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SUPPLEMENTARY INFORMATION

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Start-up costs of thermal power plants in markets with increasing shares of variable renewable generation

Supplementary Note 1. The unit commitment model

Basic model for Germany

We use a mixed-integer unit commitment model with an hourly resolution that minimizes total dispatch costs of the power plant fleet while also considering the provision of balancing reserves. In contrast to a previous model version[1], the model used here does not include electric vehicles in order not to unnecessarily complicate the analysis. The model code and all input parameters are available in a public repository under http://dx.doi.org/10.5281/zenodo.259476. The code is published under the MIT open-source license.

For numerical reasons, the model is not solved for the full year in one instance; instead, 13 consecutive sequences are solved sequentially, each covering four weeks (672 hours). For each power plant block, the operational status of the first hour of each four-week sequence is fixed to the respective value of the last hour of the previous sequence. In the very first hour, the operational status of all blocks can be freely chosen without incurring start-up costs.

The model is a deterministic mixed integer linear program. Under the assumption of perfect competition, centralized cost-minimization leads to the same dispatch decisions as a perfect decentralized market coordinated by prices in which firms maximize profits. Hence, our model mimics Pareto-efficient market allocations by minimizing overall costs of energy supply, given price-inelastic hourly demand realizations, such that overall welfare is maximized. The assumption of perfect competition in turn appears to be justified as there has been a downward trend of market concentration in Germany in recent years, which is thought to continue in the context of a further transformation to higher shares of variable renewable energy sources.[2]

In order to address some of the stochastic elements present in real-world electricity markets, the model also includes a stylized representation of reserve markets. According to current German regulation, we distinguish positive and negative as well as secondary and minute (i.e. tertiary) reserves; the smallest market segment of primary reserve is not considered. Reserves do not only have to be provided, but are also (partly) activated according to historic hourly profiles. This allows—within a deterministic framework—to make the model more realistic with respect to the effects of stochastic elements on both the supply and the demand side, including forecast errors of variable renewables.[3]

In the following, we present the analytical formulation of the model. Exogenous parameters are set in lower case letters, endogenous continuous variables have an initial upper case letter, and binary variables are completely set in upper case letters. A list of sets, parameters and variables is provided in Supplementary Table 1.

The objective function (1) sums up all variable generation costs, including the sum of marginal generation costs and start-up costs of thermal plants as well as variable storage costs. If thermal plants provide positive (negative) reserves, their activation increases (decreases) respective variable costs because of corresponding additional (lower) fuel use. The same logic applies for variable storage costs. Renewables are assumed to be dispatched without variable costs. Curtailment of variable renewable energy sources may be penalized by assigning a positive value to $penalty_{res}$, which is not the case under baseline assumptions.

$$\begin{aligned} Cost = & \sum_{i,t}\left(mc_i Q_{i,t} + sc_i ST_{i,t} + sc_i ST_{i,t}^{gt}\right) + \sum_{j,t}\left(mstc_j^{in} Stin_{j,t} + mstc_j^{out} Stout_{j,t}\right) \\ & + \sum_{rsrv^{up},i,t} mc_i\, Prov_{rsrv,i,t}^{th} activ_{rsrv,t} \\ & - \sum_{rsrv^{do},i,t} mc_i\, Prov_{rsrv,i,t}^{th} activ_{rsrv,t} + \sum_{i,t} mc_i\, Prov_{mr^{up},i,t}^{gt} activ_{mr^{up},t} \\ & + \sum_{rsrv^{up},j,t} \left(mstc_j^{out} Prov_{rsrv,j,t}^{stout} - mstc_j^{in} Prov_{rsrv,j,t}^{stin}\right) activ_{rsrv,t} \\ & - \sum_{rsrv^{do},j,t} \left(mstc_j^{out} Prov_{rsrv,j,t}^{stout} - mstc_j^{in} Prov_{rsrv,j,t}^{stin}\right) activ_{rsrv,t} \\ & + \sum_{res,t} penalty_{res} Rescurt_{res,t} \end{aligned} \tag{1}$$

Equations (2a) and (2b) represent maximum and minimum generation levels of thermal blocks. The binary status variable $U_{i,t}$ is 1 if the plant is online and 0 otherwise. These equations also constrain positive and negative (spinning) reserve provision (only if generators are prequalified for reserve provision). Note that more reserves have to be provided than are actually activated in any given hour (except $activ_{rsrv,t}$ is 1). In the numerical application, the availability factor $avail_{i,t}^{th}$ is seasonally scaled with monthly average values. Equation (3) constitutes a separate restriction for non-spinning positive minute reserve provision by open cycle gas turbines. Equations (4a) to (4c) represent flexibility constraints of reserve provision. In line with the current situation in Germany, secondary reserve has to be provided within 5 minutes, minute reserve within 15 minutes.

$$Q_{i,t} + \sum_{rsrv^{up},i,t} Prov_{rsrv,i,t}^{th} \leq qmax_i^{th} avail_{i,t}^{th} U_{i,t}^{th} \qquad \forall i,t \tag{2a}$$

$$Q_{i,t} + \sum_{rsrv^{do},i,t} Prov_{rsrv,i,t}^{th} \geq qmin_i^{th} avail_{i,t}^{th} U_{i,t}^{th} \qquad \forall i,t \tag{2b}$$

$$Prov_{mr^{up},i,t}^{gt} \leq qmax_i^{th} avail_{i,t}^{th}\left(1 - U_{i,t}^{th}\right) \qquad \forall i^{gt},t \tag{3}$$

$$Prov_{rsrv,i,t}^{th} \leq 5 * grad_i^{th} qmax_i^{th} avail_{i,t}^{th} \qquad \forall rsrv^{sr},i,t \tag{4a}$$

$$Prov_{rsrv,i,t}^{th} \leq 15 * grad_i^{th} qmax_i^{th} avail_{i,t}^{th} \qquad \forall rsrv^{mr},i,t \tag{4b}$$

$$Prov_{mr^{up},i,t}^{gt} \leq 15 * grad_i^{th} qmax_i^{th} avail_{i,t}^{th} \qquad \forall i^{gt},i,t \tag{4c}$$

Equation (5a) ensures consistency between the binary status and start-up variables of thermal blocks. Equation (5b) enforces a minimum offtime. Equation (6) introduces another quasi-start-up variable related to non-spinning reserve provision by gas turbines. This is required in order to properly reflect start-up costs of these generators in the objective function.

$$ST_{i,t} \geq U_{i,t}^{th} - U_{i,t-1}^{th} \qquad \forall i,t \qquad (5a)$$

$$U_{i,t-1}^{th} - U_{i,t}^{th} \leq 1 - U_{i,tt}^{th} \qquad \forall i,t \text{ with } t \leq tt \leq t + stime_i - 1 \qquad (5b)$$

$$Prov_{mr^{up},i,t}^{gt} \leq ST_{i,t}^{gt}\,\Lambda \qquad \forall i^{gt},t \qquad (6)$$

Equations (7a) to (7c) determine hourly system integration as well as curtailment of variable renewable energy sources. These may also provide reserves in several scenarios; in this case, their reserve provision is assumed not to be flexibility-constrained. The model code includes some additional equations for special cases in which only a fraction of the installed renewable capacity is able to provide reserves.

$$Resint_{res,t} + \sum_{rsrv^{up}} Prov_{rsrv,res,t}^{res} + Rescurt_{res,t} = qmax_{res}^{res} avail_{res,t}^{res} \qquad \forall res,t \qquad (7a)$$

$$\sum_{rsrv^{do}} Prov_{rsrv,res,t}^{res} \leq Resint_{res,t} \qquad \forall res,t \qquad (7b)$$

$$Rescurt_{res,t} \leq qmax_{res}^{res} avail_{res,t}^{res} \qquad \forall res,t \qquad (7c)$$

Equation (8a) constitutes an hourly power generation capacity restriction for biomass, whereas (8b) constrains negative reserve provision. Equations (9a) and (9b) are respective flexibility restrictions for reserve provision, corresponding to (4a) and (4b). Equation (10) constrains overall biomass utilization to an overall energy cap.

$$Bio_t + \sum_{rsrv^{up}} Prov_{rsrv,t}^{bio} \leq qmax^{bio} avail_t^{bio} \qquad \forall t \qquad (8a)$$

$$\sum_{rsrv^{do}} Prov_{rsrv,t}^{bio} \leq Bio_t \qquad \forall t \qquad (8b)$$

$$Prov_{rsrv,t}^{bio} \leq 5 * grad^{bio} qmax^{bio} avail_t^{bio} \qquad \forall rsrv^{sr},t \qquad (9a)$$

$$Prov_{rsrv,t}^{bio} \leq 15 * grad^{bio} qmax^{bio} avail_t^{bio} \qquad \forall rsrv^{mr},t \qquad (9b)$$

$$\sum_t Bio_t + \sum_{rsrv^{up},t} Prov_{rsrv,t}^{bio} - \sum_{rsrv^{do},t} Prov_{rsrv,t}^{bio} \leq energy^{bio} \qquad (10)$$

Equation (11) connects the storage energy levels of subsequent periods, considering hourly charging and discharging activities, activation of positive and negative reserves, as well as respective efficiency losses. Equations (12) and (13a and b) represent upper limits on the storage level, loading capacity, and discharging capacity, respectively. A binary variable $U_{j,t}^{sto}$ ensures that storage is not loaded and discharged in the same period, which is relevant for scenarios with penalties on renewable curtailment. Equation (14a) ensures that loading-related positive reserve provision does not exceed scheduled storage loading in the wholesale market; equation (14b) respectively restricts the provision of discharging-related negative reserves. Equations (15a) and (15b) ensure that the storage facility has enough capacity to accommodate the additional energy of negative reserve provision, and to provide additional positive reserves, respectively. Here we assume that a full activation of the reserves provided in any given hour would have to be possible, despite $avail_{i,t}^{th}$ typically being smaller than 1.

$$\begin{aligned} Stlev_{j,t} = {} & Stlev_{j,t-1} + Stin_{j,t}\eta_j^{in} - \frac{Stout_{j,t}}{\eta_j^{out}} \\ & + \sum_{rsrv^{do}} \left(\frac{Prov_{rsrv,j,t}^{stout}}{\eta_j^{out}} + Prov_{rsrv,j,t}^{stin}\eta_j^{in} \right) activ_{rsrv,t} \\ & - \sum_{rsrv^{up}} \left(\frac{Prov_{rsrv,j,t}^{stout}}{\eta_j^{out}} + Prov_{rsrv,j,t}^{stin}\eta_j^{in} \right) activ_{rsrv,t} \end{aligned} \qquad \forall j,t \qquad (11)$$

$$Stlev_{j,t} \leq stlevmax_j \qquad \forall j,t \qquad (12)$$

$$Stin_{j,t} + \sum_{rsrv^{do}} Prov_{rsrv,j,t}^{stin} \leq stinmax_j (1 - U_{j,t}^{sto}) \qquad \forall j,t \qquad (13a)$$

$$Stout_{j,t} + \sum_{rsrv^{up}} Prov_{rsrv,j,t}^{stout} \leq stoutmax_j U_{j,t}^{sto} \qquad \forall j,t \qquad (13b)$$

$$\sum_{rsrv^{up}} Prov_{rsrv,j,t}^{stin} \leq Stin_{j,t} \qquad \forall j,t \qquad (14a)$$

$$\sum_{rsrv^{do}} Prov_{rsrv,j,t}^{stout} \leq Stout_{j,t} \qquad \forall j,t \qquad (14b)$$

$$\left(Stin_{j,t} + \sum_{rsrv^{do}} Prov_{rsrv,j,t}^{stin} \right) \eta_j^{in} \leq stlevmax_j - Stlev_{j,t-1} \qquad \forall j,t \qquad (15a)$$

$$\frac{Stout_{j,t} + \sum_{rsrv^{up}} Prov_{rsrv,j,t}^{stout}}{\eta_j^{out}} \leq Stlev_{j,t-1} \qquad \forall j,t \qquad (15b)$$

The wholesale market clearing condition (16) ensures that overall supply equals demand in all hours, considering cross-border exchange. Equations (17a) and (17b) are respective clearing conditions for the four reserve market segments.

$$\begin{aligned} & \sum_i Q_{i,t} + \sum_{res} Resint_{res,t} + Bio_t + othergen_t \\ & \quad + \sum_j (Stout_{j,t} - Stin_{j,t}) = dem_t^{whls} + cbex_t^{exog} \end{aligned} \qquad \forall t \qquad (16)$$

$$\begin{aligned} & \sum_i Prov_{rsrv,i,t}^{th} + \sum_{res} Prov_{rsrv,res,t}^{res} + Prov_{rsrv,t}^{bio} \\ & \quad + \sum_j \left(Prov_{rsrv,j,t}^{stout} + Prov_{rsrv,j,t}^{stin} \right) = dem_{rsrv,t}^{rsrv} \end{aligned} \qquad \forall rsrv \neq mr^{up}, t \qquad (17a)$$

$$\sum_{i} Prov^{th}_{mr^{up},i,t} + \sum_{i} Prov^{gt}_{mr^{up},i,t} + \sum_{res} Prov^{res}_{mr^{up},res,t} + Prov^{bio}_{mr^{up},t} + \sum_{j} \left(Prov^{stout}_{mr^{up},j,t} + Prov^{stin}_{mr^{up},j,t} \right) = dem^{rsrv}_{mr^{up},t} \qquad \forall t \qquad (17b)$$

It should be noted that thermal power plants (including nuclear power) are modelled as single blocks, subject to start-up costs and restrictions, while variable renewables and pumped hydro storage are represented as aggregated capacities which are assumed to be perfectly flexible. Accordingly, thermal generation $Q_{i,t}$ is flexibility-constrained, whereas variable renewable feed-in $Resint_{res,t}$ and storage output $Stout_{j,t}$ are not. Flexibility of power generation from biomass Bio_t depends on scenario assumptions. Inflexible power generation from run-of-river hydro and waste incineration $othergen_t$ are treated as constant exogenous input parameters. Hydro generation is seasonally scaled according to historic monthly average values.

Extended model with stylized neighbouring countries

In the basic model, cross-border power exchange is treated as an exogenous parameter. This parameter consists of a historic hourly pattern of net exports from Germany, and is assumed not to change in 2020 and 2030 in the basic model. In order to explore the implications of future changes in the cross-border exchange pattern, we carry out a sensitivity analysis in which power flows between Germany and its electric neighbours are modelled as endogenous variables (compare Supplementary Note 4, subsection "Endogenous cross-border exchange"). This also requires modelling neighbouring countries' power systems and making numerous additional parameter assumptions. While the analytical formulation of the extended model is explained in the following, additional input parameters are presented in Supplementary Note 2.

When modelling neighbouring countries, we do not follow a detailed unit commitment approach because of limited data availability and numerical challenges of solving large-scale unit commitment models. Instead, we use a simplified approach. We represent different generation technologies in neighbouring countries not on a block level, but as aggregate capacities, drawing on a stylized linear formulation for aggregate load change costs. Further, we abstract from modelling balancing reserves in neighbouring countries. Supplementary Table 2 shows additional sets, parameters and variables for the extended model.

The extended model requires several additional equations as well as modifications of existing ones. First, the objective function is augmented with additional terms that reflect the variable costs of dispatchable generators and storage in neighbouring countries (1'). As regards dispatchable generators, not only the sum of marginal production costs is included, but also hourly load change costs of aggregate thermal dispatchable technologies in neighbouring countries.

$$\begin{aligned}
\dots + \sum_{dispnc,t,nc} & mc_{dispnc} Qdisp_{dispnc,t,nc} \\
+ \sum_{dispnc,t,nc} & \left(mc_{dispnc}^{up} Qdisp_{dispnc,t,nc}^{up} + mc_{dispnc}^{do} Qdisp_{dispnc,t,nc}^{do}\right) \\
+ \sum_{jnc,t,nc} & \left(mstc_{jnc}^{in} Stin_{jnc,t,nc} + mstc_{jnc}^{out} Stout_{jnc,t,nc}\right)
\end{aligned} \qquad (1')$$

Next, the German market clearing condition is modified to include endogenous cross-border exchange $\sum_l inc_{l,DE} Cbex_{l,t}^{endog}$ instead of exogenous net exports (16').

$$\begin{aligned}
\sum_i Q_{i,t} + \sum_{res} Resint_{res,t} + Bio_t + othergen_t & \\
+ \sum_j (Stout_{j,t} - Stin_{j,t}) & \qquad \forall t \qquad (16') \\
= dem_t^{whls} + \sum_l inc_{l,DE} Cbex_{l,t}^{endog} &
\end{aligned}$$

An additional market clearing condition ensures that (wholesale) supply matches demand in neighbouring countries, again considering cross-border exchange (18). Here, run-of-river hydro power is treated as an exogenous parameter $ror_{t,nc}$. In contrast, hydro reservoirs are included in $Qdisp_{dispnc,t,nc}$.

$$\begin{aligned}
\sum_{dispnc} Qdisp_{dispnc,t,nc} + \sum_{res} Qres_{res,t,nc} + ror_{t,nc} & \\
+ \sum_{jnc} (Stout_{jnc,t,nc} - Stin_{jnc,t,nc}) & \qquad \forall t, nc \qquad (18) \\
= dem_{t,nc}^{nc} + \sum_l inc_{l,nc} Cbex_{l,t}^{endog} &
\end{aligned}$$

Analogous to equation (2a), there is a maximum generation restriction for aggregate dispatchable capacity in neighbouring countries (19a). Equation (19b) connects the generation levels of subsequent periods and defines positive and negative load changes.

$$Qdisp_{dispnc,t,nc} \leq qmax_{dispnc,nc}^{dispnc} \qquad \forall dispnc, t, nc \qquad (19a)$$

$$\begin{aligned}
Qdisp_{dispnc,t,nc} = Qdisp_{dispnc,t-1,nc} + Qdisp_{dispnc,t,nc}^{up} & \\
- Qdisp_{dispnc,t,nc}^{do} &
\end{aligned} \qquad \forall dispnc, t, nc \qquad (19b)$$

Similar to equation (10) in the German basic model, equation (20) constrains overall power generation from biomass and hydro reservoirs in neighbouring countries to an overall energy cap.

$$\sum_t Qdisp_{dispnc,t,nc} \leq energy_{dispnc,nc}^{dispnc} \qquad \forall dispnc = \{bio, reservoir\}, nc \qquad (20)$$

Equation (21) constrains power generation from variable renewable energy sources in neighbouring countries to installed capacity, considering variable hourly availability.

$$Qres_{res,t,nc} \leq qmax^{res}_{res,nc} avail^{res}_{res,t,nc} \qquad \forall res, t, nc \qquad (21)$$

Mirroring equations (11-14b) in the basic model, equations (22-24b) represent power storage in neighbouring countries. Equation (11) connects the storage energy levels of subsequent periods, considering hourly charging and discharging activities and respective efficiency losses. Equation (23), (24a) and (24b) constitute upper limits on the storage level, loading capacity, and discharging capacity. Again, a binary variable $U^{sto}_{jnc,t,nc}$ ensures that storage is not loaded and discharged in the same period.

$$Stlev_{jnc,t,nc} = Stlev_{jnc,t-1,nc} + Stin_{jnc,t,nc}\eta^{in}_{jnc} - \frac{Stout_{jnc,t,nc}}{\eta^{out}_{jnc}} \qquad \forall jnc, t, nc \qquad (22)$$

$$Stlev_{jnc,t,nc} \leq stlevmax_{jnc,nc} \qquad \forall jnc, t, nc \qquad (23)$$

$$Stin_{jnc,t,nc} \leq stinmax_{jnc,nc}(1 - U^{sto}_{jnc,t,nc}) \qquad \forall jnc, t, nc \qquad (24a)$$

$$Stout_{jnc,t,nc} \leq stoutmax_{jnc,nc} U^{sto}_{jnc,t,nc} \qquad \forall jnc, t, nc \qquad (24b)$$

Supplementary Note 2. More details on input parameters

We apply the basic model to the German power system using scenarios of the years 2013, 2020, and 2030, drawing on the medium projections of the German Grid Development Plan (*Netzentwicklungsplan*, NEP). More precisely, we use the medium projection "B" of the so-called 2025 version of the Grid development plan[4] and interpolate capacities for the years 2020 and 2030. A similar methodology has been applied before.[1] All input data is available together with the open-source model under http://dx.doi.org/10.5281/zenodo.259476. The following sections contain further details on input data for the basic (German) model complementary to the information provided in the main article, and additional input parameters required for the extended model.

Generation capacities

As the power plant list of the NEP does not clearly differentiate between combined cycle gas turbines (CCGT) and open cycle gas turbines (OCGT), own assumptions are made based on various sources. CCGT plants constitute the major fraction (28 GW in 2030) and OCGT plants the minor one (7 GW in 2030). As for pumped hydro storage, a substantial capacity increase is projected from around 6 GW in 2013 to 8 GW in 2020 and 11 GW in 2030. We abstract from other storage technologies, i.e. the set J only includes pumped hydro storage.

Aggregated NEP capacities are translated into a block-sharp power plant portfolio by drawing on the official NEP power plant list and DIW Berlin's own power plant database. In order to reduce the computational burden of the program, thermal blocks smaller than 100 MW are aggregated to stylized 100 MW blocks. Shut-down dates of existing blocks and future capacity additions are derived from the NEP power plant list and are complemented with own assumptions, particularly regarding the aggregation of small power plants. For the 2030 scenario, we add 5 GW of oil-fired gas turbines as backstop peaker plants, as it turns out that additional capacity is required particularly for positive reserve provision during a few hours of the year.

Power plants that operate in a combined heat and power (CHP) mode are subject to additional operational constraints, depending on daily average ambient temperatures of the year 2013 in Germany and a respective district heating demand profile of a large German municipality. We further differentiate between public and industrial CHP plants, as well as other industrial plants. More details on respective dispatch restrictions can be found in the open-source model code. Loosely reflecting the German government's CHP targets, the overall CHP capacity increases from around 33 GW in 2013 to 37 GW in 2030. By 2030, more than 60% of the combined hard-coal, CCGT and gas-fired OCGT capacity faces some CHP restrictions. Assumptions on the flexibility of CHP generators are held constant over all scenarios in order to reduce complexity and ease comparisons between the scenarios. What is more, properly modelling future changes of CHP restrictions due to additional heat storage facilities or other flexibilisation measures would pose considerable methodological as well as data-related challenges. Accordingly, it appears reasonable not to vary CHP flexibility assumptions between scenarios.

Unit commitment parameters

As regards unit commitment modelling of thermal plants, four parameters are of particular importance: minimum load requirements, minimum offtime, start-up fuel costs and start-up depreciation costs (Supplementary Table 3). Under baseline assumptions, these unit commitment parameters, which draw on DIW Berlin's database and a DIW Data Documentation[5], do not change in future scenarios. In a sensitivity analysis, we use lower minimum load parameters.

Start-up costs depend on fuel and CO_2 prices as well as depreciation costs. In reality, start-up costs also depend on offtime, i.e. on a generator's temperature at the time it is started up again. As modelling offtime-dependent start-up costs is computationally demanding, we use a simplified approach: nuclear plants are generally assumed to carry out only hot starts, requiring only 30% of the cold-start fuel requirement provided in Supplementary Table 3. Lignite and hard coal plants are assumed to carry out warm starts with 50% of the typical cold-start fuel requirement. Only generators fuelled by natural gas and oil are assumed to typically carry out cold starts, incurring 100% of the start-up fuel requirements presented in the table. With 2013 cost data, this results in typical start-up costs of around €250,000 for a 1.3 GW nuclear block, €50,000 or 70,000 for 800 MW lignite or hard coal blocks, and around €70,000 for a 500 MW CCGT block.

Power generation from renewable sources

Hourly power generation from variable renewables is based on actual 2013 feed-in data provided by German TSOs. Hourly availability factors are calculated by relating hourly feed-in to respective installed capacity, properly taking into account capacity additions during the year. For 2020 and 2030, these hourly availability factors are then multiplied with installed capacities of the respective scenario.

As regards power generation from biomass, we use yearly energy caps of 41 TWh in 2013, 46 TWh in 2020, and 52 TWh in 2030. We assume generators to be completely inflexible in 2013, i.e. hourly generation from biomass is fixed to a yearly average level. This reflects actual incentives of biomass power plants in 2013 caused by a largely time-invariant feed-in tariff. In future scenarios, we assume biomass to be more flexible, also reflecting changes in the legislation. According to the current Renewable Energy Sources Act (EEG), all new biomass power plants now receive a sliding market premium instead of a feed-in tariff. Moreover, the EEG provides a so-called flexibility premium which gives incentives to design the plants for higher peak loads and lower full load hours. In 2020, half of the available energy cap is thus assumed to be used flexibly, and the other half is fixed to a yearly average value. In 2030, the biomass cap can be allocated fully flexibly among hours (within each 4-week sequence), only restricted by available generation capacity (equation 8a). Run-of-river hydro power is assumed to produce at constant hourly levels which seasonally vary between the 13 modelled 4-week sequences according to historic data.

Load, cross-border exchange, and balancing reserves

Hourly load is derived from 2013 TSO data in line with the assumptions made in the NEP scenario framework. Accordingly, the load profile is assumed not to change in 2020 or 2030 compared to 2013 levels. The total yearly net consumption is 542 TWh, including grid losses, with a peak load of 84 GW. Data on net power exchange with neighbouring countries is taken from public European TSO sources (ENTSO-E). Hourly exchange values are fixed to historic 2013 levels also in 2020 and 2030 in the basic model. Supplementary Figure 1 shows the correlation between cross-border exchange and variable renewable power generation (sum of PV, onshore and offshore wind power) in the historic German 2013 data. While there is substantial variation between single hours, which amongst other factors is caused by different load situations, there is a clear tendency of increasing exports in hours of high feed-in by variable renewable energy sources.

Input data on the hourly provision and activation of positive and negative secondary and minute reserves is taken from German TSOs (again, using 2013 data). In every hour, an exogenously specified fraction of provided reserves is activated according to historic data. More precisely, we use the respective maxima of quarter-hourly values provided by TSOs. Importantly, all provided reserves are required to be activated with this hourly share. This prevents the model from selecting only such technologies that have low costs of reserve provision, but potentially high costs of activation. We hold reserve requirements constant between 2013 and 2030. This allows for better comparisons between scenarios. Stagnating reserve requirements also appear to be plausible despite the growth in variable renewable power sources. In recent years, reserve requirements have even decreased, triggered by various institutional and regulatory changes such as shorter lead times and commitment periods, and larger balancing areas. Moreover, future improvements are foreseeable such as the dynamic dimensioning of reserve requirements.

In contrast, scenarios differ with respect to the prequalification of different power plants to provide reserves. With the exception of nuclear plants, large thermal generators with a block size above 100 MW are generally assumed to be eligible to provide all reserve qualities, given that the respective block is online, and restricted by flexibility constraints (equations 4a and 4b). Smaller thermal plants are generally assumed not be qualified for reserve provision. Variable renewables and biomass are assumed not to provide any reserves in 2013, which largely reflects the actual situation in Germany. Anticipating institutional and technological changes, we relax this assumption by 2030 and assume variable renewables and biomass to be fully eligible to provide all types of reserves by this year. In 2020, we assume 50% of the respective renewable fleet to be able to provide reserves. This special case requires several additional model equations which are not listed above, but documented in the source code. We further assume that all open-cycle gas (or oil) turbines are able to provide non-spinning positive minute reserve. Their activation then leads to additional start-ups $ST_{i,t}^{gt}$, the costs of which are considered in the objective function.

Additional input parameters for the extended model with stylized neighbouring countries

The extended model—which is only applied to the years 2013 and 2030—requires a range of additional inputs parameters for neighbouring countries. We include the German electric neighbours Austria (AT), Belgium (BE), Switzerland (CH), Czech Republic (CZ), Denmark (DK), France (FR), Luxembourg (LU), the Netherlands (NL), Poland (PL), and Sweden (SE). In order to make country-specific parameter assumptions that are consistent across all neighbouring countries, we generally draw on the so-called Vision 3 of the most recent Ten Year Network Development Plan (TYNDP) published by European TSOs.[6] Input data for Germany does not change as compared to the basic model.

Installed generation capacities in neighbouring countries are illustrated in Supplementary Figure 2. There is a shift toward variable renewables in all countries, although generally less pronounced than in Germany. At the same time, nuclear and coal-fired capacity decreases. Entso-E[6] only provides a combined category for run-of-river hydro, hydro reservoirs and pumped storage. We accordingly separate these technologies, drawing on own assumptions and additional sources such as the Open Power System Data Platform (http://open-power-system-data.org/, Data Package National generation capacity, version 2016-10-27; primary data from ENTSOE, EUROSTAT, e-control, ELIA, UN Statistical Office, BFE, ERU, DEA, RTE 2014, RTE 2015, Tennet NL, CIRE, and Svensk Energi). Following Entso-E, we abstract from other storage technologies than pumped hydro, i.e. the set JNC only includes this technology.

Yearly energy budgets for run-of-river, hydro reservoirs and biomass generators are also derived from Entso-E[6]. Mirroring the German biomass assumptions, biomass generators in neighbouring countries are also assumed to be perfectly inflexible in 2013, i.e. generating on a constant average level, and perfectly flexible in 2030. Because of limited data availability, we make the simplifying assumption that run-of-river hydro power is generated on a constant average level throughout the year. For hydro reservoirs—which are relevant technologies in Austria, Switzerland, France, and Sweden—we assume a lower bound of hourly generation equal to 1/8760 of half the reservoirs' yearly energy budgets. The remaining half of the energy budget may freely be allocated within each of the 13 four-week blocks, constrained by equations (19a) and (20). This stylized approach allows representing partly flexible power generation from hydro reservoirs without engaging in—for this sensitivity, prohibitively complex—detailed reservoir modelling.

As for marginal generation costs, we use the same fuel and CO_2 price assumptions as in the German basic model. Generator efficiencies are derived from Entso-E[6]. This results in marginal generation costs as shown in Supplementary Table 4. The table also include stylized marginal load change costs of thermal power plants, which lean on an NREL study[7]. Dispatchable hydro and biomass generators are assumed not to have load change costs.

Hourly availability of onshore and offshore wind power in neighbouring countries is taken from the European Commission's EMHIRES data set (https://ec.europa.eu/jrc/en/scientific-tool/emhires). For PV, we have to resort to the German profile as a proxy because of limited data availability. Electric load profiles of neighbouring countries are derived from the Open Power System Data Platform for 2013 (http://open-power-system-data.org/, Data Package Time series, version 2016-10-28; primary data from CEPS, PSE, Amprion, BNetzA and Netztransparenz.de, Svenska Kraftnaet, TransnetBW, 50Hertz, TenneT, ENTSO-E Data Portal, Energinet.dk) and from Entso-E[6] for 2030.

Our stylized model of the interconnection of Germany and its electric neighbours includes 21 links between the 11 countries considered. The network topology is presented in Supplementary Table 5 in the form of an incidence matrix. This table also includes net transfer capacity (NTC) values. These are derived from historic TSO data for 2013 and from Entso-E[6] for 2030. We assume that NTC values are constant over all hours of the year and symmetric with respect to power flows in both directions.

Supplementary Note 3. Separation of effects with alternative sequence

In the main article, we separate the effects of

1) additional renewables,
2) flexible (and increased) biomass capacity,
3) increased pumped storage,
4) thermal portfolio changes,
5) changing assumptions on reserve provision, and finally
6) increasing fuel and carbon prices.

The results generally depend on the particular sequence of the decomposition analysis. Other sequences would also be possible—although not all sequences would be numerically feasible.

In the following, we present the results of an alternative sequence on the separation of start-up costs. Other (meaningful) sequences may also be evaluated to raise complementary insights. We look at the following sequence:

1) Increasing fuel and carbon price prices,
2) additional renewables,
3) thermal portfolio changes
4) flexible (and increased) biomass capacity combined with increased pumped storage, and
5) changing assumptions on reserve provision.

The direction of effects is generally similar to the sequence discussed in the main article (Supplementary Figure 3). As before, growing fuel and carbon prices, increases in renewable capacity, and changing assumptions on reserve provision all have a positive influence on start-up costs, while the other factors have opposite effects. Yet the size of effects differs somewhat. The increase in start-up costs triggered by renewables alone would be even higher (+148%) than under the previous sequence. Yet the share of start-up costs in overall yearly variable costs (after first changing fuel and carbon prices) would grow to only 1.3% in this setting. Despite higher absolute start-up costs, this share would nonetheless be smaller than in the sequence presented in the main article (1.6%), as other variable costs also increase under the assumed fuel and carbon price changes. Accordingly, start-up costs should not become a major concern even under the assumption that only fuel and carbon prices as well as renewable capacities increase, but no other changes would take place in the system. It should be noted that, in order to ensure numerical feasibility, we allow for using a penalized backstop peak technology in the model run where the thermal portfolio changes are assessed. Likewise, we combine the changes of biomass pumped storage capacity in order to ensure feasibility.

Supplementary Note 4. Sensitivity analyses

We carry out additional sensitivity analyses for the years 2020 and 2030 in order to assess the effects of alternative flexibility assumptions. These differ with respect to specific input parameters:

- **"More RES"**: Here we assume that the capacities of variable renewables, i.e. onshore wind power, offshore wind power and PV, are 10% larger compared to the baseline in 2020 and 20% larger in 2030. Accordingly, the need for flexibility in the system should increase.
- **"Less storage"**: In this sensitivity we assume that the capacity of pumped hydro storage remains constant at the 2013 level. As a consequence, storage capacity is 40% lower in 2030 compared to the baseline. This reflects the fact that pumped storage capacity expansions are currently not economic in Germany. In fact, there have not been any investment decisions worth mentioning in German pumped storage projects in recent years. While the motivation of this sensitivity is rather specific to the current German situation, results may be considered to have a rather general character with respect to the effects of changing storage capacities.
- **"Lower minload"**: The minimum load level of all thermal power plants is assumed to decrease by 25% compared to the baseline in 2020 and by 50% in 2030. Taking into account that future flexibility characteristics of the power plant portfolio are highly uncertain, this sensitivity may be considered as a rather optimistic perspective of thermal flexibility. In the future, minimum generation levels may decrease either due to retrofits of existing plants or because of new-builds that are designed for increased flexibility.
- **"Less curtailment"**: While curtailment of variable renewables does not incur any direct costs under baseline assumptions, it is penalized in the objective function in this sensitivity. Such costs can be caused by renewable support schemes, i.e. feed-in tariffs or market premiums. To fully reflect the real situation in Germany, a thorough assessment of current and future support instruments and their respective levels would be required, differentiating between technologies, age classes and plant sizes. Instead, we use a stylized, technology-invariant penalty of €100/MWh. This should serve to roughly reflect the effects of actual German renewable support schemes.
- **"Smoother wind profiles"**: Linearly scaling historic renewable feed-in patterns with future assumptions of installed capacity neglects potential smoothing effects, particularly with respect to onshore wind power. Such future smoothing may result from alternative geographic dispersion of renewable plants or generator design changes (cp. also Supplementary Note 5). We thus test the effects of three synthetically smoothed onshore wind profiles. Offshore wind and PV profiles are not changed, as both have comparatively small potentials for future smoothing.
- **"Alternative exogenous cross-border exchange"**: The future development of cross-border power exchange is highly uncertain and depends, amongst other factors, on power system developments in neighbouring countries, transmission infrastructure, and regulatory measures. In this sensitivity, we study the implications of changing cross-border exchange by linearly scaling the historic exchange profile for the year 2030. We use the scaling factors 2, 0.5, and 0. The factor 2 implies that net exchange is twice as high as in the baseline in every hour of the year. Such a development may result from future increases in interconnection capacity. Conversely, the scaling factors 0.5 and 0 imply that hourly net cross-border exchange is only half of the historic 2013 levels, or zero, respectively. This may occur if neighbouring countries also deploy additional variable renewable generators with similar generation profiles

on a massive scale, or take measures to control load flows, such that German power exports in hours with high availability of variable renewables are less feasible.

- **"Endogenous cross-border exchange"**: Extending the previously mentioned sensitivity, we further explore the implications of alternative cross-border exchange patterns by modelling power flows between Germany and its electric neighbours as endogenous variables. This requires additional model equations (Supplementary Note 1, subsection "Extended model with stylized neighbouring countries") and additional parameter assumptions (Supplementary Note 2, subsection "Additional input parameters for the extended model with stylized neighbouring countries"). We then apply the extended model to the years 2013 and 2030, and additionally separate the effects of different power system changes in Germany and its electric neighbours. In doing so, we compare 2030 model outcomes with a 2013 simulation of the extended model, and not with the 2013 basic model. This way we avoid potential misinterpretations of artefacts arising from comparing the basic and the extended model.

To varying degrees, overall results are sensitive to deviating assumptions on renewable expansion, storage capacity deployment, changes in the minimum load level of thermal power plants, volatility of wind power profiles, and changes in cross-border power exchange. They are in contrast hardly sensitive with respect to decreased renewable curtailment. Yet effects vary substantially for different technologies. As results hardly change for the categories "Nuclear" and "Other" thermal generators, these are mostly not shown in the following figures in order to improve readability.

"More RES"

The "More RES" sensitivity assumes additional capacities of variable renewables of +10% by 2020 and +20% by 2030. The shares of variable renewables accordingly increase to 26% in 2020 and 40% in 2030, which can be interpreted as an accelerated transition from fossil to renewable power sources. Overall start-up costs increase roughly proportionally by +13% (+€11 million) in 2020 and +18% (+€26 million) in 2030, compared to respective baseline results. This is largely driven by increased cycling needs of hard coal plants and–to a smaller extent–lignite plants (Supplementary Figure 4). That is, a further expansion of variable renewables—ceteris paribus—predominantly increases cycling needs of former base- and mid-load generators with low variable costs. This reconfirms earlier findings in other power systems.[8]

"Less storage"

Assuming "Less storage", i.e. abstracting from future storage expansion, leads in 2030 to a somewhat stronger overall increase of start-up costs compared to the one observed in the "More RES" sensitivity (Supplementary Figure 5). In 2030, the assumed decrease in storage capacity of around 40% compared to the baseline results in a 28% increase of overall start-up costs (+€40 million). That is, thermal cycling needs may not only increase because of additional, renewable-induced flexibility requirements, but also in case of supply-side flexibility losses, which are comparatively small in terms of capacity. Yet the distribution of changes among generation technologies is rather different compared to "More RES". Under the assumption of lower storage capacities, oil-fired plants show in 2030 the largest increase in cycling needs, both in absolute and relative terms, closely followed by CCGT plants (in absolute terms).

In other words, flexible mid- and peak-load plants now have to provide a substantial part of the flexibility that is provided by additional storage in the baseline, both in wholesale and reserve markets. Storage and flexible mid- and peak-load plants may thus be considered as competing flexibility options. A study that also considers investment decisions comes to similar conclusions.[9] A comparable effect is likely to occur with respect to different assumptions on demand-side flexibility, as the power system effects of storage and load shifting are very similar. A study on the Irish system conversely finds that lower storage capacities may—in specific settings—*decrease* the cycling needs of coal-fired plants until very high wind shares are reached.[8] This finding is driven by primary reserve provision of coal plants.

"Lower minload"

Results of the "Lower minload" sensitivity show that increasing flexibility of thermal power plants has an opposite effect on cycling needs as compared to the previously discussed sensitivities (Supplementary Figure 6). Under the assumption of decreased minimum load requirements of -25% in 2020 and -50% in 2030 compared to the baseline, overall start-up costs decrease by 21% (-€18 million) and 32% (-€46 million), respectively, as more generators remain online in periods of low net load. In the 2020 model runs, the absolute effect is most pronounced for hard coal plants, while in 2030 start-up cost reductions of CCGT plants dominate. Lignite plants show the strongest relative decrease. This means that lower minimum load requirements would allow lignite plants to largely preserve their merit-order position as base-load generators even under substantial expansion of variable renewables. It should be noted that such increased flexibility of thermal plants may involve not only additional investments, but also additional variable costs due to lower thermal efficiency which we abstract from in this analysis.

"Less curtailment"

The "Less curtailment" sensitivity shows that a preference for not curtailing renewable surpluses has a comparatively small effect on model outcomes (Supplementary Figure 7). Assuming a curtailment penalty of €100/MWh in the objective function, overall start-up costs increase by less than a million Euro in 2020, and decrease very slightly in 2030 compared to the baseline. Outcomes for 2020 are driven by increased cycling of nuclear power plants, which have the lowest marginal energy costs (but high start-up costs) and are thus the last to go offline in periods of excess renewable supply. In contrast, results for 2030 are driven by changes in start-ups of oil- and lignite-fired power plants. Additional model runs not shown here indicate that results would not change much even under a rather extreme penalty of €1000/MWh. The reason is that renewable curtailment is generally low in the modelled scenarios because of steep surplus-duration curves with high hourly peak surpluses and comparatively low yearly surplus energy.[10] Another reason for low curtailment—despite limited export opportunities—is the strong increase in pumped storage capacity assumed in the NEP scenarios. In the 2030 baseline, only around 2.6 TWh of variable renewable energy has to be curtailed, corresponding to 1.4% of overall potential wind and solar power generation. This value decreases to 1.4 TWh (0.8%) under the assumption of a €100/MWh curtailment penalty. It hardly decreases further under a €1000/MWh penalty, as the remaining peak surpluses cannot be integrated with the assumed storage capacities, irrespective of thermal start-up costs.

According to these results, the effect of the actual renewable support scheme in Germany on start-up costs should be very small. Yet our analysis only provides a general indication as we, amongst other simplifications, do not differentiate between feed-in tariffs with feed-in guarantees, which may correspond to very high penalties in the objective function, and sliding market premiums, which limit negative prices to (negative) support levels. Irrespective of future changes in German renewable support policies, both schemes will still be present to some extent in the year 2030 due to their 20-year duration. A complementary analysis also uses penalties of €100/MWh and €1000/MWh to study the effect of lower renewable curtailment on dispatch and investment decisions in Germany and shows for scenarios of 2024 and 2034 that the marginal system costs of reducing renewable curtailment increase strongly, while renewable shares hardly change.[9]

"Smoother wind profiles"

We generate synthetically smoothed onshore wind profiles as follows. We first increase historic hourly availability factors by a time-invariant value corresponding to 10%, 25% or 50% of average yearly availability. We then proportionally decrease all hourly values again with corresponding factors of 1.1^{-1}, 1.25^{-1} or 1.5^{-1}, respectively, such that the overall yearly energy delivered by onshore wind generators does not change. This causes the standard deviation of hourly onshore wind generation to decrease from 0.15 in the baseline to 0.14, 0.12 or 0.10, respectively. The smoothing effect on availability-duration curves is shown in Supplementary Figure 8.

Model outcomes show that smoother wind profiles would reduce start-up costs. In the most extreme case modelled here, where the wind profile's standard deviation is reduced from around 0.15 to 0.10, overall start-up costs would decrease by 25% (-€36 million, Supplementary Figure 9). While all thermal technologies would be required to cycle less, the absolute effect is largest for CCGT plants. This is not surprising as these plants have to balance the largest part of renewable variability in this scenario. Yet lignite plants also need to be started up much less–particularly in relative terms. This is because of lower renewable surplus generation (cp. the left-hand side of the availability-duration curve), such that base-load plants have to shut down less frequently. In the cases with less extreme smoothing, effects are qualitatively similar, but quantitatively smaller. It should be noted that the synthetic profiles used here only illustrate the general effect of smoother wind power. The question how real-world future smoothing related to different geographical distributions and alternative generator designs would exactly change wind power profiles, and in turn start-up costs, is left for future research.

"Alternative exogenous cross-border exchange"

If cross-border exchange doubles in every hour compared to the 2030 baseline, overall start-up costs in Germany decline by around €23 million, or -16% (Supplementary Figure 10). As shown above, hours of German net exports (imports) are correlated with hours of high (low) renewable availability in the historic exchange pattern. Increased cross-border exchange thus smooths German net load and the operation of thermal power plants. In contrast, start-up costs increase by €15 million (+11%) if hourly exchange is only half of the historic level, and by €35 million (+25%) in case no exchange is possible at all. These findings connect to previous literature, according to which cross-border exchange is an important option for providing power system flexibility for the integration of variable renewable energy sources.[11,12,13]

Linearly scaling historic exchange patterns appears to be a valid approach under the assumption that historic differences between Germany's and neighbouring countries' power systems, which have given rise to the historic exchange profile, also persist in the future. Given that overall start-up costs decrease by only -16% if hourly exchange doubles and increase by a mere +11% if exchange is halved, we conclude that the results of our basic model are robust with respect to higher or lower exchange opportunities under this basic assumption.

"Endogenous cross-border exchange"

As opposed to the sensitivity presented above, we now give up the implicit assumption that the hourly profile of cross-border exchange does not change, but model exchange as an endogenous variable. This requires to also model the dispatch of neighbouring power systems as endogenous variables. As these cannot be modelled with the same level of detail as the German one in this application, our approach to modelling cross-border flows necessarily remains stylized. We do not expect to perfectly replicate real-world 2013 outcomes, nor the results of our basic model. Yet we assume that any limitations of the extended model should largely even out when looking at the differences between 2013 and 2030 outcomes of the extended model. We thus compare results of the extended model for both 2013 and 2030 in the following (and do not look at the 2013 baseline).

We find that overall yearly start-up costs of thermal generators in Germany hardly change between 2013 and 2030 in the extended model (around €68 million in 2013 and €66 million in 2030). Yet the composition of overall start-up cost changes considerably (Supplementary Figure 11). While hard coal plants account for the largest part of start-up costs in 2013, there is a shift towards CCGT plants by 2030. A qualitatively similar development was also observed in the basic model.

On the first glance, this finding may be considered to put the outcomes of our basic model—according to which start-up costs moderately increase in the context of German RES expansion—somewhat into perspective: start-up costs may not increase if additional flexibility resources of the European interconnection could be utilized. In the following, we shed some more light on the question where this additional flexibility originates from.

To do so, we separate the effects of different parameter changes between 2013 and 2030 by means of additional model runs, methodologically comparable to the separation exercise illustrated in the main article. Departing from the 2013 model run, we first carry out a simulation in which only the German part of the model is parametrized to the baseline 2030 assumptions, while all neighbouring countries as well as NTCs are still calibrated to the year 2013 ("Changes in Germany"). We subsequently increase installed variable renewable capacity in neighbouring countries to 2030 levels ("Additional RES neighbours"). Then, the remaining generation portfolio as well as load in neighbouring countries are also updated to 2030 levels ("Other changes neighbours"). Finally, NTC values are increased to 2030 assumptions ("NTC changes").

Model results show that—all other parameters being constant—both the (cumulative) changes in Germany and the expansion of fluctuating renewable energy sources in neighbouring countries would substantially increase start-up costs of thermal power plants in Germany (Supplementary Figure 12). The changes in Germany alone would cause start-up costs to increase to around €108 million (+60%). Although this is a little less than in the basic model, our results may be considered fairly robust also in the extended model with endogenous cross-border exchange. Together with the expansion of variable renewables in neighbouring countries, start-up costs would nearly double from €68 million to €131 million (+93%). Other changes in neighbouring countries—i.e. increasing load and additional power storage—conversely cause start-up costs in Germany to decrease again, as these allow neighbouring countries to increase their imports from Germany in hours of high German renewable feed-in. The same is true for increased interconnection capacity, which allows for increased flexibility by means of additional power exchange.

When interpreting these outcomes, it should be considered that the overall share of variable renewable energy does not increase as strongly as in the basic model. While the share of wind and solar power increases from 14% in 2013 to 34% in 2030 in the basic model (Germany only), these shares are lower in the extended model. In the whole region considered, i.e. Germany and its electric neighbours, the share of variable renewable energy sources grows from 8% in 2013 to 24% in 2030.

Supplementary Note 5. Discussion of limitations

General remarks

The model analysis requires a range of simplifying assumptions. For some of these, the direction in which results may be distorted is intuitive; for others, effects are less clear. To begin with, unit commitment models generally draw on stylized techno-economic parameters such as offtimes and start-up costs. These are hard to estimate bottom-up and may vary substantially between different block sizes, age classes, and manufacturers. Start-up fuel requirements in reality also depend on offtime duration, i.e. on plant temperature. Moreover, it is likely that the costs and restrictions related to thermal flexibility will change in the future. Yet how these factors may impact the respective unit commitment parameters—which are in any case stylized—and overall results is difficult to foresee.

To raise a more general point, some of the assumed technical constraints may not even exist in the real world. For example, the concept of minimum offtimes represents economic considerations (e.g. avoid unnecessary wear and tear) rather than physical realities. While unit commitment modellers who focus on the system perspective generally aim to represent such intricate and plant-specific economic considerations by means of simple parameters and restrictions, it is not straightforward to estimate the qualitative effects of such simplifications on model outcomes. Likewise, drawing on exogenous—although established and policy-relevant—future power plant portfolios inherently leads to distorted outcomes as the portfolio may in fact not resemble a long-term equilibrium. The NEP capacities used here may rather constitute a desirable development with respect to generation adequacy and system flexibility, but the actual realization of these capacities is uncertain. For example, lignite and hard coal plants may be phased out earlier because of emission concerns. In summer 2016, the German parliament passed the *Strommarktgesetz*, according to which eight existing lignite blocks are to be transferred into a new type of reserve between 2016 and 2019 and shut down permanently four years later. While this is already captured in the scenarios calculated here, similar measures may occur in the future. Accordingly, the shares of specific technologies and/or their flexibility characteristics may be either under- or overrated, with unclear consequences for start-up outcomes. In order to avoid these problems, using integrated investment and dispatch models would be desirable. Yet this requires alternative problem formulations in order to maintain computability.[14,15]

Factors contributing to an underestimation of start-up costs

Another simplification more specific to the analysis made here relates to the assumption that the flexibility of CHP generators does not change in future scenarios. In the real German situation, CHP flexibility should tend to increase by 2030, for example due to additional heat storage facilities. This may result in more flexible operation patterns, i.e. increasing start-ups of CHP plants.

Another factor that generally leads to an underestimation of cycling needs and related costs is the assumption that thermal efficiency does not decrease during part-load operation. If this were to be considered, shutting plants down completely instead of operating them in part-load mode would become more attractive.

Likewise, the hourly resolution used here underestimates sub-hourly renewable variability and related cycling requirements. An Irish case study shows that an increased temporal resolution leads to more realistic estimations of thermal cycling activities and related costs, and that increasing the temporal resolution from 60 to 5 minutes results in relative start-up cost increases of around 13%.[16]

Factors contributing to an overestimation of start-up costs

In contrast, other limitations may lead to an overestimation of start-ups and respective costs. A very important one is the assumption of fixed imports and exports in the 2020 and 2030 scenarios of the basic model. Reasons for making this simplification in the largest part of our analysis include substantial uncertainties with respect to the future development of neighbouring power systems as well as numerical challenges in solving pan-European unit commitment models. In general, power plants in neighbouring countries are unlikely to be less flexible than German ones. In addition, the shares of variable renewables in neighbouring countries are likely to be lower than in Germany in the medium run (Denmark being a noteworthy exception). Accordingly, we should underestimate the flexibility potentials in the European interconnection and overestimate start-up costs in Germany in the basic model.

In fact, the additional sensitivity "Endogenous cross-border exchange", which draws on an extended model version with a stylized representation of neighbouring countries, shows that future start-up costs in Germany may be lower than determined by the basic model. Yet our decomposition analysis indicates that results depend on the particular developments in neighbouring countries and the expansion of cross-border transmission capacities. In order to explore these factors in more detail, complementary analyses with a dedicated pan-European modelling approach would be useful.

Likewise, we tend to overestimate flexibility requirements in Germany because of linearly scaling up feed-in patterns of variable renewables. Although this is rather common in the literature, it neglects potential future smoothing of these profiles related to alternative generator designs and different geographic distributions.[10] The sensitivity "Smoother wind profiles" illustrates this effect.

Another potential overestimation of start-up costs is caused by considering only thermal power plants and pumped storage as the main suppliers of flexibility in the wholesale market. It is reasonable to assume that other types of power storage as well as demand-side flexibility potentials could increasingly play a role with larger shares of variable renewables.[3] Yet properly modelling load shifting would not only require detailed techno-economic input data on specific consumers, but also involves intricate model formulations which increase the computational burden.[17]

In case of non-spinning positive minute reserve provision by open-cycle gas (or oil) turbines, the model my also slightly overestimate start-up cost, as the costs of respective start-up costs $sc_i ST_{i,t}^{gt}$ are summed up for each hour individually. If a respective turbine provides non-spinning positive reserves in two subsequent hours, start-up costs incur for both periods. Yet such distortions should be small as this is rarely happening in the model, and overall start-up costs of gas turbines are nonetheless low compared to other technologies.

Further factors and unclear overall effect of distortions

A study that compares different model formulations shows that start-up cost outcomes hardly differ between deterministic and stochastic programs.[18] In a stochastic setting with an expected value approach, wind power forecast errors increase start-up costs by 1.5% compared to a deterministic case, while stochastic programming with a scenario tree reduces start-up costs by less than 2.0%. The reason for the latter is that the optimal number of thermal plants operating at least in part-load mode is higher than in a deterministic setting in order to be able to respond to uncertain short-term changes in power demand. Another study makes a similar point for stochastic wind power.[19] As we use a deterministic model, this may contribute to a slight upward distortion of start-up cost outcomes—yet effects in the opposite direction may also be conceivable.

Further, results depend on assumed fuel and CO_2 price developments. For instance, lower natural gas prices, which may for example be caused by increased shale gas exploitation, would generally lead to lower start-up costs. Assessing the effects of higher CO_2 prices would require further analyses, as this may change the dispatch merit order of lignite, hard coal and natural gas plants. Higher specific start-up costs than assumed here should lead to higher initial (and future) absolute levels, but relatively lower growth of overall start-up costs compared to those modelled here.

In our analysis, we abstract from network constraints. Regarding the German transmission grid, this assumption appears to be justified, as the scenarios are derived from the official Grid Development Plan (NEP), which assumes nearly perfect transmission expansion. As for distribution grids as well as cross-border exchange, which is fixed to historic hourly values, it is per se not clear how model outcomes are affected by this simplifying assumption. Deviations in both directions are conceivable, but these may heavily depend on specific distribution grid and cross-border congestion settings.

Summing up, a definitive assessment on the net effect of upward and downward distortions is not possible. The overall relevance of start-up costs may accordingly be either over- or underrated in this analysis. Yet we do not see any clear indication why the qualitative findings should change substantially if these limitations could be addressed.

Limitations of the extended model

The extended model version, which includes a stylized representation of neighbouring countries' power systems, necessarily comes along with additional limitations. For example, we may overestimate power system flexibility in the extended model, and accordingly under-estimate cycling requirements in Germany, because of modelling aggregate thermal generation capacity in neighbouring countries. Abstracting from balancing reserve constraints in neighbouring countries could have similar effects. With respect to hydro reservoir modelling, it is not clear if our simplified modelling approach leads to an over- or under-estimation of flexibility. The same is true for the assumption of constant and symmetric net transfer capacity values.[20,21] Actual import or export opportunities in particular hours may well be higher or lower. Likewise, it is not clear in which way flexibility outcomes are distorted by neglecting other countries than the direct electric German neighbours considered here. For example, an inclusion of the whole hydro-based Scandinavian region or Italy, combined with more detailed hydro reservoir modelling, may lead to different outcomes when it comes to system flexibility.

Negative prices

Finally, we briefly discuss the aspect of negative prices. Negative prices currently occur in bid-based real-world day-ahead or intraday power markets, and may become a more frequent phenomenon with growing shares of variable renewables. Negative prices may be thought to have an influence on start-ups and related costs in the sense that they provide additional signals to shut down generators in respective periods. In principle, we are unable to directly address negative prices with our mixed-integer cost-minimizing framework because of the solving process: first, the binary variables are solved and fixed, and subsequently the remaining linear program is solved. Accordingly, the marginals of the market clearing condition always reflect the marginal costs of the most expensive generator running in the respective period. These are always nonnegative, and prices thus cannot go below zero. One exception is penalized renewable curtailment, which we consider in the sensitivity discussed above. There, prices become negative in periods of curtailment at the level of the negative penalty.

In the real world, negative prices occur in day ahead or spot markets if energy-related renewable support schemes are present, or if power generators make respective energy bids, i.e. if the losses received in periods with negative prices are smaller than the costs of shutting down and subsequently starting the plants up again. In this case, negative prices are the result of efficient dispatch behaviour (or more precisely, efficient bidding). Further, negative prices may occur because of energy-based renewable support schemes.[22] Although we are unable to simulate such price formation with our model, we nonetheless determine the same unit commitment and dispatch as in a perfect decentralized bid-based market that is coordinated by prices. Outcomes with respect to start-up counts and costs accordingly do not differ. In this sense, negative prices could have distributional consequences, but would not change the short-run equilibrium.

Supplementary Tables

Supplementary Table 1: Sets, parameters, and variables

Sets	Description	Unit
$i \in I$	Set of thermal power plant blocks of various technologies	
$i^{gt} \in I$	Subset of open cycle gas turbines qualified to provide non-spinning positive minute reserve	
$j \in J$	Set of storage technologies	
$res \in RES$	Set of variable renewable power sources	
$rsrv \in RSRV$	Set of balancing reserves	
$rsrv^{up}, rsrv^{do} \in RSRV$	Subsets of positive and negative reserves	
$mr, sr \in RSRV$	Subsets of secondary and minute reserves	
$t, tt \in T$	Time set	Hours
Parameters		
$activ_{rsrv,t}$	Hourly share of reserves activated	[0,1]
$avail_t^{bio}$	Availability of biomass generation	[0,1]
$avail_{res,t}^{res}$	Availability of variable renewables	[0,1]
$avail_{i,t}^{th}$	Availability of thermal blocks	[0,1]
$cbex_t^{exog}$	Hourly cross-border exchange, i.e. German net exports (exogenous parameter)	MWh
dem_t^{whls}	Hourly power demand on the wholesale market	MWh
$dem_{rsrv,t}^{rsrv}$	Hourly reserve provision requirements	MW
$energy^{bio}$	Biomass energy budget	MWh
η_j^{in}	Storage loading efficiency	[0,1]
η_j^{out}	Storage discharging efficiency	[0,1]
$grad^{bio}$	Load gradient per minute of biomass power plants as a share of installed capacity	[0,1]
$grad_i^{th}$	Load gradient per minute of thermal blocks as a share of installed capacity	[0,1]
Λ	Capacity of largest gas turbine	MW
mc_i	Marginal generation costs of thermal blocks	€/MWh
$mstc_j^{in}$	Marginal costs of storage loading	€/MWh
$mstc_j^{out}$	Marginal costs of storage discharging	€/MWh
$othergen_t$	Other hourly power generation (hydro, waste)	MWh
$penalty_{res}$	Penalty for curtailment of variable renewables	€/MWh
$qmax^{bio}$	Generation capacity of biomass power plants	MW
$qmax_{res}^{res}$	Generation capacity of variable renewables	MW
$qmax_i^{th}$	Generation capacity of thermal blocks	MW
$qmin_i^{th}$	Minimum generation of thermal blocks	MW
sc_i	Start-up costs of thermal blocks	€
$stinmax_j$	Storage loading capacity	MW
$stime_i$	Start-up time of thermal blocks (minimum offtime)	Hours
$stlevmax_j$	Maximum storage level	MWh
$stoutmax_j$	Storage discharging capacity	MW

Binary variables		
$ST_{i,t}$	Start-up variable of thermal blocks (1 if block is started up in period t, 0 otherwise)	0 or 1
$ST_{i,t}^{gt}$	Start-up variable of gas turbines for non-spinning positive MR provision (1 if activated in period t, 0 otherwise)	0 or 1
$U_{i,t}^{th}$	Status variable of thermal blocks (1 if block is generating, 0 otherwise)	0 or 1
$U_{j,t}^{sto}$	Status variable of storage plants (1 if charging, 0 if discharging)	0 or 1
Free continuous variable		
$Cost$	Total dispatch costs	€
Positive continuous variables		
Bio_t	Hourly power generation from biomass	MWh
$Prov_{rsrv,t}^{bio}$	Hourly reserve provision by biomass power plants	MW
$Prov_{mr^{up},i,t}^{gt}$	Hourly provision of positive MR provision by non-spinning gas turbines	MW
$Prov_{rsrv,res,t}^{res}$	Hourly reserve provision by variable renewables	MW
$Prov_{rsrv,j,t}^{stin}$	Hourly reserve provision by storage loading	MW
$Prov_{rsrv,j,t}^{stout}$	Hourly reserve provision by storage discharging	MW
$Prov_{rsrv,i,t}^{th}$	Hourly reserve provision by conventional power plants	MW
$Q_{i,t}$	Hourly power generation by thermal blocks	MWh
$Rescurt_{res,t}$	Hourly curtailment of variable renewables	MWh
$Resint_{res,t}$	Hourly system integration of variable renewables	MWh
$Stin_{j,t}$	Hourly storage loading	MWh
$Stlev_{j,t}$	Hourly storage level	MWh
$Stout_{j,t}$	Hourly power generation from storage	MWh

Supplementary Table 2: Additional sets, parameters, and variables in the extended model with neighbouring countries

Sets	Description	Unit
$\boldsymbol{c \in C}$	Set of countries (including Germany)	
$\boldsymbol{dispnc \in DISPNC}$	Set of dispatchable technologies in neighbouring countries	
$\boldsymbol{jnc \in JNC}$	Set of storage technologies in neighbouring countries	
$\boldsymbol{l \in L}$	Links between countries	
$\boldsymbol{nc \in NC}$	Set of neighbouring countries (not including Germany)	
Parameters		
$\boldsymbol{avail^{res}_{res,t,nc}}$	Availability of variable renewables	[0,1]
$\boldsymbol{dem^{nc}_{t,nc}}$	Hourly power demand	MWh
$\boldsymbol{energy^{dispnc}_{dispnc,nc}}$	Energy budget of dispatchable technologies (only applies for hydro reservoirs and biomass)	MWh
$\boldsymbol{\eta^{in}_{jnc}}$	Storage loading efficiency	[0,1]
$\boldsymbol{\eta^{out}_{jnc}}$	Storage discharging efficiency	[0,1]
$\boldsymbol{inc_{l,c}}$	Incidence matrix of links and countries	-1, 0, +1
$\boldsymbol{mc_{dispnc}}$	Marginal generation costs of dispatchable technologies	€/MWh
$\boldsymbol{mc^{up}_{dispnc}}$	Marginal costs of upward load change	€/MWh
$\boldsymbol{mc^{do}_{dispnc}}$	Marginal costs of downward load change	€/MWh
$\boldsymbol{mstc^{in}_{jnc}}$	Marginal costs of storage loading	€/MWh
$\boldsymbol{mstc^{out}_{jnc}}$	Marginal costs of storage discharging	€/MWh
$\boldsymbol{ntc_{l}}$	Net transfer capacity of links	MW
$\boldsymbol{qmax^{dispnc}_{dispnc,nc}}$	Aggregate generation capacity of dispatchable technologies	MW
$\boldsymbol{qmax^{res}_{res,nc}}$	Aggregate generation capacity of variable renewable technologies	MW
$\boldsymbol{ror_{t,nc}}$	Hourly run-of-river generation in neighbouring countries	MWh
$\boldsymbol{stinmax_{jnc,nc}}$	Storage loading capacity	MW
$\boldsymbol{stlevmax_{jnc,nc}}$	Maximum storage level	MWh
$\boldsymbol{stoutmax_{jnc,nc}}$	Storage discharging capacity	MW
Binary variables		
$\boldsymbol{U^{sto}_{jnc,t,nc}}$	Status variable of storage plants (1 if charging, 0 if discharging)	0 or 1
Free continuous variables		
$\boldsymbol{Cbex^{endog}_{l,t}}$	Hourly cross-border exchange (endogenous variable)	MWh
Positive continuous variables		
$\boldsymbol{Qdisp_{dispnc,t,nc}}$	Hourly power generation by dispatchable technologies (including hydro reservoirs and biomass)	MWh
$\boldsymbol{Qdisp^{up}_{dispnc,t,nc}}$	Hourly upward load change of dispatchable technologies	MWh
$\boldsymbol{Qdisp^{do}_{dispnc,t,nc}}$	Hourly downward load change of dispatchable technologies	MWh
$\boldsymbol{Qres_{res,t,nc}}$	Hourly power generation by variable renewables	MWh
$\boldsymbol{Stin_{jnc,t,nc}}$	Hourly storage loading	MWh
$\boldsymbol{Stlev_{jnc,t,nc}}$	Hourly storage level	MWh
$\boldsymbol{Stout_{jnc,t,nc}}$	Hourly power generation from storage	MWh

Supplementary Table 3: Unit commitment parameters. Sources: DIW Berlin's database and ref. 5

	Minimum load (%)	Minimum offtime (hours)	Start-up fuel requirement for cold start (MWh_{th}/MW)	Start-up depreciation costs (€/MW)
Nuclear	50	10	16.7	50
Lignite / hard coal > 500 MW	40 / 38	8	5.9	49
Lignite / hard coal ≤ 500 MW	40 / 38	6	2.7	105
CCGT	45	2	2.8	60
Other steam turbines	38	2	2.8	57
Gas turbines	20	0	0.1	24

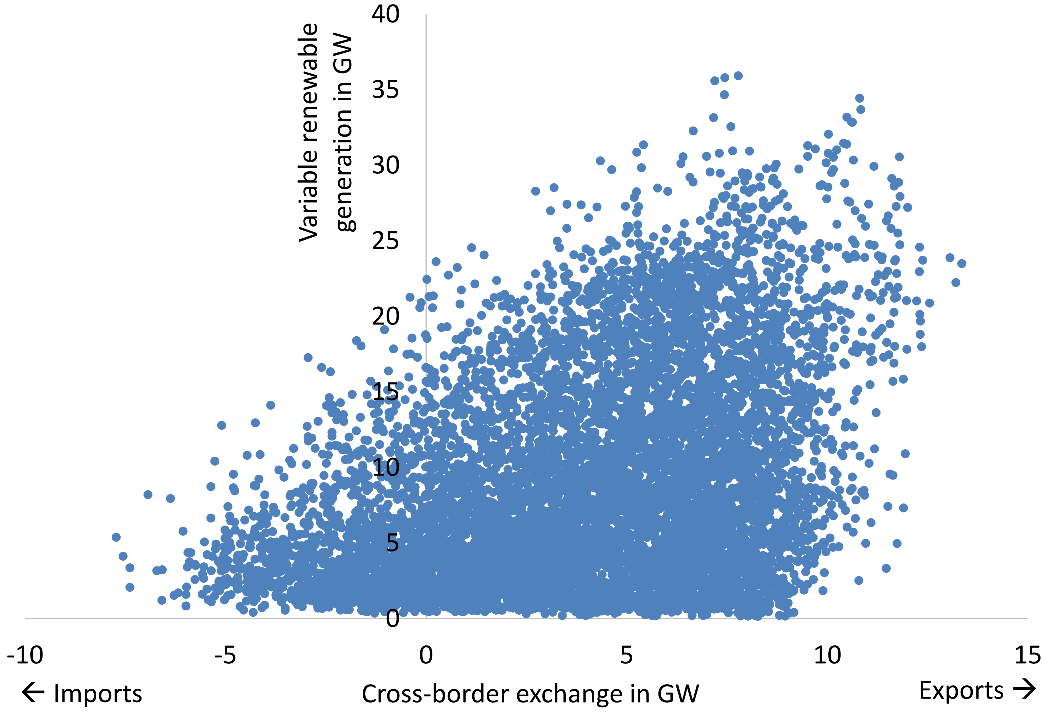
Supplementary Table 4: Marginal generation and load change costs in €/MWh

	mc_{dispnc}		mc^{up}_{dispnc}, mc^{do}_{dispnc}
	2013	**2030**	**2013 & 2030**
Nuclear	10.80	10.80	40
Lignite	10.55	31.04	60
Hard coal	34.04	49.71	60
CCGT	56.00	69.10	100
OCGT	80.00	95.01	30
Oil	167.72	192.64	40
Other thermal	49.04	63.21	50

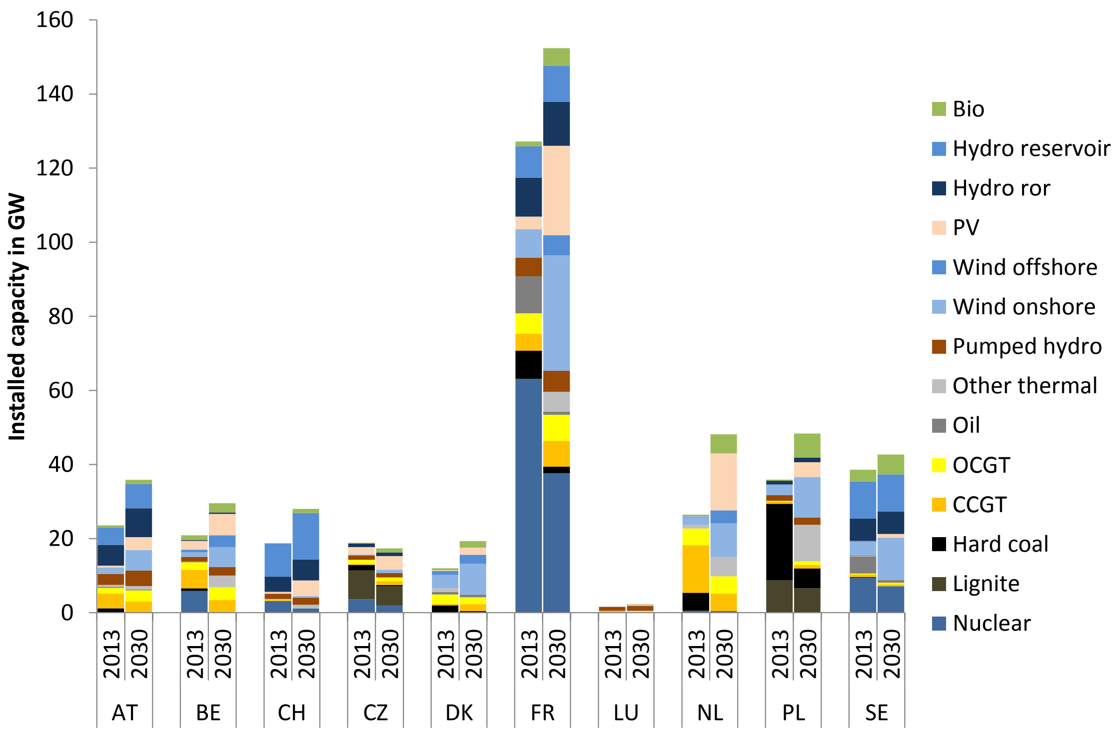
Supplementary Table 5: Incidence matrix for 21 country links (l) and 11 countries, and net transfer capacities (NTCs) for 2013 and 2030, derived from Entso-E (ref. 6)

	DE	AT	BE	CH	CZ	DK	FR	LU	NL	PL	SE	NTC in MW 2013	2030
l1	1	-1										1850	7500
l2	1		-1									0	1000
l3	1			-1								2865	3993
l4	1				-1							1500	2300
l5	1					-1						1796	4000
l6	1						-1					2925	4800
l7	1							-1				980	2300
l8	1								-1			3688	5000
l9	1									-1		1075	2500
l10	1										-1	603	1315
l11		1		-1								803	1700
l12		1			-1							750	1100
l13			1				-1					1500	3550
l14			1					-1				0	700
l15			1						-1			2325	2400
l16				1			-1					2100	2500
l17					1					-1		1325	550
l18						1			-1			0	700
l19						1					-1	1533	2210
l20							1	-1				0	190
l21										1	-1	300	600

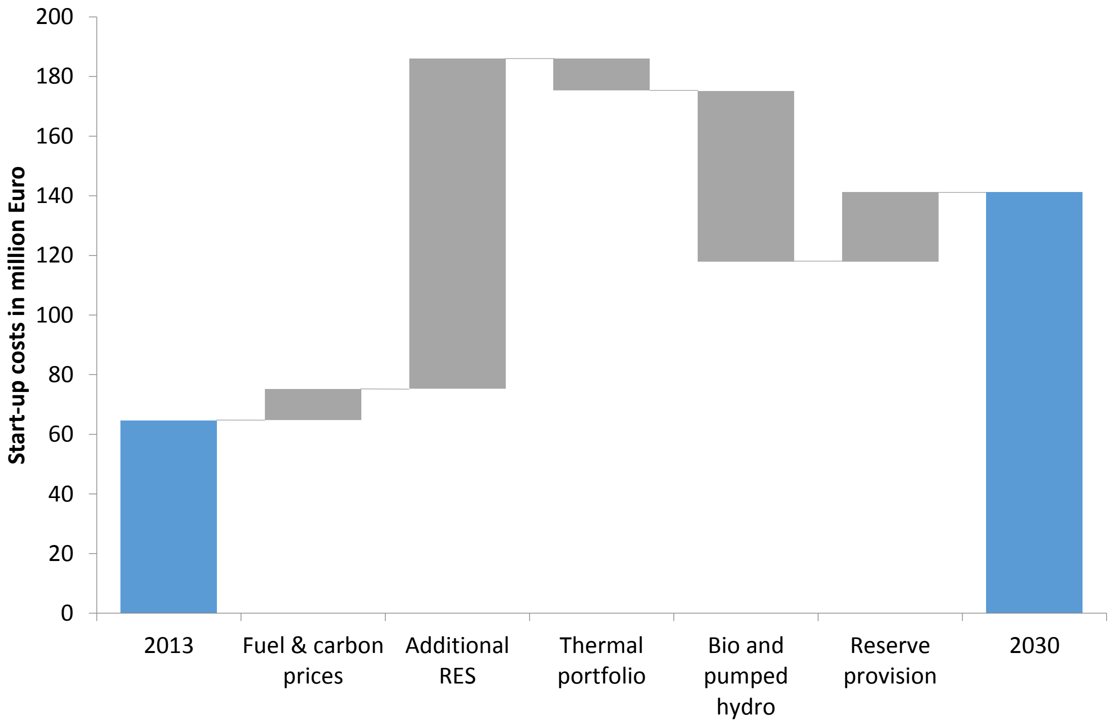
Supplementary Figures



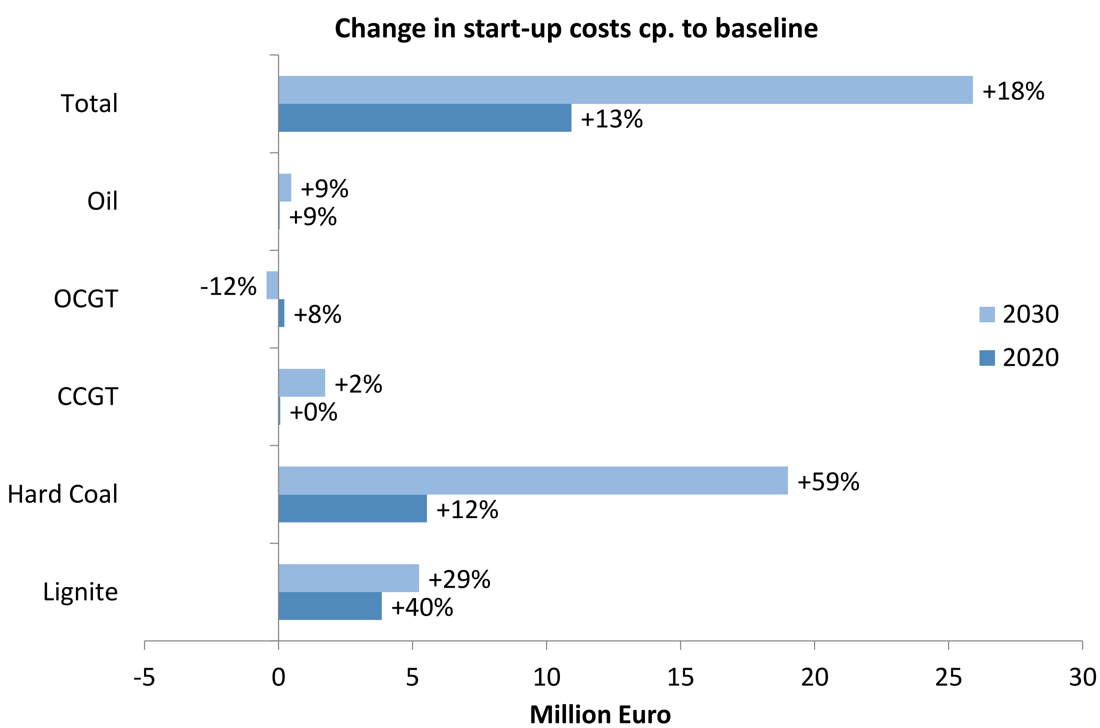
Supplementary Figure 1: Variable renewable power generation in Germany and cross-border exchange in 2013. There is a positive correlation of net exports and the feed-in of variable renewables.



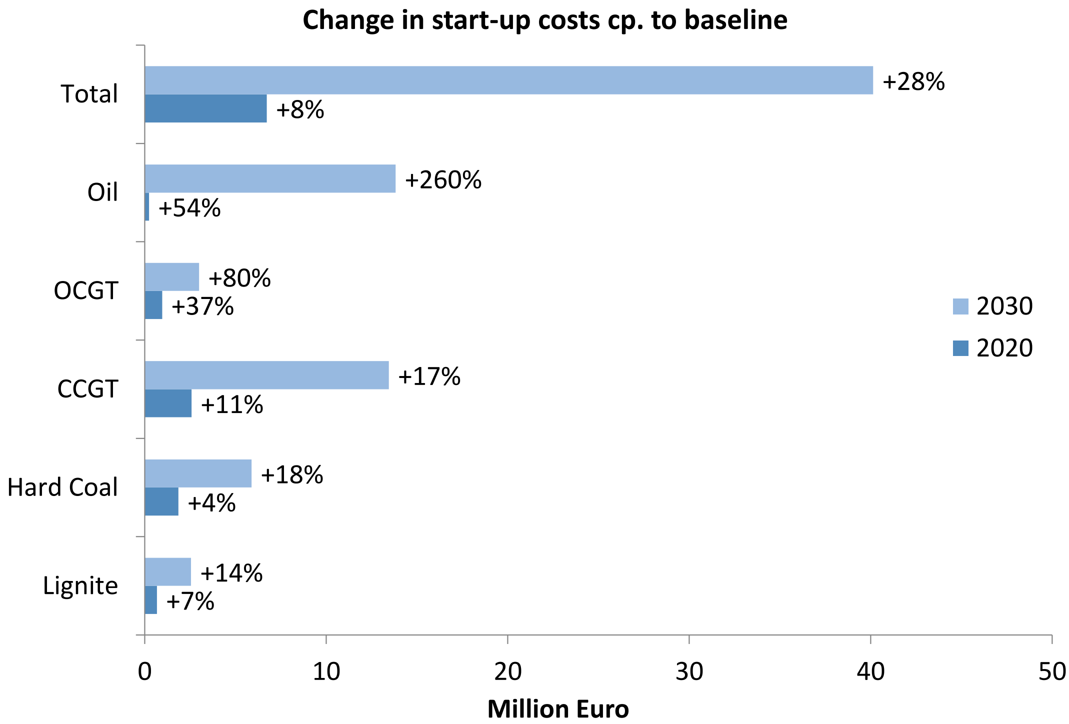
Supplementary Figure 2: Installed capacities in neighbouring countries (extended model). Data derived from Entso-E (ref. 6). Because of the deployment of variable renewables, installed capacity increases in all countries.



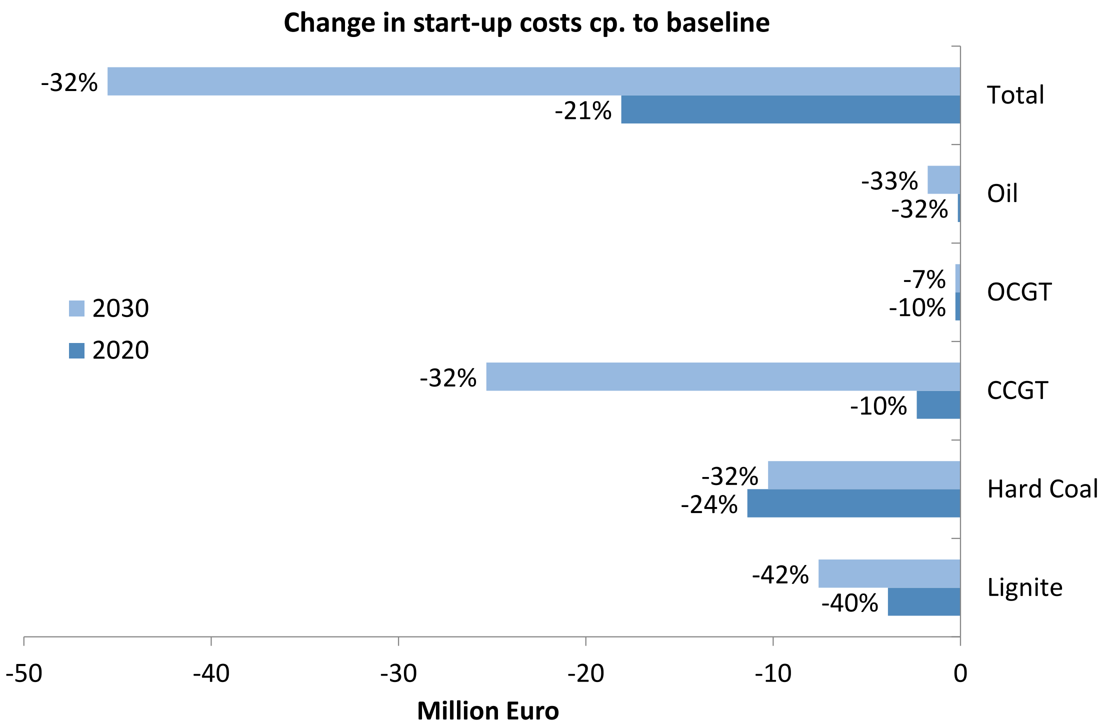
Supplementary Figure 3: Separation of effects between 2013 and 2030 baseline scenarios: start-up costs, alternative sequence. Renewable expansion has an even stronger positive effect on start-up costs as in the sequence presented in the main article.



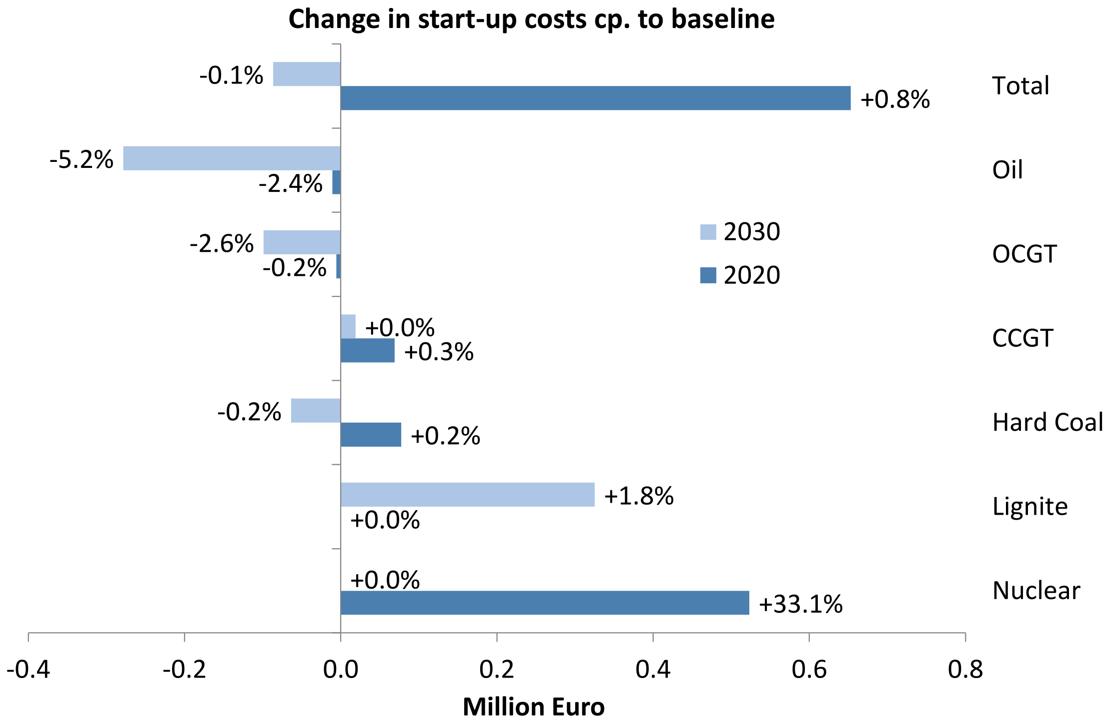
Supplementary Figure 4: "More RES": Absolute and relative change in yearly start-up costs compared to 2020 and 2030 baseline scenarios. A further expansion of variable renewables predominantly increases cycling needs of former base- and mid-load generators.



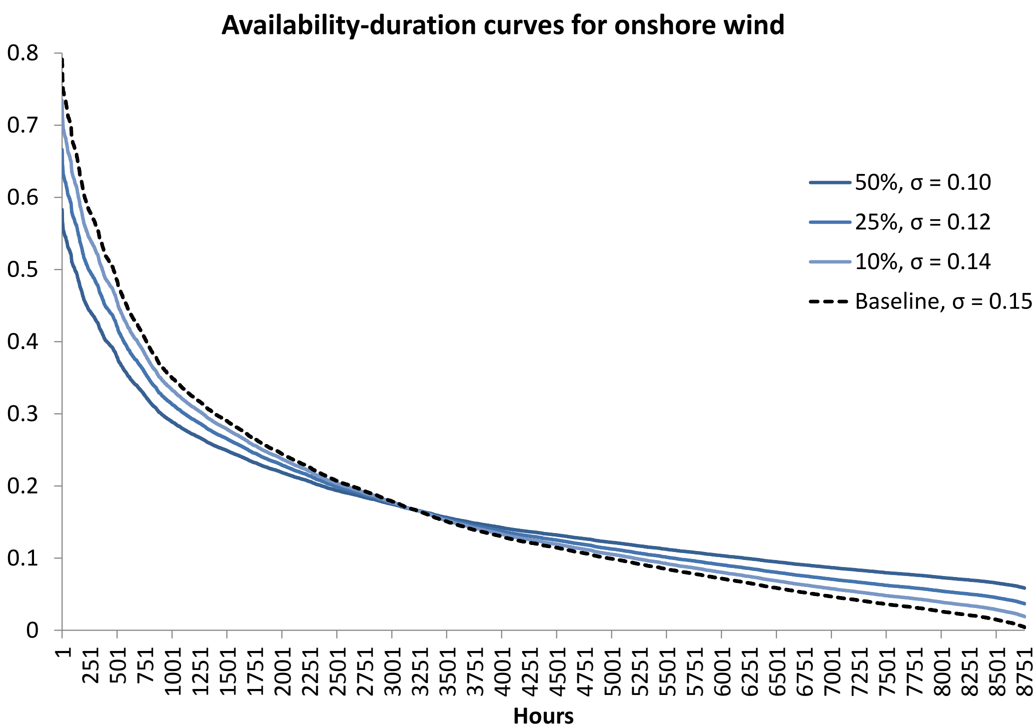
Supplementary Figure 5: "Less storage": Absolute and relative change in yearly start-up costs compared to 2020 and 2030 baseline scenarios. Flexible mid- and peak-load plants provide a substantial part of the flexibility that is provided by additional storage in the baseline.



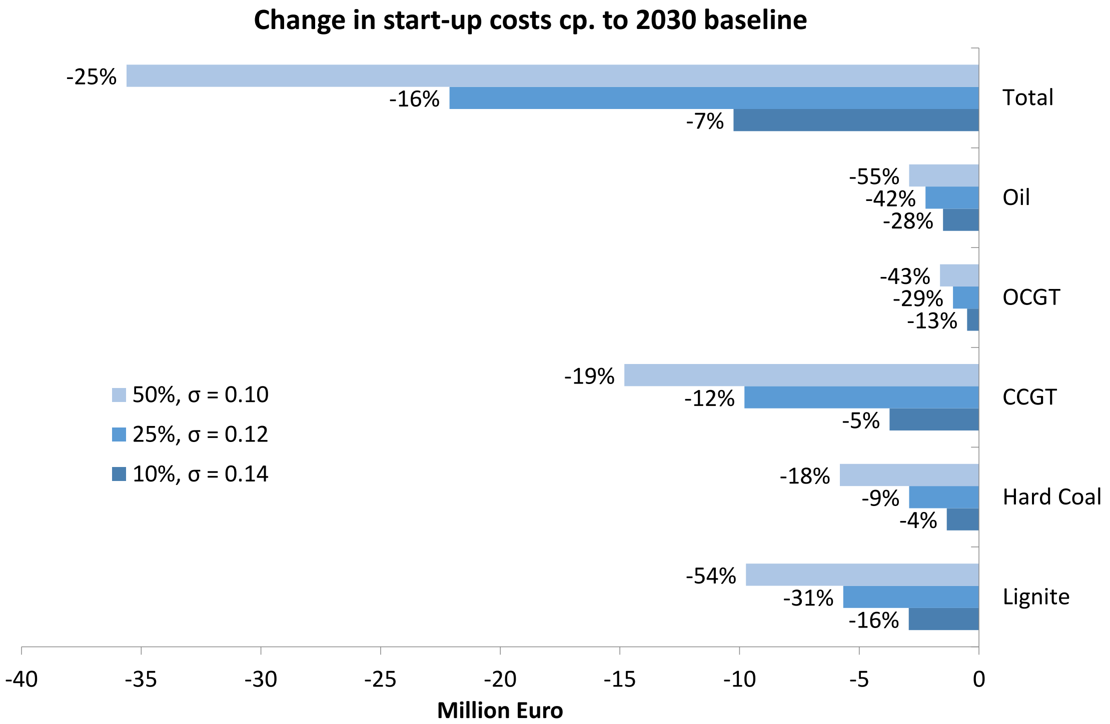
Supplementary Figure 6: "Lower minload": Absolute and relative change in yearly start-up costs compared to 2020 and 2030 baseline scenarios. Lower minimum load requirements would allow thermal plants to stay online during more hours of the year and would thus substantially decrease start-up costs.



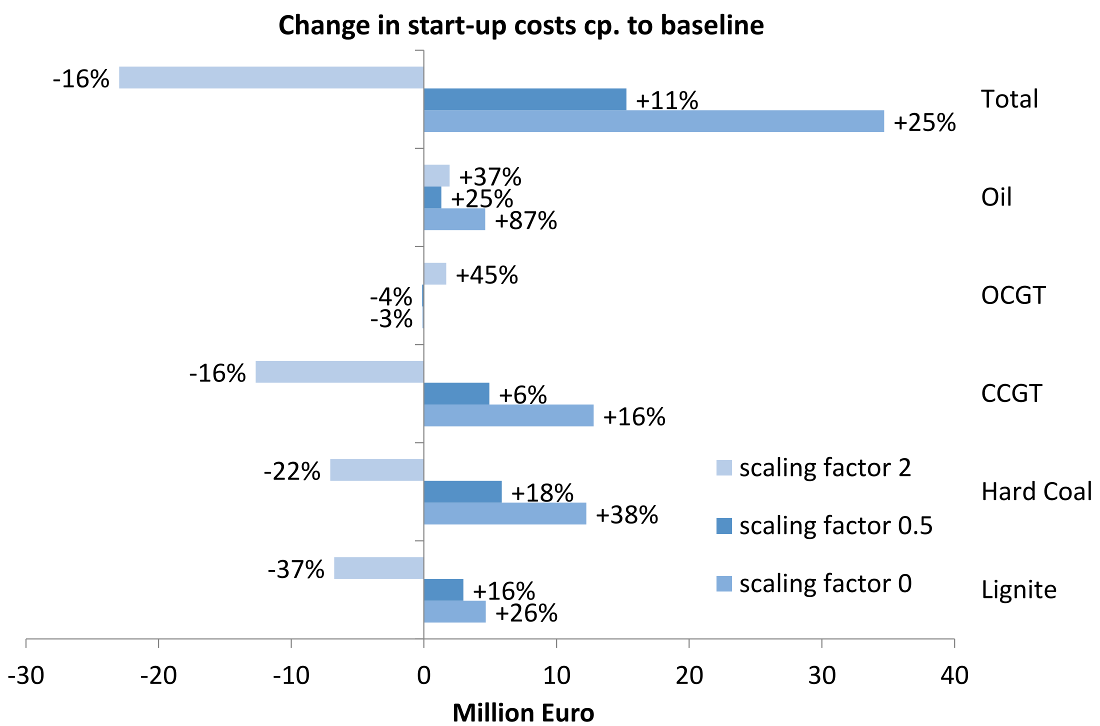
Supplementary Figure 7: "Less curtailment": Absolute and relative change in yearly start-up costs compared to 2020 and 2030 baseline scenarios. Overall effects are small compared to other sensitivities because renewable curtailment is low in the baseline.



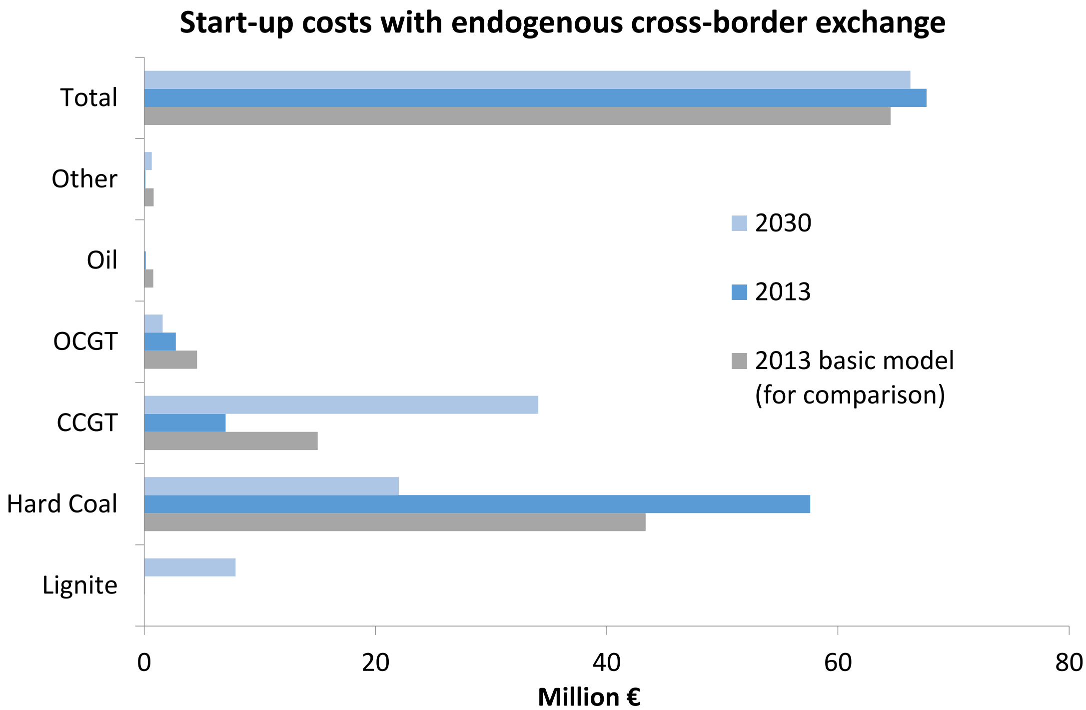
Supplementary Figure 8: Availability-duration curves for onshore wind power. We derive three synthetically smoothed profiles such that overall yearly energy delivered by onshore wind generators does not change.



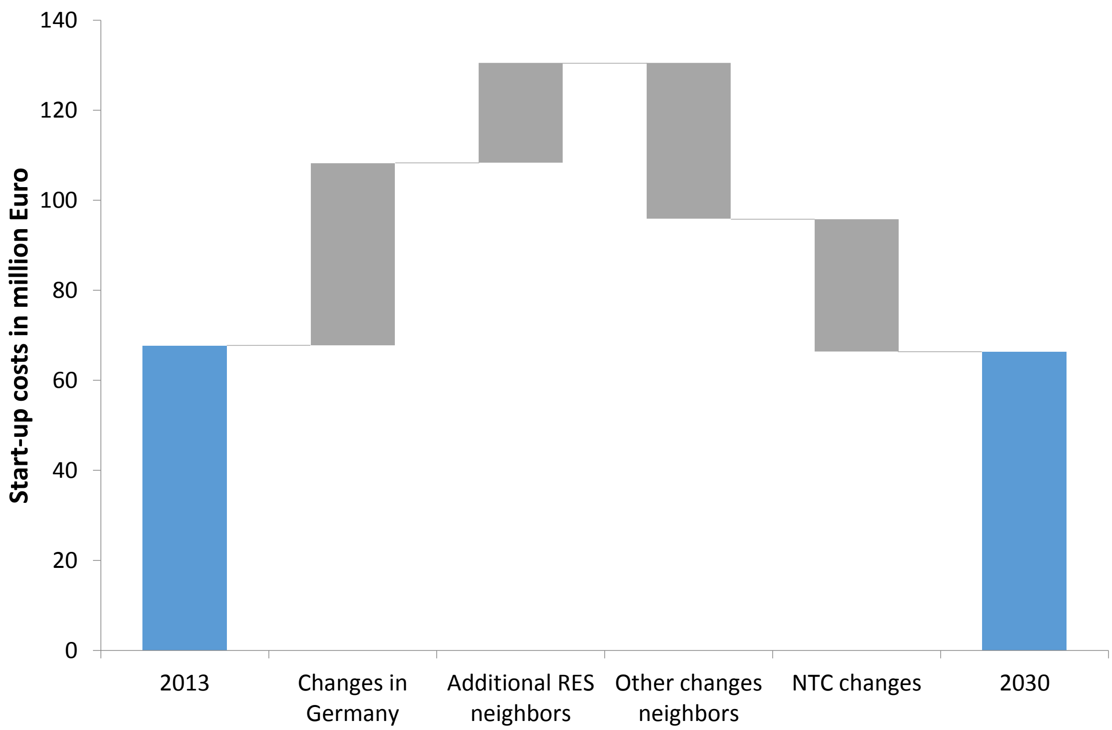
Supplementary Figure 9: "Smoother wind profiles": Absolute and relative change in yearly start-up costs compared to 2030 baseline scenario. Smoother wind profiles would reduce start-up costs.



Supplementary Figure 10: "Alternative exogenous cross-border exchange": Absolute and relative change in yearly start-up costs compared to 2030 baseline scenario. Higher (lower) cross-border exchange decreases (increases) start-up costs under the assumption that historic exchange patterns persists.



Supplementary Figure 11: Yearly start-up costs in the extended model. Start-up costs hardly change between 2013 and 2030, but their composition does.



Supplementary Figure 12: Separation of start-up cost effects between 2013 and 2030 scenarios in the extended model. Changes in Germany and the expansion of fluctuating RES in neighbouring countries would substantially increase start-up costs. Other portfolio changes in neighbour countries and increased NTCs have a counteracting effect.

Supplementary References

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