nature energy

ARTICLES

PUBLISHED: 3 APRIL 2017 | VOLUME: 2 | ARTICLE NUMBER: 17050

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

Wolf-Peter Schill[1]*, Michael Pahle[2] and Christian Gambardella[2]

The emerging literature on power markets with high shares of variable renewable energy sources suggests that the costs of more frequent start-ups of thermal power plants may become an increasing concern. Here we investigate how this develops in Germany, where the share of variable renewables is expected to grow from 14% in 2013 to 34% in 2030. We show that the overall number of start-ups grows by 81%, while respective costs increase by 119% in this period. Related to variable renewables' production, start-up costs increase by a mere €0.70 per additional megawatt hour. While the expansion of variable renewables alone would increase start-up costs, more flexible biomass power plants and additional power storage have counteracting effects. Yet changes in reserve provision and fuel prices increase start-up costs again. The relevance of start-up costs may grow further under continued renewable expansion, but could be mitigated by increasing system flexibility.

In many countries worldwide, the shares of variable renewable energy sources are steadily increasing. One of the countries at the forefront of this development is Germany, which aims to increase the share of renewables to at least 80% of gross power consumption by 2050[1]. Because of limited hydro, biomass and geothermal resources, which would allow for dispatchable renewable power generation, the expansion focuses on variable renewable sources such as wind and solar power. Accordingly, the net load of the German power system, which has to be served by thermal power plants, power storage and potentially flexible demand-side measures, will also become more variable[2]. In consequence, the operation of remaining thermal power plants has to change compared with former base- and mid-load cycling patterns[3].

Thermal plants are assumed to start up and shut down more frequently with increasing renewable supply variability. Before a thermal plant can feed electricity to the grid, it has to be started up, that is, ramped up at least to the minimum generation level. This usually comes at a cost independent of how much output is produced[4]. The size of these quasi-fixed costs, stemming from wear and tear as well as the fuel required to heat up the steam cycle, depends on the type and size of a particular plant. Anticipating that potentially growing costs from start-ups might become an increasing concern in the context of future variable renewable energy integration, we aim to analyse how important these costs actually may become, and which factors drive their development. This aspect has received only little attention in the otherwise burgeoning literature on renewable integration—possibly because so far start-up costs have been relatively small in size.

Different market jurisdictions have established different ways to secure remuneration for these costs by allowing complex bids. In centrally dispatched pool markets such as PJM in the US, nodal spot prices computed by independent system operators have to reflect start-up costs, for example by uplift or make-whole payments[5]. In contrast, most European power markets are generally self-dispatched and bilateral, implying the use of linear (non-discriminatory) pricing, where start-up costs of thermal power plants are reflected in block bids over several consecutive hours. Under certain circumstances, complex bidding can entail inefficient market clearing results[6–8]. Consequently, an increasing number of start-ups may not only incur additional system costs, but could also come along with an increased volume of complex bidding that could affect short-run allocative market efficiency.

Quantitative research on the future development of start-up costs is scarce so far. In general, it has been shown that the demand for power system flexibility increases with growing shares of variable renewables[9,10], and that this impacts the cycling needs of thermal power plants and respective costs[11,12]. Yet previous analyses are qualitative in nature[3], do not account for longer-term changes in the generation portfolio[13], or do not report specific start-up cost outcomes[12,14–16]. Only few quantitative studies explicitly focus on start-up costs in the context of renewable integration. An NREL (National Renewable Energy Laboratory) study on wind and solar integration in the Western Interconnection evaluates cycling cost impacts with a detailed modelling approach that addresses both variability and uncertainty of renewables[17]. In five scenarios of the year 2020 with shares of wind and solar power up to 33%, cycling costs increase by $US0.14 to 0.67 per megawatt hour of additional renewable generation. An analysis of distributed wind power integration in the New England market shows that cycling needs generally increase, but results depend on wind power forecast assumptions[18]. A corresponding study on solar power integration comes to similar conclusions[19].

Here we analyse the impact of increasing shares of variable renewables on the cycling of thermal plants with an open-source numerical optimization model. With respect to cycling, we consider only start-ups and neglect costs of further upward or downward ramping, as earlier analyses have shown that ramping costs are very small compared with start-up costs[17]. We model different scenarios of the German power system for the years 2013, 2020 and 2030, and separate the effects of increasing renewable capacities

[1]German Institute for Economic Research (DIW Berlin), Mohrenstr. 58, 10117 Berlin, Germany. [2]Potsdam Institute for Climate Impact Research (PIK), Telegrafenberg, 14473 Potsdam, Germany. *e-mail: wschill@diw.de

© 2017 Macmillan Publishers Limited, part of Springer Nature. All rights reserved.

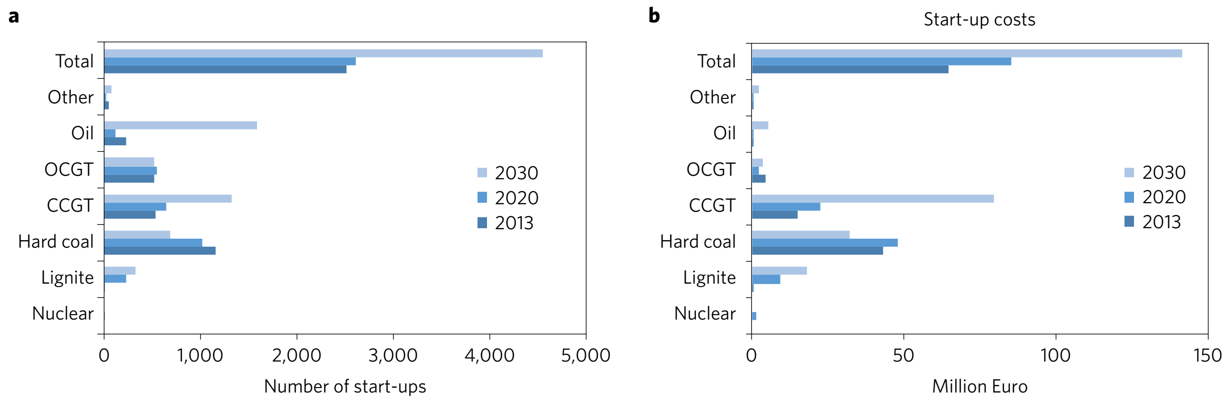

Figure 1 | Yearly numbers and costs of start-ups in baseline scenarios. a, Number of start-ups for different generation technologies. Overall start-ups of thermal power plants increase substantially between 2013 and 2030, driven by oil-fired and CCGT generators. They remain relatively low for lignite and even decline for hard coal plants. **b**, Start-up costs for different generation technologies. Start-up costs more than double between 2013 and 2030, largely driven by increasing costs of CCGT plants.

and other changes in the portfolio. We find that the overall yearly number of start-ups nearly doubles (+81%) and start-up costs more than double (+119%) between 2013 and 2030. This is driven by increasing shares of variable renewable energy sources, complementary changes of the remaining portfolio and growing fuel and carbon prices. Yet related to additional power generation by variable renewables, start-up costs increase by a mere €0.7 per additional megawatt hour of wind and solar power, and they remain low compared with total variable costs. The analysis also indicates that the relevance of start-up costs may increase further under continued growth of variable renewables beyond the levels modelled here, but could be mitigated by increasing system flexibility.

Numbers and costs of start-ups

We use an extended version of an existing unit commitment model[20] to simulate power system operations. The model minimizes total dispatch costs of the power plant fleet. Costs and restrictions related to starting up individual blocks of thermal power plants are represented with a mixed-integer formulation. The model has an hourly resolution and is solved for a full year. We apply the model to the German power system using scenarios of 2013, 2020 and 2030. We first define baseline scenarios for these years, where input parameters largely reflect the medium projections of the most recent German Grid Development Plan (in German *Netzentwicklungsplan*, NEP)[21].

While the share of variable renewables more than doubles between 2013 and 2030, the overall yearly number of start-ups of thermal power plants first increases only slightly from 2,508 in 2013 to 2,613 in 2020, and then grows to 4,544 in 2030, that is, +4% and +81% compared with 2013 (Fig. 1a). Yet the picture looks different for specific technologies. While the number of start-ups increases for lignite, combined-cycle gas turbines (CCGTs) and oil-fired plants, it stays roughly constant for open-cycle gas turbines (OCGTs) and decreases for hard coal plants.

These heterogeneous developments are driven by exogenous changes in the power plant portfolio. The NEP foresees a substantial capacity decrease of nuclear, hard coal and lignite plants between 2013 and 2030, combined with strongly increased capacities of variable renewables and CCGT plants. Because of larger supply variability due to increased renewable electricity generation, lignite plants cannot continue to run in a constant base-load mode in 2030 as was the case in 2013. Their full-load hours accordingly decrease by around 11%. Conversely, the operational pattern of hard coal plants on average changes from a mid-load position with regular daily cycles in 2013 to longer cycles in 2030. This is also driven by the fact that a larger share of the remaining hard coal fleet is operated in a flexibility-restricted combined heat and power mode in 2030. Average hard coal full-load hours accordingly increase by 9% while the number of start-ups decreases by 40%. CCGT plants have lower average full-load hours but higher overall production, and they also balance a substantial part of renewable variability in 2030. Their start-ups thus more than double (+145%). A particularly strong increase in start-ups can be observed for oil-fired plants. These peak-load generators, which have the smallest average block size of all technologies, are more frequently being used in the more volatile 2030 setting, particularly for the provision of positive (non-spinning) minute reserve. Their number of start-ups accordingly increases from 227 in 2013 to 1,590 in 2030.

While the overall number of start-ups increases by 81%, total yearly start-up costs grow more strongly from around €65 million in 2013 to €141 million (+119%) in 2030 (Fig. 1b). The growth in start-up costs is dominated by the shift toward CCGT plants (with increasing CCGT block sizes) and by fuel and carbon price increases assumed in the NEP. The latter are particularly pronounced for natural gas, translating directly into higher start-up costs. As opposed to the number of start-ups discussed above, start-up costs of oil-fired generators are negligible because of their small block sizes.

Relating this increase in start-up costs to additional power generation from variable renewables in the respective period (2013–2030) results in a value of €0.70 per additional megawatt hour of wind and solar power. To put this into perspective, values of $US0.14 to 0.67 per megawatt hour have been calculated for increasing the share of variable renewables from zero to 33% in the Western Interconnection[17]. The slightly higher values calculated here are related to higher fuel and carbon prices. It should also be noted that initial start-up costs are lower in our analysis, and the relative increase in start-up costs is thus higher compared with the US study.

Relating start-up costs to overall yearly variable costs of respective thermal generators shows that their relevance, on average, increases only slightly. This is because increasing fuel and carbon prices have an effect not only on start-up costs, but also on other variable generation costs. On average, the share of start-up costs grows from around 0.6% to 0.9% (Fig. 2). In relative terms, this appears to be a large increase, yet the overall share still remains on a low level. Accordingly, the assumed power system changes in the context of the German energy transition do not have a major impact on the relevance of start-up cost under baseline assumptions.

Yet there are again some differences between specific technologies. For lignite, the share increases from virtually zero in 2013 to 0.8% in 2030, and for CCGT plants from 0.7% to 1.2%. The relevance of start-up costs for the remaining hard coal plants

© 2017 Macmillan Publishers Limited, part of Springer Nature. All rights reserved.

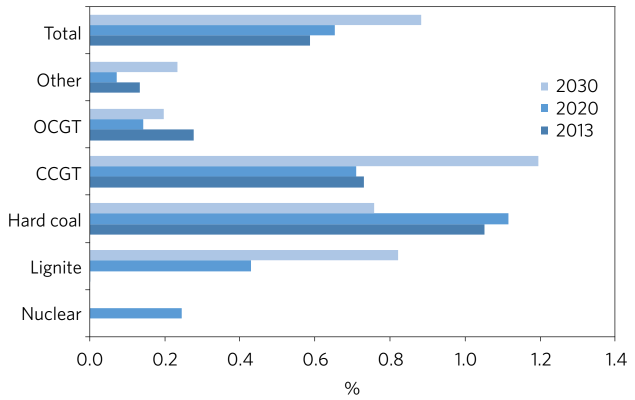

Figure 2 | Yearly start-up costs relative to yearly variable costs of main technologies. The relative relevance of start-up costs increases by 0.3 percentage points on average with the largest increase recorded for lignite (from virtually 0 cost in 2013 to 0.8% in 2030). Hard coal plants, on the contrary, experience a decrease in start-up costs.

conversely decreases from 1.1% to 0.8% because of the dispatch changes discussed above. Values for oil-fired generators are not shown in the figure, as their share of start-up costs in overall variable costs is much larger because of very low full-load hours. It decreases from around 94% in 2013 to 55% in 2030.

Results are driven by overlapping effects

An evaluation of additional model runs allows separating overlapping effects of the changing model inputs between 2013 and 2030. We start with the 2013 baseline scenario and first decompose the effects of additional variable renewables by increasing onshore and offshore wind power as well as photovoltaics capacities to 2030 levels, but holding all other input parameters constant at 2013 levels. Generation from biomass is then increased and flexibilized to 2030 assumptions in the next model run. In subsequent runs, assumptions on pumped storage, the thermal plant portfolio, the ability of renewables to provide reserves and finally fuel and carbon prices are successively changed to respective 2030 baseline levels.

Holding everything else constant, the expansion of variable renewables alone would increase the yearly number of start-ups by 1,543 (+62%, Fig. 3a). This result is intuitive given the exogenous growth in renewable variability, and it supports previous qualitative and quantitative findings in the literature[3,17]. Changes of two other assumptions, however, have countervailing effects. The assumed flexibilization of biomass power plants (in combination with a capacity expansion) and the increased pumped hydro capacity serve as additional flexibility options that together would offset most of the increase in cycling needs triggered by renewable expansion. The assumed changes in the thermal power plant portfolio, that is, the shift from nuclear, lignite and hard coal to CCGT plants, increase the number of required start-ups again. This is driven by differences in block sizes. While nuclear, lignite and hard coal plants have average block sizes of 1,339 MW, 465 MW and 316 MW in the 2013 portfolio, CCGT plants come with an average block size of only 304 MW in the 2030 scenario. Additionally assuming that renewables are eligible for the provision of balancing reserves—which is not the case in the 2013 baseline—slightly increases the number of start-ups further, as this enables a more flexible operation of some thermal generators (particularly hard coal) that were previously constrained by reserve provision. Changing fuel and carbon prices also have a small positive effect because they trigger additional non-spinning positive reserve provision by gas turbines.

Focusing on start-up costs instead of the number of start-ups, the separation shows a slightly different picture (Fig. 3b). While the effects of most parameter changes have the same direction as discussed above, the assumed change in the thermal portfolio now leads to a slight decrease of start-up costs—despite the above-mentioned increase in start-up counts. This is because decreasing block sizes matter for the number of start-ups, but not for respective costs. Instead, the shift from base-load plants to CCGT plants slightly decreases overall start-up costs because the latter have lower specific start-up costs. To mention another obvious difference between Fig. 3a and Fig. 3b, renewable expansion alone would more than double start-up costs (+114%). This increase is much larger than the corresponding effect on the number of start-ups because of strongly increased cycling of base-load plants that would incur relatively high costs under *ceteris paribus* (2013) assumptions. The share of start-up costs in overall yearly variable costs would grow to 1.6% in this setting. Growing fuel and carbon prices also have a relatively stronger positive effect, as they directly translate into higher start-up fuel costs. These effects sum up to an overall increase of start-up costs of +119%. This is nonetheless smaller than the respective growth in the share of variable renewable energy (+142%).

The separation of effects depends on the particular sequence of the decomposition analysis. Other sequences would also be possible. Supplementary Note 3 includes an alternative sequence that starts with fuel and carbon price changes, followed by changes in renewable capacity and the thermal portfolio. While the direction of effects is generally similar, the increase in start-up costs triggered by renewables alone would be even higher (+148%) compared with the sequence discussed above. Yet the share of start-up costs in overall yearly variable costs would still be lower than the one in the sequence discussed above.

Aside from more details on this alternative separation, the Supplementary Information contains additional material. This includes an analytical formulation of the model (Supplementary Note 1), a description of relevant input parameters (Supplementary Note 2), and sensitivity analyses with respect to alternative developments of renewable expansion, power storage, minimum load levels of thermal power plants, decreased renewable curtailment, smoother wind profiles, and exogenous cross-border exchange profiles (Supplementary Note 4). It also contains the description (Supplementary Note 1) and application (Supplementary Note 4) of an extended model that includes a stylized representation of neighbouring power systems and endogenous cross-border power exchange. Supplementary Note 5 concludes with a discussion of model limitations and their qualitative effects on results.

Conclusions

This study shows how start-ups of thermal power plants change in the context of a transition to larger shares of variable renewable energy sources. It complements and goes beyond previous work. For example, an analysis for the Irish system does not account for changes in the generation portfolio[13]. European analyses on thermal flexibility[12] and on the long-term effect of linear versus non-linear pricing rules[16] do not quantify specific start-up cost outcomes. The same is true for renewable integration analyses focusing on California[14] and western North America[15]. Only few quantitative studies explicitly focus on start-up costs in the context of longer-term renewable integration[17–19].

We contribute to this emerging literature with a dedicated quantitative analysis on the number and costs of start-ups in the changing German power system. Complementary to the US studies mentioned above, Germany provides a relevant international case study as a front-runner with respect to variable renewable deployment. Further, the German system is still heavily based on lignite and hard coal plants, as opposed to other systems with larger flexible gas or hydropower resources such as California[14]. We thus study the effects of renewable expansion in the context of a complementary transformation of the remaining power plant

© 2017 Macmillan Publishers Limited, part of Springer Nature. All rights reserved.

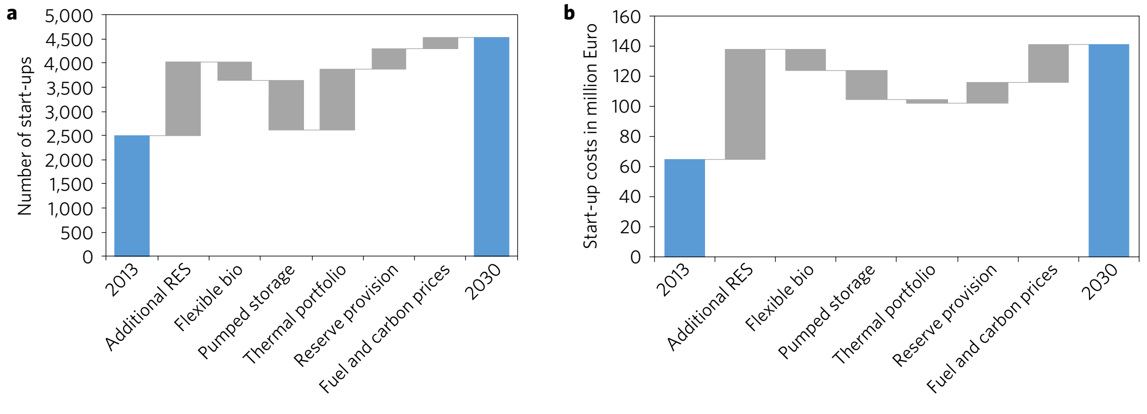

Figure 3 | Separation of effects between 2013 and 2030. a, Number of start-ups. Additional capacities of variable renewables and thermal portfolio changes substantially increase the number of start-ups, while additional pumped storage and flexible biomass have an opposite effect. **b**, Start-up costs. Renewable expansion alone would more than double start-up costs. Other factors, both negative and positive, roughly net themselves out.

portfolio. This includes a shift to more flexible plants and additional storage capacity. We also separate the effects of different portfolio changes to contrast other approaches in the literature that assume unchanged non-renewable portfolios[17–19].

Our analysis focuses on mid-term scenarios in which the share of variable renewables in Germany more than doubles from 14% in 2013 to 34% in 2030 (+142%). Under baseline assumptions, the overall number of yearly start-up procedures nearly doubles (+81%), whereas total start-up costs grow more strongly (+119%). The relative share of start-up costs in overall variable costs of thermal power plants increases from 0.6% to 0.9% and thus remains on a rather low level. Related to the growing power generation by variable renewables, start-up costs increase by €0.7 per additional megawatt hour of wind and solar power.

Several overlapping and partly countervailing effects drive these results. Isolating the effect of the expansion of variable renewables shows that this would increase start-up counts and costs to values similar to those mentioned above. Even then, start-up costs would remain at relatively low levels in absolute and relative terms and thus would be unlikely to cause major inefficiencies in the context of renewable integration. The effects of other future power system changes approximately compensate each other. Increased flexibility of biomass power plants and additional power storage capacities cause a reduction of start-up costs, whereas the assumption of renewables being able to provide reserves and growing fuel and carbon prices cause start-up costs to increase again.

While the overall relevance of start-up costs increases only moderately in the scenarios modelled here, this may change under alternative assumptions. This is also indicated by decomposition analyses and additional sensitivities (Supplementary Note 4). Start-up costs generally increase in the case of a stronger expansion of wind and solar power, lower power storage capacities, less flexible thermal power plants (including biomass) and lower cross-border exchange. In addition, our model addresses uncertainty of variable renewable feed-in not explicitly, but only implicitly by means of (deterministic) reserve provision and activation requirements. A full representation of stochastic renewable forecast errors may result in more significant impacts on start-ups. If volatility of wind and solar feed-in could be reduced, for example by a more system-friendly design of renewable plants or adjusted geographical distribution, start-up costs would not rise as much in the first place.

Our analysis may also be viewed in the context of the ongoing debate on the future design of power markets with large shares of variable renewables. On the one hand, baseline findings indicate that start-up costs do not gain central importance even if the share of variable renewables exceeds 30%. The volume of complex bids made by generators to ensure remuneration of their quasi-fixed costs in electricity auctions should thus not increase much, and market efficiency should not be significantly more affected—for instance, by paradoxically rejected blocks—than is currently the case. The transition to variable renewables would then also be unlikely to severely compromise the use of linear pricing in European power markets in the medium run.

On the other hand, under alternative assumptions, start-up costs may grow further both in absolute and relative terms. This could lead to situations in which non-convex costs of thermal power plants constitute more significant shares of total variable costs, which should then be properly addressed in future market designs. This may get increasingly important if the main options expected to provide future power system flexibility—flexible generators, storage, dispatchable renewables such as biomass, the demand side, and cross-border power exchange—developed less favourably than generally assumed, and if the shares of variable renewables increased far beyond the levels modelled here.

While the numerical analysis focuses on Germany, the transition to wind and solar power is not an exclusive German trend[22,23]. The International Energy Agency's 2016 World Energy Outlook projects global net capacity additions of wind power and photovoltaics of around 1.2 TW each between 2014 and 2040 in the 'New Policies' scenario[24]. In a scenario that is compatible with the 2 °C climate goal, capacity additions are even larger, such that wind power and photovoltaics together account for 27% of worldwide electricity generation in 2040. Our findings are thus also relevant for many other countries with thermal power systems that plan to undergo comparable transitions toward larger shares of variable renewable energy sources.

Methods

The optimization model. Exogenous model inputs include the generation portfolio, hourly load, which is assumed to be completely price-inelastic, hourly availability profiles of variable renewables, a yearly energy cap for biomass, reserve requirements and activations profiles, variable generation costs, start-up costs, minimum off-times and minimum load levels of thermal power plants. Endogenous model variables include the hourly unit commitment of all generation and storage capacities, hourly generation and reserve provision of all generators, and overall dispatch costs. The model is implemented as a mixed-integer linear program in the General Algebraic Modeling System and solved with the commercial solver CPLEX. Further information on the model is provided in Supplementary Note 1. The following paragraphs introduce the most important input parameters for baseline model runs. More details and alternative parameter assumptions for the sensitivities are provided in Supplementary Notes 2 and 4.

Generation capacity. Generation capacity is derived from the German Grid Development Plan (*Netzentwicklungsplan*, NEP). The NEP was drafted by German transmission operators and approved by the federal regulator after a series of public consultations[21]. As it serves as the basis for federal German grid

© 2017 Macmillan Publishers Limited, part of Springer Nature. All rights reserved.

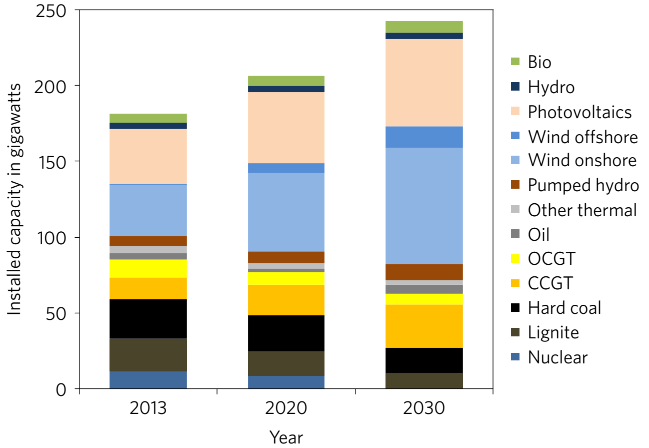

Figure 4 | Installed power generation capacities in Germany in baseline scenarios. Scenarios are derived from NEP (ref. 21). Variable renewable capacity increases substantially between 2013 and 2030, while lignite and hard coal capacity decreases, and nuclear is phased out completely. In 2020 (2030), onshore wind power reaches 51 GW (76 GW), offshore wind power 6 GW (15 GW) and photovoltaics 47 GW (57 GW). Nuclear capacity decreases from more than 12 GW in 2013 to less than 9 GW by 2020 and zero by 2030 because of the complete German nuclear phase-out by the end of 2022. Lignite and hard coal capacities decrease from 21 and 26 GW in 2013 to 11 and 16 GW in 2030, respectively. Natural gas-fired capacity conversely increases from 26 GW to 35 GW. The share of hard coal plants that operate in a combined heat and power (CHP) generation mode increases by 10% between 2013 and 2030, while the respective CHP share of CCGT plants decreases by 6%.

Table 1 | Fuel and carbon prices derived from NEP[21].

	Unit	2013	2020	2030
Lignite	€$_{2010}$ MWh$_{th}^{-1}$	1.5	1.5	1.5
Hard coal	€$_{2010}$ MWh$_{th}^{-1}$	9.6	10.0	10.3
Natural gas	€$_{2010}$ MWh$_{th}^{-1}$	27.0	29.9	32.8
Oil	€$_{2010}$ MWh$_{th}^{-1}$	54.0	56.0	60.4
CO_2 certificates	€$_{2010}$ t^{-1}	5.0	14.3	26.0

requirement legislation, it can be considered an official reference scenario, and is accordingly also used in many other studies. According to NEP, renewable capacity increases substantially by 2030 (Fig. 4), reflecting the German government's RES targets.

Fuel and carbon prices. Fuel and carbon price assumptions are also derived from NEP (Table 1). Renewables are assumed not to incur marginal costs. Yet in the case of biomass, there is a yearly energy cap, which implies a shadow price of biomass.

Time series data. Hourly profiles of variable renewables, load and power exchange with other countries are based on 2013 data, and power exchange is assumed not to change in the future in the baseline scenarios. Under these assumptions, the share of variable renewables (wind power and photovoltaics) increases from 14% (77 TWh) in 2013 to 24% (128 TWh) in 2020 and more than doubles (+142%) to 34% (187 TWh) in 2030. Including biomass and hydro power, the respective overall renewable shares are 27% in 2013 and 51% in 2030. These shares are defined as domestic renewable generation over domestic power consumption (excluding storage loading).

Data availability. The model code and all input parameters are available in Zenodo with the identifier http://dx.doi.org/10.5281/zenodo.259476[25]. The code is published under the MIT (Massachusetts Institute of Technology) open-source licence. Further, the data that support the plots within this paper and all other findings of this study are available from the corresponding author on reasonable request.

Received 5 February 2016; accepted 2 March 2017; published 3 April 2017

References

1. *Gesetz für den Ausbau erneuerbarer Energien* (Erneuerbare-Energien-Gesetz, 2017).
2. Schill, W.-P. Residual load, renewable surplus generation and storage requirements in Germany. *Energy Policy* **73,** 65–79 (2014).
3. Pérez-Arriaga, I. J. & Batlle, C. Impacts of intermittent renewables on electricity generation system operation. *Econ. Energy Environ. Policy* **1,** 3–18 (2012).
4. Stoft, S. *Power System Economics* Ch. 3–9 (IEEE, 2002).
5. Gribik, P. R., Hogan, W. W. & Pope, S. L. *Market-Clearing Electricity Prices and Energy Uplift* Harvard Working Paper (2007); https://www.hks.harvard.edu/fs/whogan/Gribik_Hogan_Pope_Price_Uplift_123107.pdf
6. O'Neill, R. P., Sotkiewicz, P. M., Hobbs, B. F., Rothkopf, M. H. & Stewart, W. R. Jr Efficient market-clearing prices in markets with nonconvexities. *Eur. J. Oper. Res.* **164,** 269–285 (2005).
7. Grimm, V., Ockenfels, A. & Zoettl, G. Strommarktdesign: Zur Ausgestaltung der Auktionsregeln an der EEX. *Z. Energ.* **32,** 147–161 (2008).
8. Meeus, L., Verhaegen, K. & Belmans, R. Block order restrictions in combinatorial electric energy auctions. *Eur. J. Oper. Res.* **196,** 1202–1206 (2009).
9. *The Power of Transformation. Wind, Sun and the Economics of Flexible Power Systems* (IEA, 2014); https://www.iea.org/publications/freepublications/publication/The_power_of_Transformation.pdf
10. Kondziella, H. & Bruckner, T. Flexibility requirements of renewable energy based electricity systems—a review of research results and methodologies. *Renew. Sustain. Energy Rev.* **53,** 10–22 (2016).
11. *Design and Operation of Power Systems with Large Amounts of Wind Power* IEA WIND Task 25 VTT Research Notes 2493 (VTT, 2009); http://www.vtt.fi/inf/pdf/tiedotteet/2009/T2493.pdf
12. Bertsch, J., Growitsch, C., Lorenczik, S. & Nagl, S. Flexibility in Europe's power sector—an additional requirement or an automatic complement? *Energy Econ.* **53,** 118–131 (2016).
13. Troy, N., Denny, E. & O'Malley, M. Base-load cycling on a system with significant wind penetration. *IEEE Trans. Power Syst.* **25,** 1088–1097 (2010).
14. Mills, A. & Wiser, R. *Changes in the Economic Value of Variable Generation at High Penetration Levels: A Pilot Case Study of California* LBNL-5445E (Ernest Orlando Lawrence Berkeley National Laboratory, 2012); https://emp.lbl.gov/sites/all/files/lbnl-5445e.pdf
15. Schlag, N. *et al. Western Interconnection Flexibility Assessment* Final Report (Energy and Environmental Economics, NREL, 2015); https://www.wecc.biz/Reliability/WECC_Flexibility_Assessment_Report_2016-01-11.pdf
16. Herrero, I., Rodilla, P. & Batlle, C. Electricity market-clearing prices and investment incentives: the role of pricing rules. *Energy Econ.* **47,** 42–51 (2015).
17. Lew, D. *et al. The Western Wind and Solar Integration Study Phase 2* Technical Report NREL/TP-5500-55588 (National Renewable Energy Laboratory, 2013); http://www.nrel.gov/docs/fy13osti/55588.pdf
18. Martínez-Anido, C. B. & Hodge, B.-M. *Impact of Utility-Scale Distributed Wind on Transmission-Level System Operations* Technical Report NREL/TP-5D00-61824 (National Renewable Energy Laboratory, 2014); http://www.nrel.gov/docs/fy14osti/61824.pdf
19. Martínez-Anido, C. B. *et al.* The value of day-ahead solar power forecasting improvement. *Sol. Energy* **129,** 192–203 (2016).
20. Schill, W.-P. & Gerbaulet, C. Power system impacts of electric vehicles in Germany: Charging with coal or renewables? *Appl. Energy* **156,** 185–196 (2015).
21. *Genehmigung des Szenariorahmens für die Netzentwicklungsplanung* Az.: 6.00.03.05/14-12-19/Szenariorahmen 2025 (Bundesnetzagentur, 2015); http://www.netzausbau.de/SharedDocs/Downloads/DE/2025/SR/Szenariorahmen_2025_Genehmigung.pdf
22. Milligan, M. *et al.* Alternatives no more: wind and solar power are mainstays of a clean, reliable, affordable grid. *IEEE Power Energy Mag.* **13,** 78–87 (2015).
23. Armstrong, R. C. *et al.* The frontiers of energy. *Nat. Energy* **1,** 15020 (2016).
24. *World Energy Outlook 2016* (International Energy Agency, 2016); http://dx.doi.org/10.1787/20725302
25. Schill, W.-P. *Start-up Costs of Thermal Power Plants in Markets with Increasing Shares of Variable Renewable Generation* (Zenodo, 2017); http://doi.org/10.5281/zenodo.259476

Acknowledgements

We thank J. Diekmann, P. Hanemann, C. Kemfert, F. Kunz, K. Neuhoff and O. Tietjen as well as the participants of the July 2015 Strommarkttreffen in Berlin and the Berlin Conference on Energy and Electricity Economics 2015 for valuable comments on earlier drafts. We further thank V. d. O. Campos for assistance concerning the sensitivity with endogenous cross-border exchange. Not least, we also thank Stiftung Mercator and Agora

© 2017 Macmillan Publishers Limited, part of Springer Nature. All rights reserved.

Energiewende for funding this research as part of the project 'A Renewable Energy Dominated Power Market: Challenges & Solutions for Market Design and Policy Instruments'. The views expressed here are our own.

Author contributions

All authors jointly developed the research design. W.-P.S. developed and calibrated the model, carried out the simulations, and processed the model outcomes. All authors contributed to writing the article.

Additional information

Supplementary information is available for this paper.

Reprints and permissions information is available at www.nature.com/reprints.

Correspondence and requests for materials should be addressed to W.-P.S.

How to cite this article: Schill, W-P., Pahle, M. & Gambardella, C. Start-up costs of thermal power plants in markets with increasing shares of variable renewable generation. *Nat. Energy* **2**, 17050 (2017).

Publisher's note: Springer Nature remains neutral with regard to jurisdictional claims in published maps and institutional affiliations.

Competing interests

The authors declare no competing financial interests.

© 2017 Macmillan Publishers Limited, part of Springer Nature. All rights reserved.