Facilitating variable generation of renewables by conventional power plant cycling: costs and benefits

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***Abstract*—Renewable electricity generation from wind and sun is variable, meaning that it fluctuates in time in a largely uncontrollable way. The variable character of wind and sun requires operational flexibility in the power system. An important source of operational flexibility is conventional power plant cycling, i.e., changing the power output of conventional units by means of ramping and switching (starting up and shutting down). This paper assesses the impact, limitations and costs of facilitating variable generation from wind and sun with conventional power plant cycling, based on a case study of the German 2013 power system. The results presented in this paper follow from a detailed unit commitment model. The study shows that, under the assumptions made, conventional cycling is able to deal with variable wind and solar generation. Cycling costs rise with increasing wind and solar generation but are outweighed by the decline in fuel and CO_2 emission costs.**

***Keywords*—Variable generation, wind power, solar power, conventional power plant cycling.**

I. Introduction

WIND and sun are intermittent power sources, meaning that their generation is - to a certain extent - unpredictable, variable and not or in a limited way dispatchable (e.g., wind turbines can be curtailed, reducing their output). Power generation form wind and sun has important implications on the required level of system flexibility. System flexibility can be defined as the amount of reserves and the rate at which these reserves can be deployed. Flexibility is needed to cope with contingencies and maintain the supply-demand balance [1]. Flexibility in the power system can be split up, according to its time horizon, in capacity reserves, operational reserves, and balancing reserves. Capacity reserves come into play considering the supply-demand balance in the longer run on an aggregated basis and relate to the question whether investments in new capacity are needed. Operational reserves are used by market players to maintain the supply-demand balance of their portfolio on hourly or quarter-hourly basis. Balancing reserves can be used by the transmission system operator to maintain supply-demand balance in its control area on (almost) instantaneous basis. This paper deals with operational flexibility in the power system.

Five different sources of operational reserves exist; cycling of conventional power plants, curtailment of renewable generation, storage, demand side management and cross-border transmission. Cycling is defined as changing the output of a power plant by starting up, shutting down, ramping up or ramping down [2],[3]. System flexibility has a technical aspect but also a market aspect, meaning that a market mechanism has to be in place to make the flexibility accessible to market participants at the correct price. In this study, it is assumed that all – technical feasible – operational flexibility is available to the market.

This paper deals with cycling of conventional power plants as operational flexibility source to cope with the variability of renewable power sources. Lively literature exists on the link between renewable injections and operational flexibility. A first series of papers considers the variable character of renewables. Hirth [4] stresses the importance of variability when assessing the impact of renewables on the power system. Holtinnen [5] investigated the variability of wind generation in the Nordic Countries and estimated that reserve requirements have to increase with 1.5% to 4% of installed wind capacity. Huang *et al.* [6] investigate the flexibility of storage and cycling to cope with the variability of wind and sun. It is shown that storage reduces the need for conventional cycling. Van den Bergh *et al.* [7] show how conventional power plant cycling changes due to renewable injections. Renewables cause a shift from start-stop flexibility at low amount of renewables to ramping of base load units at high amount of renewables. A second series of papers considers both the variable and partly unpredictable character of renewables. Ummels *et al.* [8] simulate the effect of wind power on the operation of the Dutch thermal generation portfolio. The study stresses the importance of renewables curtailment to prevent minimum load problems. Troy *et al.* [9] examine the effect of significant wind penetration on base-load cycling in the 2020 Irish system. It is shown that the operation of steam power plants and combined cycle plants is heavily affected by wind penetration. They also show that increasing start-up costs tend to reduce start-stop cycling at the cost of more part-load operation and ramping. In another paper, Troy *et al.* [10] address the issue that not all cycling costs are taken into account in the bidding mechanisms. They conclude that modeling cycling costs considerably impacts the unit commitment and economic dispatch. Thuoy *et al.* [11] discuss the impact of unpredictable wind output on power generation and system costs. In this respect, Thuoy compares the performance of a stochastic and deterministic unit commitment model.

This paper addresses the technical limitations and the costs of facilitating variable generation from wind and sun with conventional cycling. To this end, the 2013 German power system is investigated as a case study. The operation of the same set of power plants is investigated for a case with high dynamic cycling parameters assigned to the power plants and a case with low dynamic cycling parameters assigned to the power plants, in order to study the effect of the power system flexibility on renewables integration. In addition, the cost benefits of wind and sun are discussed in detail, taking account of all cost savings (e.g., fossil fuel cost savings) and all cost increases (e.g., cycling costs, part load operation costs). The added value of this study to the existing literature lies in its focus on the limits of conventional cycling and its detailed cost discussion. The existing literature considers moderate levels of wind and solar generation, in line with historical generation levels. This paper looks at high levels of renewables, up to 50% wind and sun, and discusses all related operational costs and costs saving As such, this study contributes to ongoing discussions on compatibility between variable generation of renewables and conventional power generation [12],[13].

This paper considers conventional cycling as the only source of flexibility in the power system and assumes fully predictability of the renewable generation. These two assumptions should be kept in mind when interpreting the results presented in this paper.

Section II discusses the variability of wind and solar generation, followed by an overview of the technical and cost-related aspects of conventional power plant cycling in section III. Section IV presents the 2013 German power system as case study and describes the unit commitment model used in this paper. Section V presents the results and discussions. Section VI concludes.

II. Variability of Renewables

In the German 2013 power system, wind energy fulfilled 10.1% of final electricity demand and solar energy 6.4%. Often statistical parameters like the standard deviation are used to describe the variability of renewable generation [5]. The average 2013 German wind generation was 5.4 GW with a quarter-hourly standard deviation of 4.9 GW (31.3 GW installed). The average solar generation was 3.4 GW with a quarter-hourly standard deviation of 5.4 GW (32.4 GW installed). However, statistical parameters do not take account of the sequence in which the generation data occur and are therefore not the best measure of variability. To illustrate this, consider two sinusoidal wind generation profiles with different frequency but identical mean and standard deviation. These two wind profiles have a different impact on the power system. The low frequency wind profile contains fewer variations and slow flexibility sources might be able to cope with the variable wind profile. The high frequency wind profile fluctuates more and requires fast flexibility sources. In this paper, the variability of renewables is expressed as:

$$v_t = \frac{|g_{t+1} - g_t|}{T} \quad (1)$$

with g_t the average renewable generation during time step t, T the number of minutes per time step and v_t the variability at time step t expressed in [MW/min]. In the remainder of the paper, variability is calculated as defined in equation (1).

TABLE I
VARIABILITY IN GERMANY 2013 WIND AND SOLAR GENERATION [14]-[19]

	Capacity [GW]	Average variability [MW/min] quarter-hourly	hourly	daily
Wind	31.3	8.6	6.2	1.9
Sun	32.4	15.5	15.2	0.6
Wind & sun	63.7	20.6	18.8	1.1

The variability in renewable generation depends on the considered time frame. On a quarter-hourly basis more fluctuations are seen than on an hourly basis. Analogously, the variability depends on the level of aggregation. The variability in aggregated output of several wind turbines is likely smaller than the output variability of one wind turbine, relatively speaking. To illustrate this, Table I shows the average variability in renewable generation for different time frames.

The figures of Table I indicate the importance of the time frame. The shorter the time frame, the more distinct the variable character of wind and solar generation. The appropriate time frame to evaluate wind and solar variability depends on the time constant of the considered flexibility source. For low dynamic flexibility sources a daily time frame might be appropriate. For high dynamic flexibility sources a quarter-hourly time frame might be more appropriate. From the point of view of the system operator, responsible for maintaining the grid frequency, the relevant time frame is minutes and shorter. In this study, a quarter-hourly time frame is used as this is an often used time frame for market clearing.

The variability of renewables translates into a changing variability of the residual load (i.e., original electricity demand minus wind and solar generation). The variability in the residual load can be measured the same way as the variability in renewable generation (see equation (1)). Fig. 1 shows the average variability in residual load for the 2013 German system as function of wind and solar generation (expressed as share of electricity demand). If all renewable generation comes from wind, the change in variability is rather modest. On the other hand, if all renewable generation comes from sun, the variability in residual load rises sharply at high renewables injections. If wind and sun contribute together to the renewables share (at the 2013 historical ratio of 1.58 units of wind energy for every unit of solar energy), the variability increases as well, but much less dramatic than in the solar-only case. Recall that the 2013 wind and solar share is 16.5%. Hence at current levels of renewable generation there is a moderate increase in variability of residual load due to wind and solar generation.

As shown in Fig. 1, renewable injections can also decrease the variability in residual load. At moderate renewable injections, the midday peak in electricity demand is smoothed out, mainly by solar generation, reducing the variability in the residual load. At higher renewable injections, residual load shows a dip in the middle of the day, increasing the variability of residual load again. One can conclude that the variability in residual load first decreases with increasing renewable injections, to rise afterwards.

Renewable injections do not only change the variability in residual load, they also lower the average residual load. This implies that the intersection of the (inelastic) load with the merit order shifts to the left, i.e., towards base load plants (see the merit order of Fig. 2). The power plants on the margin are the ones that cycle. Renewable injections hence also affect the type of power plants that cycle.

In summary of this section, renewable injections from wind and sun change, in the framework of this paper, (1) the variability of the residual load and (2) the magnitude of the residual load. The first effect impacts the amount of cycling and the second effect the type of power plants that cycle. To reflect all four combinations of these two effects, four different weeks will be considered in detail in the remainder of this paper (see Table II).

TABLE II
WEEKS CONSIDERED IN DETAIL (2013)

Residual load	Low variability	High variability
Low demand	May 27-June 2 (week 22)	April 22-28 (week 17)
High demand	Oct 28-Nov 3 (week 44)	Sept 9-15 (week 37)

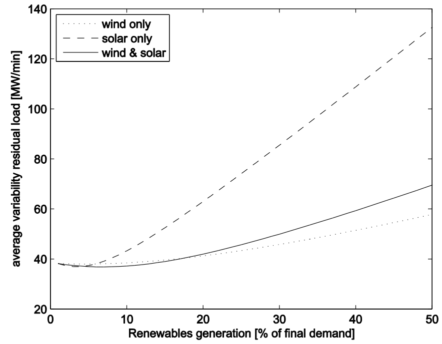


Fig. 1. The variability in residual load raises with increasing renewable injections (yearly average variability, Germany 2013, quarter-hourly basis).

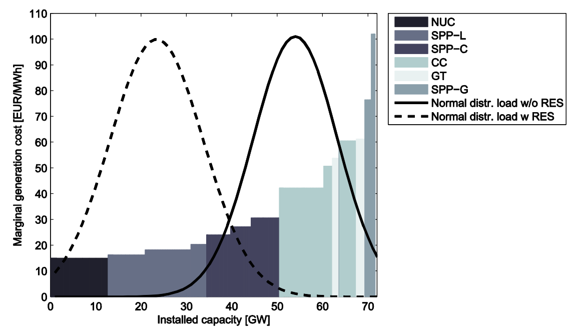


Fig. 2. Renewable generation shifts the residual load towards base load plants (Germany 2013, normalized Gaussian distribution of load time series, 23% renewables share in load series with renewables, NUC: nuclear units, SPP-L: lignite fired steam power plants, SPP-C: coal fired steam power plants, CC: combined cycle units, GT: gas turbines, SPP-G: gas fired steam power plants).

III. Cycling of Conventional Units

Cycling of conventional units is an important source of operational flexibility in the power system. The following types of power plants are referred to as conventional units within the scope of this study; nuclear units (NUC), coal fired steam power plants (SPP-C), lignite fired steam power plants (SPP-L), gas fired steam power plants (SPP-G), combined cycle units (CC) and open-cycle gas turbines (GT).

Cycling has a degenerating effect on units. When a generation unit varies its output, components in the unit are subject to stresses and strains. During the shutdown of a unit, components undergo large temperature and pressure stresses [20]. These stresses and strains lead to accelerated component failures and forced outages [21]. Starting up a unit is even more demanding. Wear and tear on the components of the generation units is exacerbated by a phenomenon known as creep-fatigue interaction [20].

The cost associated with power plant cycling consists of several components. Kumar *et al.* [22] mention 5 distinct groups of cycling costs:

(1) the cost for fuel, CO_2 emissions and auxiliary services during start-up, further referred to as direct start cost;
(2) the capital replacement costs and maintenance cost due to start-ups, further referred to as indirect start cost;
(3) the cost of forced outages due to cycling, which is the opportunity cost of not generating during an outage, further referred to as forced outage cost;
(4) the capital and maintenance cost related to load following, further referred to as ramping cost;
(5) the cost of a decrease in rated efficiency due to cycling, further referred to as efficiency cost.

The total cost of cycling is not always well understood. Operators might underestimate total cycling costs and only take the fuel and CO_2 emission cost of a start-up (direct start cost) into account when making the unit commitment decision, although this cost is quite small compared to the total cycling cost [21]. Cycling costs depend on many factors like the type and age of the power plant. Therefore it is difficult to put one number on the cycling costs of conventional power plants. According to Lefton *et al.* [21], it is estimated that cycling costs of conventional fossil-fuel fired power plants can range from US$ 2,500 to US$ 500,000 per single on/off cycle, depending on the type of the unit, age, usage pattern, etc. Kumar *et al.* [22] report cycling costs - in US$ per cycle - with a factor 100 difference between the lowest and highest cycling cost. A study of the DIW Berlin on the costs of electricity generation also reports such a wide range of cycling costs [23].

Technical limitations constrain the cycling of conventional power plants. A power plant operates between a minimum and maximum power output and its ramping is constrained by ramping limits. A third dynamic constraint is about the minimum up and down times. In the literature a wide range of cycling parameters, used in generation scheduling models, can be found. Table III gives an overview of outer limits of cycling parameters. A cycling parameter can reflect a hard-technical constraint (e.g., a minimum down time is needed to synchronize a generator to the grid frequency) or a more cost related constraint (e.g., an operator might impose minimum up times to reduce the cost of startups and shutdowns) [23]. Thus the cycling parameters allocated to power plants might only reflect the technical limits of the power plant or could also include cost related considerations.

In this paper, simulations are run for a low dynamic power plant portfolio and for a high dynamic power plant portfolio. Both portfolios contain the same set of power plants, i.e., the 2013 German portfolio, but with different cycling parameters. In the low dynamic portfolio, the power plants have stringent parameters (see Table III, upper bound of minimum load factors, lower bound of ramping gradients and upper bound of minimum up and down times). In the high dynamic portfolio, less constraining parameters are assigned to the same set of power plants (see Table III, lower bound of minimum load factor, upper bound of ramping gradients and lower bound of minimum up and down times). The difference between the low and high dynamic portfolio can be interpreted as a difference in technical characteristics of the power portfolio or as a difference in the way the portfolio is operated (e.g., stringent limitations reflect a more conservative mode of operation). In both portfolios, the operators face the same production and cycling costs.

Conventional power plant cycling is closely related to part load operation. Operating a power plant at less than its rated power output goes together with a decrease in operating efficiency. Fig. 3 shows typical part load efficiency curves used in this study.

In summary of this section, both technical cycling parameters and cycling costs vary in a wide range. In the remainder of this paper, a high dynamic and a low dynamic portfolio are considered (i.e., the same set of power plants but different technical cycling parameters).

TABLE III
OVERVIEW OF THE RANGE OF TECHNICAL CYCLING DATA [23]

	Min. output [$\%P_{max}$]	Ramping [$\%P_{max}$/min]	Start/stop ramping [$\%P_{max}$/switch]	Min. up time [h]	Min. down time [h]
NUC	40-50	0.25-5	50-100	0.25-24	24
SPP-C	25-40	0.66-4	40-100	0.25-10	3-10
SPP-L	40-60	0.66-4	60-100	0.25-10	3-10
SPP-G	40	0.83-6	40-100	0.25-6	1-6
CC	30-50	0.83-10	50-100	0.25-6	0.5-6
GT	20-50	0.83-25	50-100	0.25-1	0.25-1

TABLE IV
GERMANY 2013 CONVENTIONAL GENERATION PORTFOLIO [26]

	# units	Capacity [GW]	Efficiency [%]
NUC	9	12.7	33
SPP-C	40	16.0	35/40/46
SPP-L	41	21.7	35/40/46
SPP-G	6	2.4	36/41
CC	48	15.4	40/48/58
GT	19	3.3	35/42

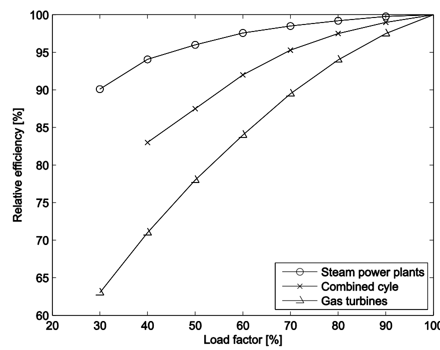


Fig. 3. Power plant efficiencies decrease in partial load operation [24],[25].

IV. MODEL DESCRIPTION

A. System description

The considered system is the 2013 German power system, consisting of a set of generation units, an inelastic load time series and an electricity grid.

The portfolio of generation units consists of conventional units, pumped storage units, renewable generation from wind, sun, conventional hydro and bio-energy, and combined heat and power generation. The optimal scheduling of the conventional units is determined by means of a generation scheduling model, namely a unit commitment model. The generation of renewables and cogeneration units is considered as given and included in the residual load. As this paper focusses on cycling of conventional power plants as the only flexibility source, pumped storage usage is considered to be fixed and included in the residual load. For all generation from renewables, cogeneration and pumped storage, historical generation time series are used. Table IV gives an overview of the installed conventional generation capacity, together with the rated efficiency of the units. Different rated efficiencies are assigned to power plants depending on the commissioning year of the plant. Installed capacity is reduced to take account of planned and unplanned outages.

Quarter-hourly demand time series originate from the German Transmission System Operators [14]-[17]. The network model used in this paper comes from the ELMOD model [27] and consists of 26 zones and 159 lines. The electricity grid is represented by a DC load flow network. Import and export is accounted for in the nodes representing the neighboring countries. According to the deterministic approach of the paper (unpredictable character of renewables is neglected), no reserve requirements are imposed. Average 2013 fuel prices and CO_2 emission price are used [28]. All system data are scaled to match aggregated data from Entso-e [29] to overcome deviation between different data sources.

B. Model description

The optimal scheduling of the power system is determined with a deterministic unit commitment model. The model is formulated as a mixed-integer linear program (MILP) in GAMS and solved using the CPLEX 12.6 solver. The model simulates each week with a quarter-hourly time resolution in optimization blocks of two days, with a stopping tolerance of 1%. Successive optimization blocks overlap one day to ensure a correct coupling between the different days.

The conventional power plants are committed and dispatched in a way that the residual load is met at minimum operational system cost. The operational system cost is the sum of production costs (fuel, CO_2 emission and variable operations and maintenance (O&M)) and cycling costs. This objective function is constrained by the market clearing constraint (supply equals demand), the technical power plant constraints (minimum and maximum power output, ramping constraints and minimum up and down time constraints) and the electricity grid constraints (limited line capacities). A detailed mathematical formulation of the unit commitment model can be found in [30].

V. Results and Discussion

A. *Impact of variable generation on conventional cycling*

Section II discussed the variability of renewables. It was concluded that wind and solar generation impacts both the variability and the average value of the residual load. This translates into a change in the amount of cycling and the type of power plants that cycle. This conclusion is illustrated in this subsection.

As more renewable generation is introduced in the system, more conventional cycling occurs. Fig. 4 shows the amount of cycling as function of the wind and solar share for a high dynamic and a low dynamic power plant portfolio (average of the considered weeks). The total amount of cycling is determined as the change in power output per quarter-hour, aggregated over all power plants (rescaled to MW per minute). The gross amount of cycling is based on the absolute value of every power output change of each individual power unit. The net amount of cycling is based on the absolute value of the aggregated power output change of the whole portfolio. Cycling clearly increases with the amount of renewable injections. The net amount of cycling is lower as upward and downward cycling plants will cancel each other to a certain extent. The net amount of cycling is about equal for both power plant portfolios as the required net amount of cycling is determined by the variability in residual load (identical for both portfolios). The minor differences between net cycling in a low dynamic and a high dynamic portfolio is caused by differences in loss of load and renewables curtailment. The difference between the gross amount of cycling and the net amount of cycling is caused by counteractive cycling, i.e. power plants cycling in the opposite direction at the same time. The power plant portfolio is forced to counteractive cycling by dynamic constraints. The difference between the gross amount of cycling and the net amount of cycling is a measure for the dynamic limits of the system. In the low dynamic portfolio, more counteractive cycling occurs, caused by the stringent dynamic limits of the system. In the high dynamic portfolio, almost no counteractive cycling occurs at small amounts of wind and sun, but at high amounts of wind and sun, counteractive cycling takes place. This shows that when the variability in residual load increases due to renewables, the high dynamic power plant portfolio becomes, relatively speaking, more stringent.

Besides the amount of cycling, the way of cycling changes as well due to renewable injections. Fig. 5 shows the contribution to cycling of each power plant type, respectively in a high dynamic portfolio (upper panel) and a low dynamic portfolio (lower panel). As more wind and solar generation is introduced in the system, more cycling comes from lignite fired plants and nuclear plants. The contribution of coal fired plants is more or less constant whereas the contribution of combined cycle plants and gas turbines diminishes with increasing wind and solar generation. In a high dynamic portfolio, nuclear units and steam power plants contribute more to cycling at high levels of wind and sun, compared to a low dynamic portfolio. In a high dynamic portfolio, these units are flexible enough to cope with the variability of renewables while in a low dynamic portfolio, combined cycle units and gas turbines are needed for flexibility delivering.

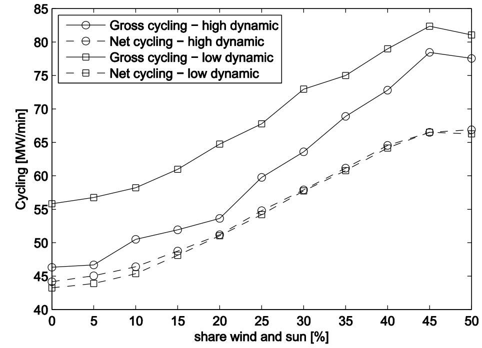
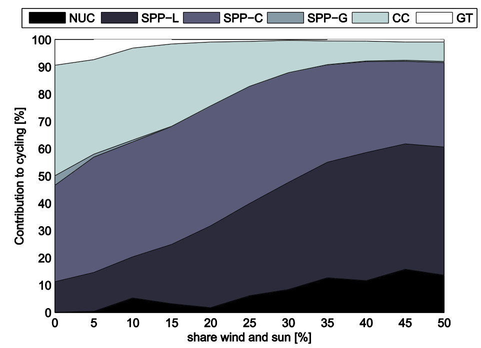
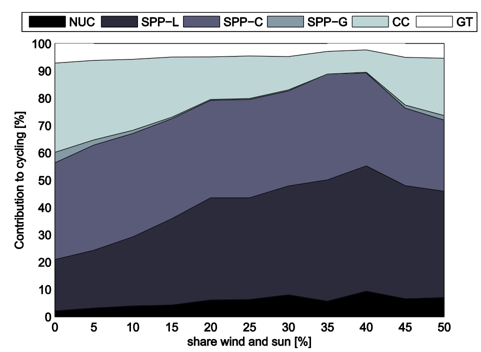


Fig. 4. The amount of cycling increases with the amount of wind and solar generation. The gross cycling does not account for counteractive cycling whereas the net cycling does.



(a) high dynamic portfolio



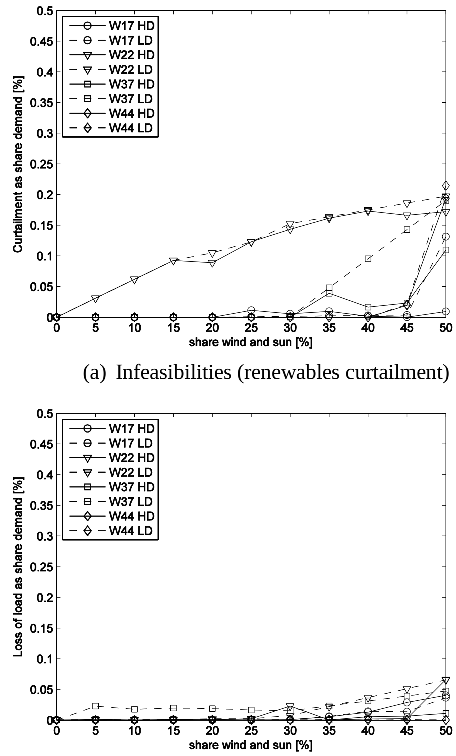
(b) low dynamic portfolio

Fig. 5. Wind and solar generation causes a shift towards base load cycling (nuclear power plants and steam power plants).

B. *Technical limits of conventional cycling*

Conventional cycling is constrained by the technical characteristics of the power plant portfolio. Wind and solar production pushes the power system towards these limits and maybe beyond, leading to system infeasibilities. The unit commitment model in this study allows load shedding (i.e., reducing the electricity demand in order to lower the residual load) and renewables curtailment (i.e., reducing the generation from wind and sun in order to increase the residual load) to avoid system infeasibilities. The cost of load shedding and renewables curtailment is set very high (10,000 EUR/MWh) to make sure that these system flexibilities are used only when all conventional cycling flexibility is depleted. Renewables curtailment occurs when renewables generation exceeds demand and when the conventional portfolio is not able to follow the variability in residual load. Only the latter reflects the cycling limitations of the conventional power portfolio. Analogously, load shedding occurs when demand exceeds available generation capacity and when the conventional portfolio is not able to follow the variability in residual load. Again, only the latter reflects the cycling limitations of the conventional power portfolio.

Fig. 6 shows the “amount of infeasibilities”, expressed as share of demand, caused by the limitations of conventional cycling to cope with variable wind and solar generation. Both types of infeasibilities - renewables curtailment and loss of load - are very small (less than 0.25% of demand) for renewables shares up to 50%. There is no difference between the low dynamic portfolio and the high dynamic portfolio (the minor differences between both portfolios are within the tolerance margin of the solution process). It turns out that the 2013 German conventional power plant portfolio is able to facilitate the variability of wind and sun up to at least wind and solar shares of 50%, regardless of the technical cycling parameters allocated to the portfolio in the unit commitment model (high dynamic versus low dynamic). In other words, the dynamic limits of conventional power plant cycling are not yet reached at 50% wind and solar share, even not if stringent cycling parameters are assigned to the power plants in the portfolio.



(a) Infeasibilities (renewables curtailment)

(b) Infeasibilities (loss of load)

Fig. 6. There are very little system infeasibilities caused by the limitations of conventional cycling to cope with variability in wind and sun (HD: high dynamic portfolio, LD: low dynamic portfolio).

C. *The cost of cycling*

Section III mentioned five types of cycling costs: direct start costs, indirect start costs, forced outage costs, ramping costs and efficiency costs. These different costs are often hard to quantify, except for the direct start cost (i.e., fuel and CO_2 emission cost during start-up), and vary in a wide range depending on the plant characteristics. Therefore, it is not straightforward to determine the cycling cost that has to be taken into account during the generation scheduling. Table V shows average cycling cost data for the different types of power plants.

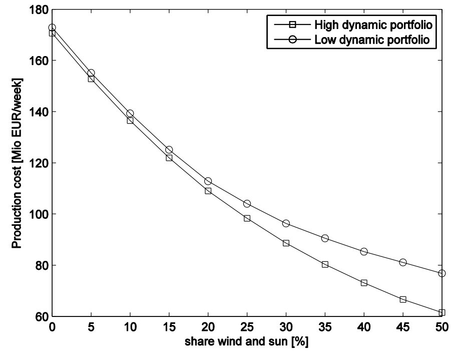
TABLE V
CYCLING COSTS (AVERAGE VALUES) [22]

	Direct start [€/ΔMW]	Indirect start [€/ΔMW]	Forced outages [h/cycle]	Ramping [€/ΔMW]	Efficiency decrease [%-p/cycle]
NUC	35	-	-	-	-
SPP-C	25	55	0.63	1.8	0.44
SPP-L	28	55	0.63	1.8	0.44
SPP-G	33	40	0.39	1.4	0.20
CC	5	40	0.35	0.5	0.20
GT	2.4	40	0.69	0.8	0.10

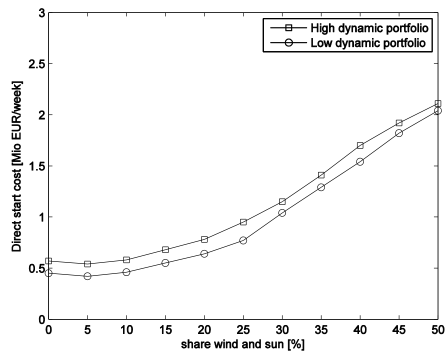
In all simulations so far, only the direct start costs are taken into account in the unit commitment model, assuming that the operator has no information about the other cycling costs. Fig. 7 shows the resulting operational system cost as function of the amount of wind and solar. The total operational system cost consists of production costs and cycling costs[1]. The production cost includes fuel cost, CO_2 emission cost, and variable O&M cost. The production cost declines when wind and solar injections are introduced (see upper panel of Fig. 7, average values for considered weeks). The low dynamic portfolio has higher production costs than the high dynamic portfolio as more expensive power plants have to be online to deliver flexibility (i.e., combined cycle units and gas turbines), whereas in the high dynamic portfolio, the flexibility can be delivered by less expensive power plants (e.g., steam power plants). A high dynamic portfolio entails production cost savings with respect to a low dynamic portfolio, which increases with increasing wind and solar generation. The direct start costs on the other hand rise with increasing wind and solar generation (see lower panel of Fig. 7, average values for considered weeks). The high dynamic portfolio has slightly higher start costs as more startups occur in this portfolio. The decrease in production costs due to renewable injections is about two orders of magnitude larger than the increase in direct start costs.

The production cost, shown in Fig. 7 (a), includes partial load operation. Increasing renewables generation tends to increase the partial load operation of conventional plants. In partial load, power plants generate at efficiencies below their rated efficiency (see Fig. 3). This efficiency effect is included in the production costs, which are calculated based on the actual operating efficiency of the power plants. Recalculating the production costs at rated efficiency (same generation, but primary fuel emission costs determined with the rated efficiency instead of the actual operating efficiency) gives a production costs which is 0-3% lower. The cost of partial load operation is hence rather small compared to the renewables cost savings.

[1] The cost of load shedding and renewables curtailment is, within the scope of this study, a system infeasibility cost, not a regular operational system cost.



(a) Production cost



(b) Direct start cost

Fig. 7. The reduction in production cost due to wind and solar generation outweighs the increase in direct start costs (average for considered weeks).

The total cycling costs can be calculated ex-post based on the data in Table V and turns out to be about a factor 5 to 10 higher than the direct start costs (see Fig. 8). The reduction in production cost due to renewables however still outweighs the increase in total cycling costs. The indirect start cost, representing capital replacement and maintenance costs, is about 40% of total cycling costs. The ramping costs, i.e., capital and maintenance costs due to load following, are rather small. The costs of increased forced outages caused by cycling are about 5% of total cycling cost. Each startup/shutdown cycle results in a small increase in the forced outage rate. The cost of forced outages is the value lost due to these extra outages. In this paper, it is assumed that the lost generation is replaced by gas turbines. The cost of forced outages is given by the difference between the cost of replacing the lost generation with gas turbines and the cost of the original generation. Finally, cycling causes a decrease in rated efficiency. The cost of this decreasing rated efficiency can be expressed as the difference in production cost between a case with all production at the decreased efficiency and a case with all production at the original efficiency. The costs of increasing forced outage rates and decreasing rated efficiencies are calculated per week. However, these costs might persist for the remaining life time of the power plant if no proper maintenance and replacement actions are taken.

Up to now, only the direct start cost was taken into account in the unit commitment model. By taking the total cycling cost into account during the generation scheduling, the total cycling cost decreases. Fig. 9 shows the total cycling cost, as function of the wind and solar share, if only the direct start costs are taken into account (solid line) and if total cycling

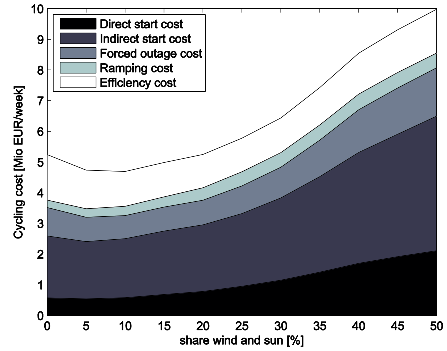


Fig. 8. The total cycling cost is about a factor 5 to 10 higher than the direct start cost (average data for considered weeks, high dynamic portfolio).

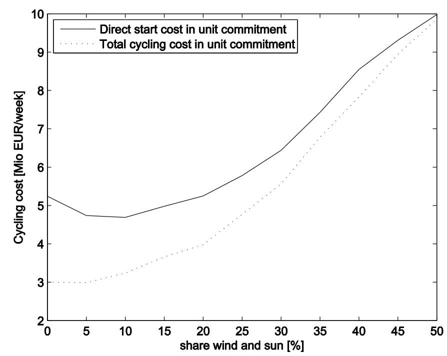


Fig. 9. Cycling costs decrease if they are taken into account in the unit commitment decision (average data for all considered weeks, high dynamic portfolio).

TABLE VI
COST OVERVIEW FOR DIFFERENT LEVELS OF WIND AND SUN (HIGH DYNAMIC PORTFOLIO, ALL CYCLING COSTS IN MODEL)

[Mio €/week]	0%	25%	50%
Production cost	170.6	98.3	61.5
Cycling cost	3.0	4.8	9.8
Total cost	173.6	103.1	71.3

costs are taken into account in the unit commitment (dashed line). The solid line gives the total cycling costs as shown in Fig. 8. The difference between the solid and the dashed line indicates the possible cost savings by taking all cycling costs into account in the unit commitment decision. At low renewable generation (up to 20% wind and solar share), about 1% of the operational system cost can be saved. At higher wind and solar generation the cycling costs converge as cycling is needed to keep the system feasible, regardless of its costs. The production costs are barely influenced by the cycling costs taken into account in the unit commitment model.

In conclusion of this subsection, Table VI gives an overview of the operational system costs for three levels of wind and solar generation. The production costs decrease with increasing renewable generation due to less fossil fuel consumption. The fossil fuel savings largely outweigh the decrease in operating efficiencies due to partial load operation. All types of cycling costs increase with increasing renewables. Overall, the total operational system cost decreases with increasing renewable generation. This conclusion holds for the low and the high dynamic portfolio.

VI. Conclusion

The variable character of wind and solar generation requires operational flexibility in the power system. One source of operational flexibility is conventional power plant cycling. Conventional power plant cycling is constrained by the dynamics of the power portfolio and entails a range of costs. This paper quantifies the limits and costs of conventional power plant cycling as flexibility source to facilitate variable generation from wind and sun, based on a case study of the German 2013 power system.

The effect of wind and solar generation on conventional cycling is twofold: (1) wind and solar generation leads to an increase in cycling of the conventional power portfolio and (2) wind and sun lower the residual load (i.e., electricity demand minus renewable generation) which forces base load units to cycle. Under the assumptions made in this paper, conventional power plant cycling is able to cope with the variability in wind and solar generation up to renewable shares of 50% (2013 wind and solar share was 16.5%).

All different types of cycling costs rise with increasing renewable generation. However, his cost increase is outweighed by the fuel cost savings, even if partial load costs are taken into account. Renewable generation hence cause a decrease in operational system costs.

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