The "Max %" column shows the maximum percentage mix for that technology in any country. If this is less than 3%, then it is assumed the technology does not make a meaningful contribution to any country and can be omitted. Otherwise, the technology is kept.

Table 3: The maximum portion that each generation technology makes to any of the modelled zones' total generation.

Acronym	Max %	Description
CC	5	Combined-cycle
CCSS	30	Combined-cycle single shaft configuration
CCSS/P	10	Combined-cycle single shaft configuration in CHP (cogen) application
ECE	0	External combustion engine, Stirling or other designs, multifuel
FC	0	Fuel cell
GT	34	Gas/combustion turbine in simple (open) cycle
GT/C	24	Gas turbine in combined-cycle
GT/CP	23	Gas turbine in combined-cycle CHP (cogen) power plant
GT/H	1	Gas turbine with exhaust heat recovery without steam production (cogen - CHP)
GT/R	9	Gas turbine employed for steam-turbine repowering
GT/S	25	Gas turbine with steam sendout or other heat recovery (cogen - CHP)
GT/T	2	Gas turbine in topping configuration with existing conventional boiler and T/G set
IC	3	Internal combustion (reciprocating diesel) engine

IC/CD	0	Internal combustion (reciprocating or diesel) engine in combined-cycle
IC/CP	0	Internal combustion (reciprocating or diesel) engine in combined-cycle CHP (cogen) power plant
IC/H	11	Internal combustion engine with heat recovery (cogen - CHP)
IFGT	0	Indirectly-fired gas turbine, uses heat exchanger and operates as a hot air engine
ORC	0	Organic Rankine-cycle (vapor) turbine or ORC energy converter, also includes some turbo-expanders
RSE	0	Reciprocating steam engine
ST	84	Steam turbine
ST/C	38	Steam turbine in combined-cycle
ST/CD	0	Steam turbine in combined-cycle with gas or diesel engines
ST/CP	9	Steam turbine in combined-cycle CHP (cogen) power plant
ST/D	0	Steam turbine with heat recovery for desalination
ST/S	63	Steam turbine with steam sendout (cogen)
ST/T	3	Steam turbine with heat input from topping gas turbine
TEX	0	Turboexpander, gas expander or pressure recovery turbine
TTG	0	Tidal or wave turbine generator or other hydraulic kinetic energy system

The remaining technologies are then sorted into combined cycle gas turbine (CCGT), combined heat and power (CHP), gas turbine (GT), combustion turbine (CT) and steam turbine (ST) categories as shown in the following Table 4:

Table 4: Reassignment and grouping of generation technologies.

Type in Platts database	**New type in the model**
CC	CCGT
CCSS	CCGT
CCSS/P	CC_CHP
GT	GT
GT/C	CCGT
GT/CP	GT_CHP
GT/R	GT
GT/S	GT
IC/H	CT
ST	ST
ST/C	ST
ST/CP	ST_CHP
ST/S	ST

The same process of technology filtering and allocation is applied to the power plant fuels. The breakdown of maximum fuel percentage of the energy mix of any country is shown in the following Table 5:

Table 5: The maximum portion that each fuel makes to any of the modelled zones' total generation

Acronym	**Max %**	**Description**
BFG	7	Blast-furnace gas also converter gas or LDG or Finex gas (ca. 10% of the heat content of pipeline gas)
BGAS	1	Biogas, produced by anaerobic digestion of biodegradable materials in closed systems
BIOMASS	2	Biomass excluding wood chips but including agricultural waste and energy crops
BL	1	Bioderived liquid fuels such as palm oil or vegetable oils or biodiesel or bio-oil or other bioliquids
COAL	55	Coal
COG	0	Coke oven gas (approximately 50% of the heat content of pipeline natural gas)
COKE	0	Petroleum coke
CSGAS	0	Coal seam gas (aka coal bed gas or coal bed methane or CBM)
CWM	0	Coal-water mixture (aka coal-water slurry)
DGAS	0	Sewage digester gas
GAS	76	Natural gas
GEO	1	Geothermal
H2	0	Hydrogen gas
HZDWST	0	Hazardous waste
INDWST	0	Industrial waste or refinery waste
KERO	1	Kerosene (also see jet fuel)
LGAS	1	Landfill gas
LIGNIN	0	Lignin, a wood polymer
LIQ	2	Pulping liquor (black liquor)
LNG	1	Liquified natural gas
LPG	1	Liquified petroleum gas (usually butane or propane)
MBM	0	Meat and bonemeal
MEDWST	0	Medical waste
MGAS	0	Mine gas (methane from active or abandoned coal mines)
NAP	0	Naphtha
OGAS	2	Gasified crude oil or refinery bottoms or bitumen
OIL	18	Fuel oil
PEAT	5	Peat
PWST	0	Paper mill waste or sludges or wastepaper
REF	9	Refuse (unprocessed municipal solid waste)
REFGAS	0	Syngas from gasified refuse
RGAS	0	Refinery off-gas
RPF	0	Waste paper and/or waste plastic
SHALE	0	Oil shale
TGAS	0	Top gas
TIRES	0	Scrap tires
UNK	3	Unknown
UR	78	Uranium

WOOD	14	Wood or wood-waste fuel
WOODGAS	0	Syngas from gasified wood or biomass
WSTGAS	0	Waste gas or low calorific gas (LCV from refinery or other industrial processes)
WSTH	38	Waste heat
WSTWSL	0	Wastewater sludge

The remaining fuels are then sorted into natural gas, biomass (BIO), coal, oil, waste (WST) and nuclear (NUC) categories as shown in the Table 6 below.

Table 6: Reassignment and grouping of fuels.

Type	**New type**
BFG	GAS
BIOMASS	BIO
COAL	COAL
GAS	GAS
OIL	OIL
PEAT	BIO
REF	WST
REFGAS	WST
UR	NUC
WOOD	BIO
WSTH	WST

Aggregate Technologies

After aggregating individual units into plants, there is still a larger number of small plants in the 0.1 – 100 MW range. In order to reduce the size of the dataset, similar plants within the same zones are aggregated. The criteria for aggregation was that plants with the same fuel, power conversion technology and operating status were combined until the combined plant had a capacity of greater than 300 MW, then a new aggregated plant was created. The commission date of the aggregated plant was set to the average of the commissioning dates of the plants that were combined to make it.

Power plant flexibility parameters

The minimum load at which a plant can operate at consistently has been compiled from multiple sources by Schröder et al. (2013). The average of these values is taken and assigned to each plant in our plant database.
The average start-up time in hours for different technologies has been compiled by Schröder et al. (2013). The start-up factor, which is the fraction of a plant's maximum gross capacity that is added per hour during start-up is calculated by dividing the start-up time into 1. The resulting Table 7 is shown below. It is assumed that the start-up and shut-down factors are the same. If a start-up or shut-down factor is greater than one, it is assigned as 1 to the relevant plant. This is to signify that the plant can start-up within an hour.

Table 7: Power plant flexibility parameters.

	Minimum stable generation	Start-up factor	Ramp up factor
Coal Supercritical	0.360	0.160	2.555
Coal Subcritical	0.380	0.120	1.835
Lignite New	0.375	0.120	1.875
Lignite Old	0.470	0.090	2.250
Gas CC	0.400	0.310	3.440
Gas GT	0.330	5.500	8.180
Gas ST	0.400	0.500	3.900
Oil	0.330	1.000	6.240

Note: minimum stable generation is expressed as a fraction of gross plant capacity; start-up factor is expressed as a fraction of gross plant capacity per hour; ramp up factor is expressed as a fraction of gross plant capacity per hour; CC – combined cycle; GT – gas turbine; ST – steam turbine.

The average ramp gradient in percentage of a plant's total capacity per minute for different technologies has been compiled by Schröder et al. (2013). The ramp factor, which is the fraction of a plant's maximum gross capacity that can be added or taken away per hour is calculated by multiplying the ramp gradient by 60 to convert to hours, and then dividing by 100 to convert from percentage to fraction. The average of all the available values for each technology was then taken. The resulting ramping factor is shown in Table 7. If a ramp factor is greater than one, it is assigned as 1 to the relevant plant. This is to signify that the plant can ramp 100% of its capacity within an hour. It is assumed that ramp-up and ramp-down rates are the same.

Hydro Pumped Storage Plants

It is assumed that hydro pumped storage plant has a charging efficiency of 73%. In addition, it is assumed that they have a maximum operating time of 20 hours and a minimum operating time of 4 hours.

Fixed and Variable Operating and Maintenance Costs

The fixed and variable operating and maintenance (O&M) costs are taken from Schröder et al. (2013). It is assumed that gas turbines and combustion turbines have the same associated costs.

Table 8: Fixed and variable O&M costs.

Fuel	Technology	Variable Cost, €/MWh-e	Fixed Cost, €/kW/yr
Coal	PC Advanced/Supercritical	6	25
Coal	PC Subcritical	6	30
Coal	Lignite - Advanced (BoA)	7	30
Gas	CC	4	20
Gas	CT	3	15
Gas	ST	3	15
Oil	CT	3	6
Oil	ST	3	6

Note: PC – pulverised coal; CC – combined cycle; ST – steam turbine; CT – combustion turbine.

Thermal Efficiency and carbon intensity

The thermal efficiencies for different technologies are compiled by Schröder et al. (2013) and shown in the following table.

Table 9: Power plant thermal efficiency

Fuel	**Technology**	**Thermal efficiency (HHV)**
Coal	PC Advanced/Supercritical	0.463
Coal	PC Subcritical	0.390
Coal	Lignite - Advanced (BoA)	0.443
Gas	CC	0.607
Gas	CT	0.392
Gas	ST	0.412
Oil	CT	0.392
Oil	ST	0.410

These are high heat value efficiencies, and as such must be adjusted to account for non-ideal working conditions. This is done by multiplying the efficiencies by their relative heat value ratios. These are taken from the UK government's official conversion factors[8] and are shown in the following Table 10.

Table 10: Fossil fuel properties

Fuel	**HHV/LHV**
Natural gas	0.90
coal	0.95
Oil (Fuel oil and gas oil)	0.94

The carbon intensity is calculated by dividing the carbon content of the fuel by the plant's thermal efficiency. The carbon intensities of the relative fuels were also taken from the UK government's official conversion factors and are shown in the following Table 11.

Table 11: Carbon intensity of fossil fuels

Fuel	**tCO_2/MW-th**
gas	0.18
coal	0.31
Oil	0.25

3.3. Interconnector Flows and Net Transfer Capacities between bidding zones

[8] https://www.gov.uk/government/publications/greenhouse-gas-reporting-conversion-factors-2016

Interconnector flows with bidding zones outside the scope of the model

Day ahead hourly cross-border interconnector flows for 2015 – 2017 are downloaded from the ENTSO-E transparency platform. This data is averaged out to get the average hourly interconnector flows from/to zones outside the scope of the current modelling version. The flow between countries of interest and countries outside the system (Germany and Poland, for example) are combined to get the net flow in/out of each of the countries.

Net transfer capacities between bidding zones in the model

The annual hourly physical cross-border flow from 2015 until July 2018 between each bidding zone which we model was downloaded from the ENTSO-E transparency platform. This is followed by the hourly day ahead minimum transmission capacity for the same time period. For the transfer capacity there was no data for inter-zone connections (such as Italian bidding zones), only connections between whole countries. The net transfer capacity for each border was estimated by taking the cross border physical flows and minimum net transfer capacities for Aug 2017-Jul 2018, and assuming the maximum value at any point in this year is the net transfer capacity of the connection.

Further we model all interconnector projects between GB and neighbouring markets (Table 12) that got either cap and floor regime or exemption from the Third Energy Package by GB and other European energy regulatory authorities.

Table 12: Expected interconnection between GB and other markets

Project Name	Developers	Connecting Country	Capacity	Cap and Floor Regime	Exemption	Estimated Delivery Date
ElecLink	Star Capital Partners Limited and Groupe Eurotunnel	France	1000MW	No	Yes (Third Package)	2019
NEMO	NGIH and Elia	Belgium	1000MW	Yes	No	2019
NSN	NGIH and Statnett	Norway	1400MW	Yes	No	2020
FAB Link	Transmission Investment and RTE	France	1400MW	Yes	No	2022
IFA2	NGIH and RTE	France	1000MW	Yes	No	2020
Viking	NGIH and Energinet.dk	Denmark	1400MW	Yes	No	2022
Greenlink	Element Power	Ireland	500MW	Yes	No	2021

Source: Ofgem (https://www.ofgem.gov.uk/electricity/transmission-networks/electricity-interconnectors)

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