Price-setting tipping points in decarbonising EU electricity markets: Supplementary Material

Ignacio Martínez[1], Derck Koolen[1,2], Massimo Tognoni[1], Sebastian Sterl[1,3*]

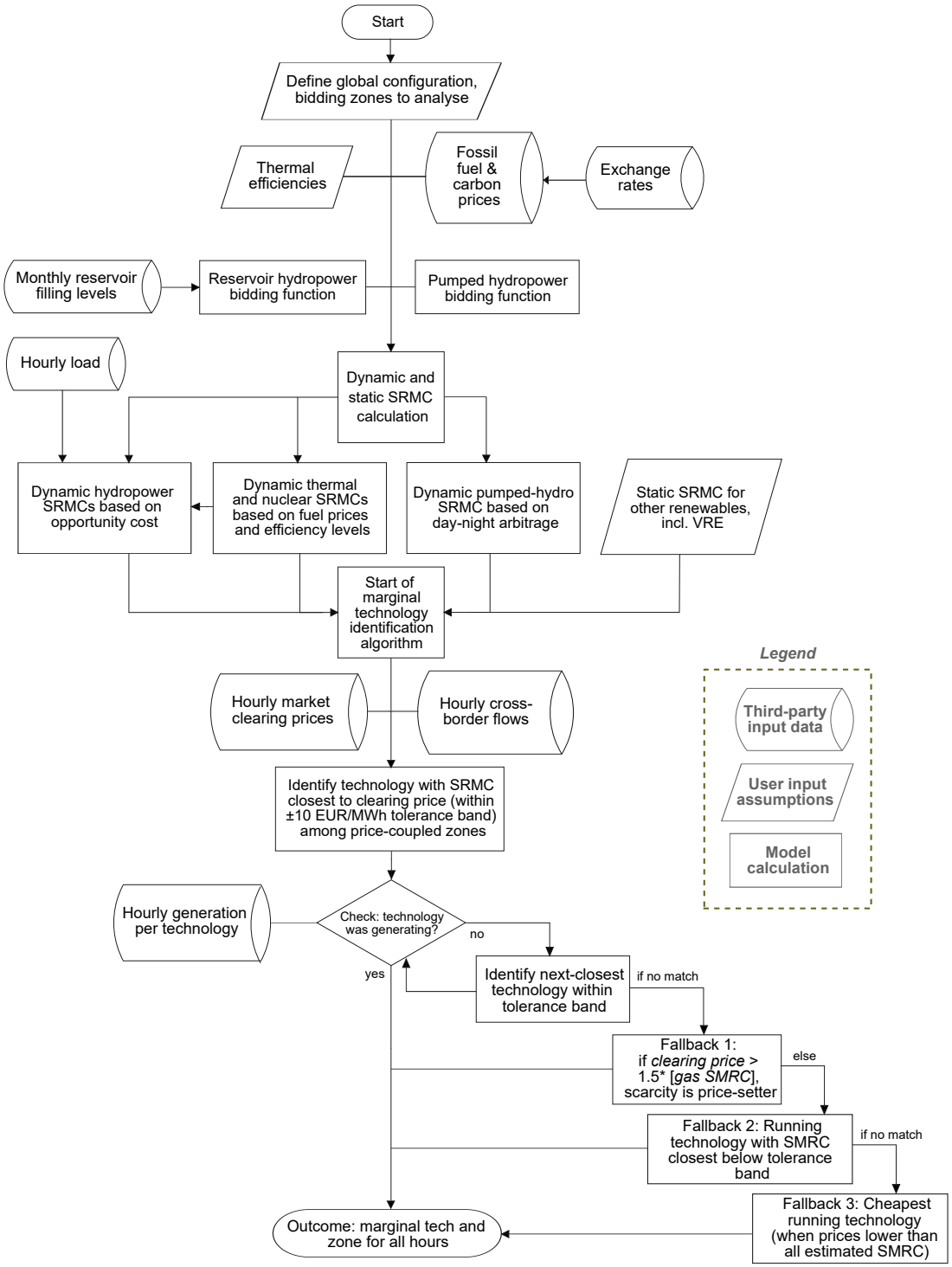
[1] Directorate-General for Energy, European Commission, Brussels, Belgium
[2] School of Economics, Utrecht University, Utrecht, The Netherlands
[3] Department of Water and Climate, Faculty of Engineering, Vrije Universiteit Brussel, Brussels, Belgium
[*] Corresponding author, email: sebastian.sterl@vub.be

Contents

Supplementary Note 1 Price-setting algorithm diagram 2
Supplementary Note 2 Hourly price-setting trends 3
Supplementary Note 3 Cross-border price-setting heatmap 5
Supplementary Note 4 Tabulated parameter values for SRMC calculation 7
Supplementary Note 5 Hydropower SRMC calculation 9
Supplementary Note 5.1 Reservoir hydropower 9
Supplementary Note 5.2 Pumped hydro storage 11
Supplementary Note 6 Sensitivity analysis 12

Supplementary Note 1 Price-setting algorithm diagram

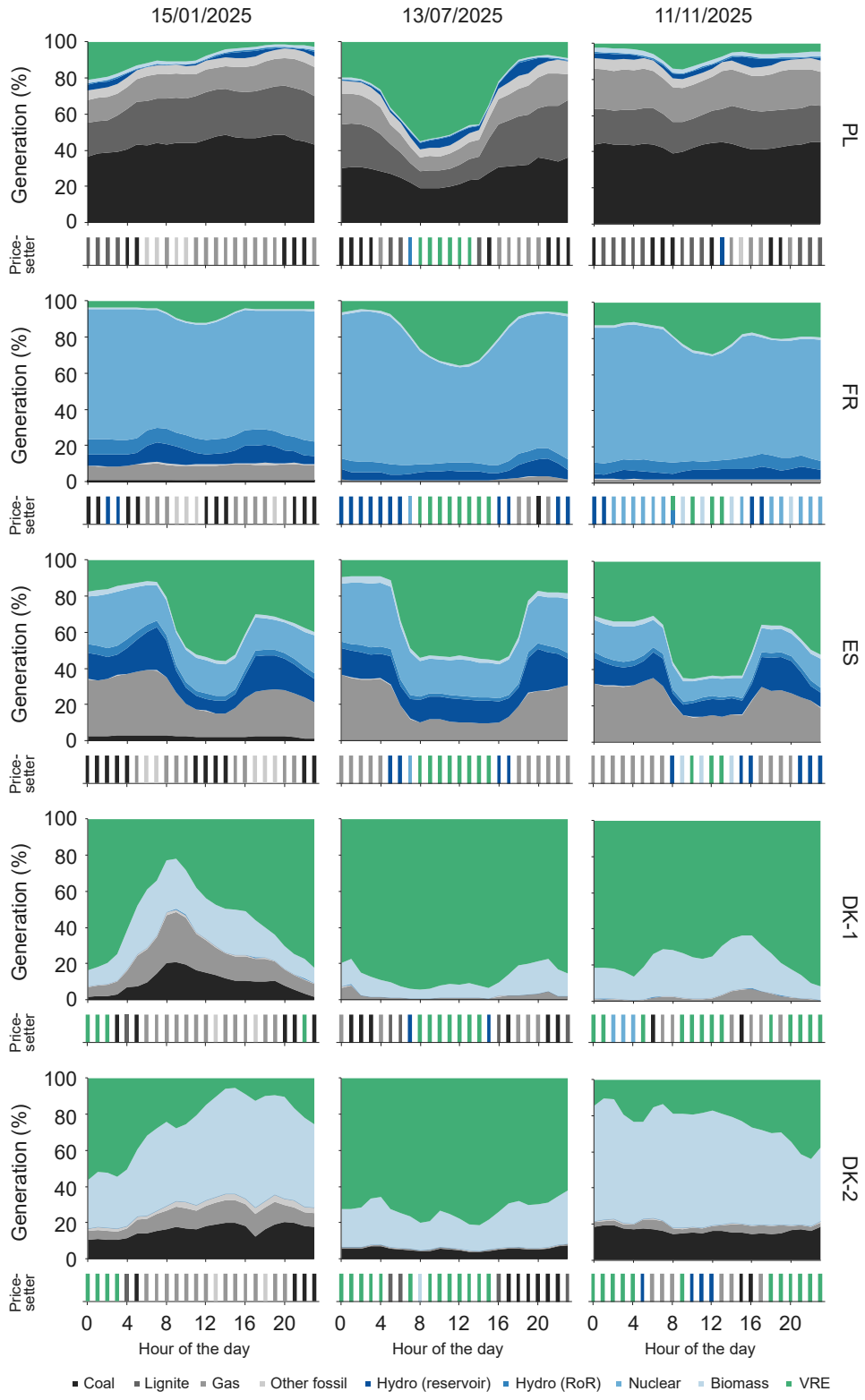
In Supplementary Figure 1, we show a schematic diagram of the logic of the price-setting identifying algorithm, as described in Methods.



Supplementary Figure 1: A stepwise overview of the algorithm of the price-setting analysis.

Supplementary Note 2 Hourly price-setting trends

In Figure 2, we show the daily generation and price-setting dynamics for individual days and zones for the same regions shown in Figure 3c of the paper (PL, FR, ES, DK-1, DK-2).



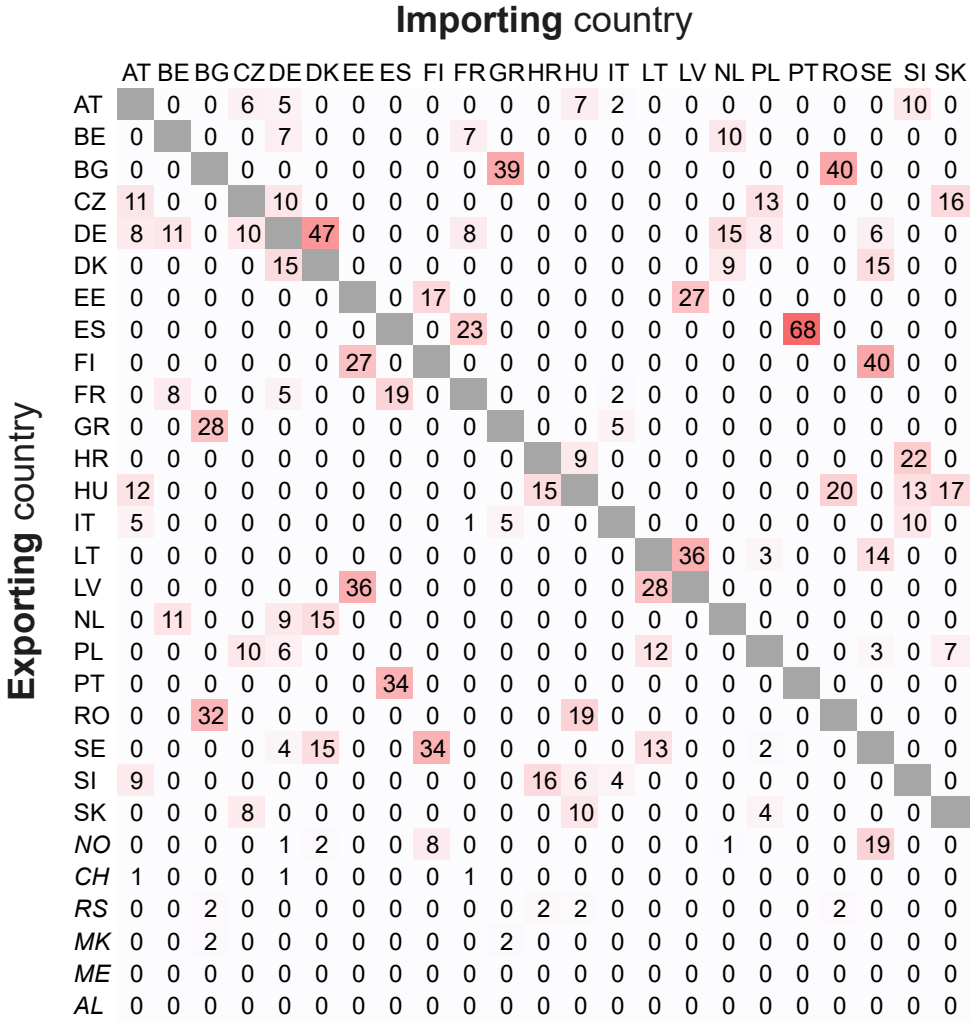
Supplementary Figure 2: Example daily generation and price-setting dynamics for PL, FR, ES, DK-1 and DK-2 (in rows) for three example days (in columns) of the year 2025.

The price-setting time series is here binary (yes/no per technology and hour), the only exception being hours with co-marginal technologies (see Methods); here, the only such occurrence is in FR at 8h on 11/11/2025 (hydro run-of-river and VRE co-marginal). For instances where the price-setting technology appears absent from the generation graph, this is either because (i) the generation level of the marginal technology was nonzero but very small and therefore not visible in the plot, as for "other fossil fuels" from 17-19h on 15/01/2025 in ES, or (ii) the price-setter was located in another bidding zone, as for reservoir hydropower at 5h and from 10h-13h on 11/11/2025 in DK-2.

Supplementary Note 3 Cross-border price-setting heatmap

The heatmap in Supplementary Figure 3 shows details on the cross-border price-setting presented in Figure 4 of the paper (pertaining to the year 2025). The interpretation of the graph is as follows: countries on the horizontal axis (importing countries) have their prices set by neighbours for the percentages of time indicated in the columns, with the respective responsible countries on the vertical axis (exporting countries, including non-EU). For example, Portugal (PT) was importing prices from Spain (ES) for 68% of the time (the technological breakdown is given in Figure 4 of the paper).

For countries with more than one neighbour from which they can be simultaneously importing (unlike Portugal, which only borders Spain), the numbers in the columns could sum up to more than the total share shown in Figure 4 of the paper. This is because technologies from different exporting countries could be classified as "co-marginal" (when more than two zones are "price-coupled") in the end result; they appear in the heatmap below, but are not double-counted in Figure 4 of the paper.



Supplementary Figure 3: Heatmap indicating the percentage of time in which countries on the horizontal axis (importing) were having their electricity prices set by countries on the vertical axis (exporting); cf. Figure 4 of the paper. Note: DE (Germany) here includes Luxembourg, as part of the same bidding zone. Countries are abbreviated by their alpha-2 ISO codes[1].

The main non-EU countries identified as price-exporter are Norway, Serbia, and Switzerland, with minimal contributions by North Macedonia, Montenegro, and Albania. In reality, other non-EU countries are likely have been price-exporters too in certain moments, notably the United Kingdom

(to France), Bosnia and Herzegovina (to Croatia), Turkey (to Greece and Bulgaria), and Morocco (to Spain). However, none of these report sufficient data to the ENTSO-E Transparency Platform to allow completing the required iterations of the algorithm to identify them as price-setters in EU bidding zones. The United Kingdom stopped reporting post-Brexit, Bosnia and Herzegovina report production but not prices, Turkey report neither so far, and Morocco have never been associated with the transparency platform.

Supplementary Note 4 Tabulated parameter values for SRMC calculation

This section provides tabulated values used as input for the SRMC calculation for different technologies (aside from reservoir and pumped-storage hydropower, explained in Supplementary Note 5).

Supplementary Table 1 lists the main parameters used for each thermal technology: fuel calorific value (CV), fuel price, carbon intensity, and variable operation and maintenance (VOM) cost. Supplementary Table 2 shows used fuel prices for commodities for countries where those could not be obtained from market sources. Note that we did not consider country-specific taxes for e.g. nuclear fuels and the like. Supplementary Table 3 shows added transport costs in addition to the TTF price, for countries without data from market sources. Assumptions on country-level efficiency ranges of thermal power plants are provided alongside the code and data (see "Code availability" in the paper). We note that biomass generation additionally reflects a subsidy of 60 EUR/MWh (informed by CEER [2] values), resulting in approximately 15 EUR/MWh of effective market bid (SRMC minus the subsidy) in our algorithm. Supplementary Table 4 mentions additional parameters specific to nuclear generation. Supplementary Table 5 shows the static Short-Run Marginal Costs ranges that were used for technologies other than thermal (including nuclear) and reservoir hydropower. Here, marginal costs for VRE can be nonzero despite the lack of fuel costs[3], for instance reflecting wear and tear (e.g. per every rotation of a wind turbine) as well as insurance premiums to protect against deviating from scheduled production due to potential inaccuracies in meteorological forecasts.

Supplementary Table 1: Core thermal parameters used in the SRMC calculation.

Technology	Fuel CV	Unit	CO_2 factor (tCO_2/MWh_{th})	VOM (EUR/MWh_{el})
Gas	48.0	GJ/tonne	0.202	2.0
Coal (hard)	25.0	GJ/tonne	0.341	3.0
Lignite	11.9	GJ/tonne	0.364	3.0
Oil shale	9.0	GJ/tonne	0.385	3.0
Oil	40.4	GJ/tonne	0.279	2.0
Biomass	15.6	GJ/tonne	0.000	6.0
CHP (gas)	48.0	GJ/tonne	0.202	2.0
Nuclear	–	–	0.000	6.0

Note: "Oil shale" and "Oil (heavy)" are counted under "other fossil fuels" in the figures of this paper and its supplements. The study used fuel calorific values and emission factors from IPCC (2006)[4] in alignment with respective market sources[5][6]. Variable Operation and Maintenance costs were informed by the EU Reference Scenario 2020 technology assumptions (European Commission, 2021)[7].

Supplementary Table 2: Fuel and input prices set directly.

Technology	Price (EUR/MWh_{th})	Source
Lignite	6.00	based on ERAA 2025
Oil shale	8.77	based on ERAA 2025
Biomass	23.80	based on Fraunhofer 2024
Nuclear	5.00	based on ERAA 2025

Note: For simplicity and in the absence of a single EU-wide reference value, this study broadly used input from ERAA (2025)[8] and Fraunhofer (2024)[9] in case market-based sources were unavailable.

Supplementary Table 3: Assumed gas transport costs over TTF Base Price

Country Code	**Country Name**	**Transport Cost (€/MWh)**
EE	Estonia	2.0
LV	Latvia	2.0
LT	Lithuania	2.0
PL	Poland	1.5
CZ	Czechia	1.0
SK	Slovakia	1.5
HU	Hungary	2.0
RO	Romania	3.0
BG	Bulgaria	3.5
GR	Greece	2.5
SI	Slovenia	1.0
HR	Croatia	2.0

Note: Country-level transport costs were informed by transport costs included in market monitoring reports published by ACER[10].

Supplementary Table 4: Efficiencies nuclear technology

Parameter	Value
Efficiency (min)	0.320
Efficiency (max)	0.345

Note: Nuclear net efficiency were informed by the ratio of net electrical to thermal capacity values published by IAEA (2026)[11].

Supplementary Table 5: SRMC values used in the run of the algorithm presented here.

Technology	Min (EUR/MWh)	Max (EUR/MWh)
Hydro run-of-river	10	20
Waste	5	18
VRE: Offshore wind	10	20
VRE: Onshore wind	0	15
VRE: Solar	0	15

Note: "Waste" is counted under "biomass" in the figures of this paper and its supplements.

Supplementary Note 5 Hydropower SRMC calculation

This section explains the details of the logic behind the calculation of the SRMC for hydropower. Supplementary Note 5.1 deals with reservoir hydropower, while Supplementary Note 5.2 deals with pumped-storage hydropower (both counted under "reservoir hydropower" in the graphs in the main paper).

Supplementary Note 5.1 Reservoir hydropower

The reservoir hydropower representation in the model is implemented in several steps, inspired by previous literature on the dependency of strategic bidding by hydropower plants in the context of the opportunity cost, affected by water scarcity, demand, and other price-setters [12,13].

Step 1: Main variables: gas ceiling, reservoir scarcity factor and demand factor
a) The gas ceiling $C_{\text{gas}}(t)$ establishes the absolute upper limit on reservoir hydro's opportunity cost: reservoir hydro is never allowed to bid above a fixed share of the prevailing gas price. It is defined as

$$C_{\text{gas}}(t) = SRMC_{\text{gas}}(t) \cdot \gamma \tag{S1}$$

where $\gamma = 0.85$ is the modeller's choice for a gas ceiling factor, capping the reservoir hydro's opportunity cost at 85% of the gas SRMC.

b) The filling reservoir level is then used to calculate a scarcity measure. This translates into zero scarcity when reservoirs are at maximum levels and maximum scarcity when reservoirs are at minimum levels. We define the scarcity factor $\sigma(t)$:

$$\sigma(t) = 1 - \ell(t), \tag{S2}$$

where $\ell(t) \in [0, 100\%]$ is the reservoir filling level (%) at time t obtained from the ENTSO-E weekly reservoir data forward filled to hourly resolution. For zones without own reservoir reporting in the ENTSO-E Transparency Platform, the reservoir levels of a neighbouring hydro system are used as a proxy (for example, Austrian levels are used for Germany and for Czechia). If $\ell(t)$ is unavailable for certain periods, it is interpolated from adjacent weekly observations (forward and backward filling, with the series median as last-resort fallback).

c) The demand factor $d(t)$ measures the load remaining after non-dispatchable generation. It represents the system tightness at a given hour,

$$d(t) = \min\left[1,\ \frac{RD(t)}{RD^{\max}}\right], \tag{S3}$$

where $RD(t)$ is hourly residual demand (load in the system, minus solar, wind and run-of-river generation, floored at zero) and $RD^{\max}$ its maximum in the zone over the sample period.

Step 2: Base bid
The bid rises linearly with the scarcity factor of water reservoir, expressed as a share of the gas ceiling. It is defined as

$$SRMC_{\text{res}}^{\text{base}}(t) = C_{\text{gas}}(t)\big[\phi_{\text{full}} + \sigma(t)\,(\phi_{\text{empty}} - \phi_{\text{full}})\big], \tag{S4}$$

with $\phi_{\text{full}} = 0.25$ and $\phi_{\text{empty}} = 0.85$ determining the width of the hydropower bidding range. A hydropower plant with full reservoir ($\sigma(t) \to 0$) bids conservatively, closer to the lower bound of bids

$\phi_{\text{full}} \cdot C_{\text{gas}}$, while a plant with a nearly empty reservoir ($\sigma(t) \to 1$) bids more aggressively, closer to the gas ceiling at $\phi_{\text{empty}} \cdot C_{\text{gas}}$, reflecting the higher opportunity cost of releasing scarce water.

Step 3: Demand adjustment
The base SRMC is then corrected for with respect to residual demand. This aims at reflecting incentives to bid higher when the power system is under stress (i.e. when it needs generation to cover the residual demand). In hours where residual demand is high, the reservoir's hydropower bid will move towards the upper ceiling, reflecting the value of stored water at that time. The adjustment factor $\Delta_{\text{demand}}(t)$, is proportional to the gap between the current bid and the gas ceiling.

$$\Delta_{\text{demand}}(t) = w_d \, d(t) \left(C_{\text{gas}}(t) - SRMC_{\text{res}}^{\text{base}}(t)\right), \tag{S5}$$

$$SRMC_{\text{res}}^{\text{adj}}(t) = SRMC_{\text{res}}^{\text{base}}(t) + \Delta_{\text{demand}}(t), \tag{S6}$$

where $w_d = 0.5$ is the demand weight assigned to this factor, and $d(t)$ is the demand factor. The proportionality coefficient, raises with system tightness. For example, where demand factor is at the lowest ($d = 0$) the bid is unchanged. However, when the demand factor is at historical peak, ($d = 1$) it rises by half of the distance to the ceiling. The adjusted bid the approached the gas cieling but it neaver reaches it, because $w_d \, d(t) \leq 0.5$. Also, as $d(t) \geq 0$, the adjustment does not lowers the bid.

Step 4: Global range
Then, the adjusted bid SRMC is capped into an assumed allowable range which hydropower bids are assumed to not surpass. Thus, the bid is kept within the modeller's defined global range $[L, H] = [0, 100]$ EUR/MWh.

$$SRMC_{\text{res}}^{\text{adj}}(t) \leftarrow \max\left[L,\ \min\left[H,\ SRMC_{\text{res}}^{\text{adj}}(t)\right]\right], \tag{S7}$$

where $L = 0$ and $H = 100$ EUR/MWh denote the floor and ceiling of the SRMC.

Step 5: Construction of the min/max range
The function then expresses reservoir hydro's SRMC as a band around the adjusted value, representing a level of bidding flexibility buffer $B = 8$ EUR/MWh,

$$SRMC_{\text{res}}^{\min}(t) = \max\left[L,\ SRMC_{\text{res}}^{\text{adj}}(t) - B\right], \qquad SRMC_{\text{res}}^{\max}(t) = \min\left[H,\ SRMC_{\text{res}}^{\text{adj}}(t) + B\right], \tag{S8}$$

The upper bound is additionally capped at the gas ceiling:

$$SRMC_{\text{res}}^{\max}(t) \leftarrow \min\left[SRMC_{\text{res}}^{\max}(t),\ C_{\text{gas}}(t)\right] \tag{S9}$$

Note that only the upper bound is re-capped against the gas ceiling; the lower bound is not adjusted at this stage.

Step 6: Minimum spread
In case the capping in Step 5 narrows the band below 8 EUR/MWh, the band is recentred around its midpoint $m(t)$, restoring the spread: $[\max(L, m(t) - B/2),\ \min(H, m(t) + B/2)]$, ensuring the bidding range is not narrower than the minimum spread ($B = 8$ EUR/MWh).

The function returns $\left(SRMC_{\text{res}}^{\min}(t),\ SRMC_{\text{res}}^{\max}(t)\right)$; the average central estimate $SRMC_{\text{res}}^{\text{avg}}(t)$ is their midpoint and is used for the matching of the merit order.

Supplementary Note 5.2 Pumped hydro storage

The logic for the calculation of the SRMC of the pumped hydro storage (PHS) is implemented in the steps outlined below. The function aims at representing the price arbitrage this technology can use. PHS may pump when electricity prices are cheap and generate when it is expensive.

Step 1: Main variables
a) Daily gas SRMC benchmark $SRMC^{d}_{\text{gas}}(t)$ is the daily gas SRMC over the calendar day d containing time t. It provides a reference cost level against which pumped storage bids are set.

b) Classification of pumping and generating periods Each hour is classified as either a pumping or generating period:

$$\text{is_pumping}(t) = \begin{cases} 1, & h(t) \in \mathcal{H}^{\text{pumping}} \\ 0, & \text{otherwise} \end{cases} \tag{S10}$$

where $h(t)$ is the hour of day and $\mathcal{H}^{\text{pumping}} = \{22, 23, 0, 1, 2, 3, 4\}$, corresponding to 22:00-04:59. All remaining hours (05:00–21:59) are treated as generating hours. $\kappa_{\text{pumping}} = 0.60$ and $\kappa_{\text{generating}} = 0.85$ are the two fixed shares of the daily gas SRMC benchmark associated with the two periods. The plant is assumed willing to pump at moderate prices (at 60% of the daily average gas SRMC) and to generate at higher prices (at 85% of the daily average).

Step 2: Base PHS SRMC
The base PHS SRMC is set as a fixed share of the daily gas SRMC benchmark, depending on whether the hour is a pumping or generating hour.

$$SRMC^{\text{base}}_{\text{PHS}}(t) = \begin{cases} SRMC^{d}_{\text{gas}}(t) \cdot \kappa_{\text{pumping}}, & \text{is_pumping}(t) = 1 \\ SRMC^{d}_{\text{gas}}(t) \cdot \kappa_{\text{generating}}, & \text{is_pumping}(t) = 0 \end{cases} \tag{S11}$$

The base SRMC bid is capped to the global range $[L, H] = [0, 100]$ EUR/MWh, where L and H are the global SRMC floor and ceiling:

$$SRMC^{\text{base}}_{\text{PHS}}(t) \leftarrow \max\Big[L,\ \min\Big[H,\ SRMC^{\text{base}}_{\text{PHS}}(t)\Big]\Big]. \tag{S12}$$

Step 3: Construction of the min/max range
As in the case of hydro reservoir, the point estimate is widened into a flexibility buffer, representing bidding flexibility, $B = 8$ EUR/MWh, and capped to the global range $[L, H] = [0, 100]$ EUR/MWh:

$$SRMC^{\text{min}}_{\text{PHS}}(t) = \max\Big[L,\ SRMC^{\text{base}}_{\text{PHS}}(t) - B\Big], \tag{S13}$$

$$SRMC^{\text{max}}_{\text{PHS}}(t) = \min\Big[H,\ SRMC^{\text{base}}_{\text{PHS}}(t) + B\Big]. \tag{S14}$$

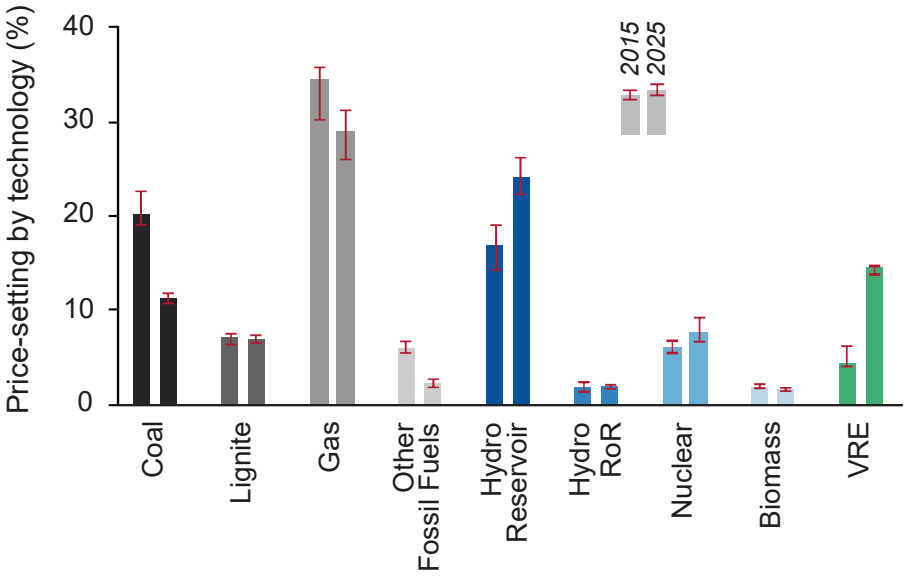
Step 4: Enforce minimum spread
In case the capping in Step 3 narrows the band to less than 8 EUR/MWh, which can occur near the 0 or 100 EUR/MWh range, the band is recentred around its own midpoint $m(t)$ and rebuilt to restore 8 EUR/MWh spread: $[\max(L, m(t) - B/2),\ \min(H, m(t) + B/2)]$, ensuring the bidding range is not narrower than the minimum spread ($B = 8$ EUR/MWh).

The function returns $\big(SRMC^{\text{min}}_{\text{PHS}}(t),\ SRMC^{\text{max}}_{\text{PHS}}(t)\big)$; the average central estimate $SRMC^{\text{avg}}_{\text{PHS}}(t)$ is their midpoint and is used for the matching of the merit order.

Under this logic, pumped storage bids a low SRMC band during "pumping" (night) hours and a high SRMC band during "generating" (day) hours, both expressed as fixed shares of the daily gas SRMC benchmark.

Supplementary Note 6 Sensitivity analysis

A sensitivity analysis of the price-setting was conducted in order to test the robustness of assumptions around various parameters of importance for the algorithm. The six principal sensitivities are given in Methods and referred to here with numbers (1)-(6). Supplementary Figure 4 shows the resulting uncertainty bands observed around the EU-weighted price-setting shares per technology, in 2015 and 2025. The analysis suggests broad robustness of the results at EU level. The main impact on the results stems from broadening price tolerances to match wholesale prices with SMRCs (1), to define cross-border coupling (2), and to define the hydropower bidding range (3).



Supplementary Figure 4: **Sensitivity analysis of price-setting shares by technology**. The graph shows the uncertainty (minimum to maximum value observed across sensitivity runs) in price-setting shares per technology as found across the different sensitivities runs for 2015 and 2025.

The largest differences in algorithm outcomes come from tightening the SRMC matching band (sensitivity 1). For instance, halving it to ±5 €/MWh, gas loses 4.4 p.p. of price-setting share in 2015, reallocated mainly to coal (+2.5 p.p.); in 2025, the shift occurs mostly from gas (-2.9 p.p.) to hydro reservoirs (+2.0 p.p.). Widening the band to ±15 €/MWh results in a +1.0 p.p. gas increase in 2015, shifting into a range of smaller decreases in different technologies, with coal (-0.4 p.p.) and reservoir hydropower (-0.5 p.p.) being the most substantial ones; in 2025, widening the band results in a +2.3 p.p. increase in gas price-setting share and a decrease in hydro reservoir price-setting by 1.8 p.p. This two-sided gas-hydro reservoir exchange reflects the increased role of strategic hydropower bidding in time; bandwidth changes have an impact in the price-setting attribution between gas technologies and other technologies price-linked with gas, such as hydro reservoirs, while their combined share remains relatively invariant. This is a change compared with 2015, where the switch occurred more between gas and coal technologies.

Widening the cross-border coupling tolerance (sensitivity 2) to ±2 €/MWh (from ±0.5 €/MWh) increases gas price-setting by around 1.1 p.p. in both 2015 and 2025, mainly at the expense of nuclear (-0.7 p.p.) and coal (-0.8 p.p.) in 2015, and at the expense of hydro reservoirs (-0.9 p.p.) in 2025.

Changing the hydropower bidding range (sensitivity 3) has nontrivial effects, particularly when widening the range, that depend strongly on which other sources are dominant in the respective power mix. At EU-level, for 2015, this results in less hydropower reservoir price-setting (-2.7 p.p.) in favour of more coal (+1.2 p.p.), nuclear (+0.8 p.p.) and run-of-river hydro (+0.6 p.p.); but for 2025, the net effect is an increase in hydropower reservoir price-setting (+1.4 p.p.) at the expense of VRE (-0.8

p.p.) and nuclear (-0.6 p.p.).

The other sensitivities, namely the hydro-reservoir gas ceiling factor (sensitivity 4), the minimum generation threshold (sensitivity 5), and the pumped-hydro charging window (sensitivity 6), generate only modest aggregated effects.

Impacts at MS level, especially in highly interconnected zones, are sometimes more pronounced than at the EU-level. For example, in a ±2 €/MWh coupling scenario (sensitivity 2) in 2025, hydro reservoir price-setting in Austria reduces by -15 p.p. in favour of gas (+7.3 p.p.), imported lignite (+4.7 p.p.) and coal (+3.9 p.p.). In a 90% hydro-gas ceiling scenario (sensitivity 4), in Poland, we observe a ±5.5 p.p. shift from coal to hydro reservoirs in 2015, and a nearly identical shift from lignite to hydro reservoirs in 2025.

The relaxed generation threshold (sensitivity 5) reshuffles results in individual BZ with price-setting generation coincidentally around the original threshold of 10 MW. In 2015, the largest difference appears for bidding zone IT_SUD where around 79 p.p. in price-setting shifts from reservoir and run-of-river hydro to gas (with gas generation reported at less than 10 MW throughout the year). However, we suspect that this may be linked to a reporting definition, with large amounts of production allocated to "other fossil fuels" in IT_SUD from 2015-2018 but seemingly shifting to the category "gas" starting in 2019. For 2025, the largest difference resulting from the relaxed generation threshold was observed in DK1 with +18 p.p. hydro run-of-river (imported) becoming price-setter instead of VRE. All of these bidding zone results did not materially affect the EU aggregate.

Overall, sensitivity appears more pronounced in 2015 than in 2025. This likely reflects the fact that SRMC levels were more homogeneous in the earlier period due to similar fossil fuel and lower CO_2 emission prices, compressing the marginal costs of coal, lignite and gas generation into a narrower range compared to 2025. This means that in 2015, the likelihood of several technologies competing within the same matching band was higher compared to 2025, and small changes in its range could have a larger effect on the outcome.

Supplementary References

[1] IBAN. Country Codes Alpha-2 & Alpha-3 (2026). URL https://www.iban.com/country-codes.

[2] Council of European Energy Regulators (CEER). Status Review of Renewable Support Schemes in Europe for 2022 and 2023. CEER Report C24-RES-84-05, Council of European Energy Regulators (CEER), Brussels, Belgium (2025). URL https://www.ceer.eu/wp-content/uploads/2025/07/RES_status_review_2022_2023_C24-RES-84-05_final.pdf. Bioenergy-specific support levels reported in Table 10.

[3] Hildmann, M., Ulbig, A. & Andersson, G. Revisiting the merit-order effect of renewable energy sources. In *2015 IEEE Power Energy Society General Meeting*, 1–1 (2015).

[4] Intergovernmental Panel on Climate Change. *2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 2: Energy* (Institute for Global Environmental Strategies (IGES), Hayama, Japan, 2006). URL https://www.ipcc-nggip.iges.or.jp/public/2006gl/vol2.html. Chapter 1, Table 1.4 (default CO_2 emission factors) and Chapter 2, Table 2.2 (stationary combustion, energy industries); Table 1.2 (default net calorific values).

[5] S&P Global Platts. Thermal Coal CIF ARA 6000 kcal/kg NAR 15-60 Day [Data set] EUR/Mt (Symbol: CSEUR00) (2026). URL https://www.spglobal.com/energy/en/commodity/coal.

[6] S&P Global Platts. FO 1%S FOB Rdam Barge [Data set] USD/Mt (Symbol: PUAAP00) (2026). URL https://www.spglobal.com/energy/en/commodity/oil.

[7] European Commission. Electrification Action Plan (COM/2026/595 final) (2026). URL https://eur-lex.europa.eu/legal-content/PT/TXT/?uri=CELEX%3A52026DC0595&qid=1784715609929.

[8] European Network of Transmission System Operators for Electricity (ENTSO-E). European Resource Adequacy Assessment (ERAA) 2025 – Annex 1: Input Data and Assumptions. https://eepublicdownloads.blob.core.windows.net/public-cdn-container/clean-documents/sdc-documents/ERAA/ERAA_2025_Annex1_InputData_ENTSOEProposal_Dec2025.pdf (2025).

[9] Kost, C., Muller, P., Sepulveda Schweiger, J., Fluri, V. & Thomsen, J. Levelized Cost of Electricity – Renewable Energy Technologies. Tech. Rep., Fraunhofer Institute for Solar Energy Systems ISE (2024). URL https://www.ise.fraunhofer.de/en/publications/studies/cost-of-electricity.html.

[10] European Union Agency for the Cooperation of Energy Regulators (ACER). Key Developments in European Gas Wholesale Markets: Gas Winter Season 2025–2026. Market Monitoring Report, EU Agency for the Cooperation of Energy Regulators, Ljubljana, Slovenia (2026). URL https://www.acer.europa.eu/sites/default/files/documents/Publications/2026-ACER-Gas-Key-Developments-winter.pdf.

[11] International Atomic Energy Agency. Power reactor information system (PRIS). IAEA, Vienna (2026). URL https://pris.iaea.org/pris/. Efficiency as the ratio between the Reactor-level net electrical capacity (MWe) and the reference thermal capacity (MWt).

[12] Helseth, A., Fodstad, M. & Mo, B. Optimal Medium-Term Hydropower Scheduling Considering Energy and Reserve Capacity Markets. *IEEE Transactions on Sustainable Energy* **7**, 934–942 (2016).

[13] Jahns, C., Podewski, C. & Weber, C. Supply curves for hydro reservoirs – Estimation and usage in large-scale electricity market models. *Energy Economics* **87**, 104696 (2020).