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Abstract

Cycling of conventional generation units is an important source of operational flexibility in the electricity generation system. Cycling is changing the power output of conventional units by means of ramping and switching (starting up and shutting down). In the literature, a wide range of technical and cost-related cycling parameters can be found. Different studies allocate different cycling parameters to similar generation units. This paper assesses the impact of different cycling parameters allocated to a conventional generation portfolio. Both the technical limitations of power plants and all costs related to cycling are considered. The results presented in this paper follow from a unit commitment model, used for a case study based on the German 2013 system. The conventional generation portfolio has to deliver different residual load time series, corresponding to different levels of renewables penetration. The study shows, under the assumptions made, that although the dynamic limits of some units are reached, the limits of the conventional generation portfolio as a whole are not reached, even if stringent dynamic parameters are assigned to the generation portfolio and a highly variable residual load is imposed to the system. The study shows also the importance of including full cycling costs in the unit commitment scheduling. The cycling cost can be reduced by up to 40% when fully taken into account.

Keywords: Power plant cycling, cycling costs, power plant scheduling.

1. Introduction

The way of operating conventional power plants is changing as a consequence of the increasing penetration of intermittent renewables in the electricity generation system [1]. Electricity generation from intermittent renewable sources, like wind energy and solar energy, is variable, partly unpredictable and not or limitedly dispatchable [2]. As a consequence, a flexible electricity system is required to deal with the variations in renewable generation and to cope with forecast errors [3]. Holttinen estimated that, for a 10% energy penetration level of wind in Scandinavia, reserve requirements increase with 1.5-4% of installed with capacity [4]. Albadi and El-Saadany foresee an increase in balancing costs with increasing wind penetration [5].

A well developed and flexible grid, responsive electricity demand, curtailment of renewable generation and storage of electric energy are often cited as operational flexibility options to accommodate intermittent renewables in the electricity generation system [6]. However, these flexibility sources are only to a limited extent available in current systems. The main source of operational flexibility nowadays is cycling of conventional power plants. Cycling is defined as changing the output of a power plant by starting up, shutting down, ramping up or ramping down [7]. Conventional power plants refer to centralized and dispatchable units, like nuclear power plants, coal and lignite-fired steam power plants, and gas-fired plants.

The integration of intermittent renewables in the electricity generation system causes an increase in conventional power plant cycling. The link between renewables deployment and cycling behavior of conventional power plants is extensively discussed in the literature. Troy et al. show that, based on a case study of the 2020 Irish electricity system, cycling of base-load generation units increase with increasing wind penetration [8]. Cochran et al. discuss the evolution of coal fired units from base-load to peak-load generation [9]. Tuohy et al. show that more robust and cost efficient generation schedules are produced by stochastic optimization which takes account of the intermittent character of renewables [10]. Although cycling (costs) are increasing at higher renewables penetration, overall operational generation costs decrease due to fossil fuel savings as shown by Strbac et al. for a case study of the UK [11] and by Ummels et al. for the Dutch system [12].

Different studies allocate different cycling parameters – costs and technical limits – to similar generation units. In the literature, a wide range of technical cycling parameters is reported. However the sensitivity of the allocated cycling parameters on the final cycling behavior is never investigated. This paper complements the existing literature on conventional power plant cycling by focusing on the cycling parameters itself and their impact on cycling behavior, rather than on the cause of the increased cycling behavior.

An important question is how flexible conventional generation units are – from a technical viewpoint – and what the additional costs are related to a flexible operation of these units [13]-[14]. This paper investigates the influence of the variability in technical parameters on the operation of power plants. The scheduling of the same set of power plants is optimized for a case with high-dynamic cycling parameters and a case with low-dynamic cycling parameters assigned to the power plants. In addition, the different costs of conventional cycling and their impact on the total generation costs are quantified in this study. The results presented in this paper follow from a case study based on the 2013 German generation system. A dedicated operational partial equilibrium model of the electricity generation sector, i.e., a unit commitment model, is developed for this study.

The added value of this paper lies in its focus on the uncertainty related to cycling parameters – both technical and cost-related parameters. To address this issue, the impact of different cycling parameters on the power plant scheduling is studied. As such, this study contributes to the ongoing discussion on compatibility between variable generation of renewables and conventional electricity generation [15].

Section 2 discusses the technical and cost-related aspects concerning conventional power plant cycling. Section 3 presents the 2013 German electricity generation system as a case study and describes the unit commitment model used in this paper. Section 4 presents the results and discussion. Section 5 concludes.

2. Cycling of conventional units

Cycling of conventional units causes additional costs for generators and is limited by the technical characteristics of the unit. Both aspects are discussed in detail in this section.

2.1. Cycling cost

Cycling has a degenerating effect on units. When a generation unit varies its output, various components in the unit are subject to stresses and strains. During the shutdown of a unit, components undergo large temperature and pressure stresses. These stresses and strains lead to accelerated component failures and forced outages [16]. 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 [17].

The cost associated with power plant cycling consists of several components. Kumar et al. mention 5 distinct groups of cycling costs [18]:

(1) the cost for fuel, CO_2 emissions and auxiliary services during start-up, further referred to as direct start costs;

(2) the capital replacement costs and maintenance cost due to start-ups, further referred to as indirect start costs;

(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 costs;

(4) the capital replacement costs and maintenance cost related to load following, further referred to as ramping costs;

(5) the cost of a decrease in rated efficiency due to cycling, further referred to as efficiency costs.

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 (i.e., direct start cost) into account when making unit commitment decisions, even though this cost might be quite small compared to the total cycling cost. Cycling costs depend on many factors like the type and age of the power plant. It is difficult to put one number on the cycling costs of conventional power plants. According to Lefton et al., 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. [16]. Similarly, Kumar et al. report cycling costs with a factor 100 difference between the lowest and highest cycling cost [18]. A study of Schröder et al. on the costs of electricity generation also reports such a wide range of cycling costs [19]. In an electricity generation system with increasing levels of renewables, cycling costs are a growing concern for power plant operators and system operators. Therefore, taking the correct cycling costs into account during the scheduling of the units is of great importance.

An important challenge is to allocate correctly the long-term cycling costs, such as indirect start costs and efficiency costs, into a short-term operational decision like power system scheduling. One possible approach is to model cycling cost dynamically, i.e., as a function of the number of start-ups [20]. This approach is especially valuable when looking at one generation unit in detail. Another approach, more common for studies with a system perspective, is to work with one fixed start-up costs for each generation type. This start-up cost represents the short-term operational costs related to the start-up, but a markup is added to correct for long-term costs. The latter approach is applied in this paper.

2.2. Dynamic limits

Technical limits 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 imposes minimum up and down times. Conventional power plant cycling is also closely related to partial load operation. Operating a power plant at less than its rated power output goes together with a decrease in operating efficiency.

In the literature a wide range of cycling parameters, used in generation scheduling models, can be found. Table I gives an overview of outer limits of cycling parameters and Figure 1 shows typical part load efficiency curves (as used in this study). 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) The cycling parameters allocated to power plants might hence reflect just 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, but with different cycling parameters. In the low-dynamic portfolio, the power plants have stringent cycling parameters (see Table I, upper bound of minimum power output, lower bound of ramping gradients and upper bound of minimum up and down times). In the high-dynamic portfolio, less constraining cycling parameters are assigned to the same set of power plants (see Table I, lower bound of minimum power output, 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 limits reflect a more conservative mode of operation). In both portfolios, the operators face the same cost parameters for generation and cycling.

Table I. Overview of the range of technical cycling data [19] (NUC: nuclear power plants; SPP-C: coal-fired steam power plants; SPP-L: lignite-fired steam power plants; SPP-G: gas-fired steam power plants; CCGT: combined-cycle gas turbines; OCGT: open-cycle gas turbines).

	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

CCGT	30-50	0.83-10	50-100	0.25-6	0.5-6
OCGT	20-50	0.83-25	50-100	0.25-1	0.25-1

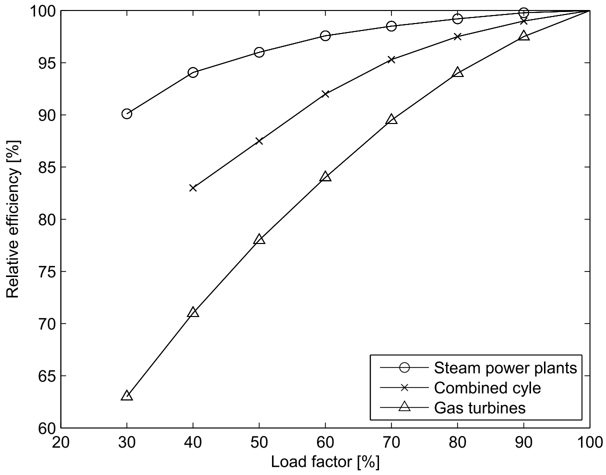

Figure 1. Power plant efficiencies decrease in partial load operation [21]-[22].

3. Model description

The studied electricity generation system is based on the 2013 German system. Cycling of conventional units within this system is simulated by means of a dedicated operational partial equilibrium model of the power sector, i.e, a unit commitment model. The studied system and the model are discussed in this section.

3.1. *System description*

The considered system is based on the 2013 German electricity generation system, consisting of a set of conventional generation units, a demand time series[1], renewable generation time series and an electricity grid. A unit commitment model is used to

[1]The electricity demand time series is corrected for generation from cogeneration units, generation/consumption of pumped hydro units and import/export with neighboring countries.

determine the optimal scheduling of the conventional units in order to meet the residual load. The residual load is calculated as the (inelastic) electricity demand minus generation from renewables. The variability and the magnitude of the residual load both have an impact on the cycling behavior of the conventional portfolio. Four weeks are considered in detail, reflecting all different combinations of variability and magnitude of the residual load[2].

The residual load time series is imposed to the conventional portfolio, which has to follow this variable residual load by means of cycling. The residual load time series is determined as the original demand time series minus the renewable time series. Different renewables time series are considered by scaling up or down the historical time series, reflecting different levels of renewables generation. Historical time series for the original demand and renewable generation with a quarter-hourly time resolution originate from the TSO [23]-[26].

Table II gives an overview of the installed conventional generation capacity, together with the rated efficiency of the units [27]. Different rated efficiencies are assigned to power plants depending on the commissioning year of the plant. The highest rated efficiency is allocated to units commissioned or retrofitted after 2000, the middlemost to units commissioned between 1980 and 2000, and the lowest to units commissioned before 1980.

The grid model used in this paper comes from the ELMOD model and consists of 26 zones and 159 lines [28]. The electricity grid is represented by a DC power flow network.

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[2]The following weeks are considered in detail; April 22-28 (week 17, low average load, high variable load), May 27-June 2 (week 22, low average load, low variable load), Sept 9-15 (week 37, high average load, high variable load), and Oct 28-Nov 3 (week 44, high average load, low variable load).

Average 2013 fuel prices and CO_2 emission price are used [29]. All system data are scaled to match aggregated data from ENTSO-E to overcome deviation between different data sources [30].

Load shedding and curtailment of renewable generation is possible at a very high cost (10,000 EUR/MWh). Loss of load and curtailment both indicate system infeasibilities.

Note that the authors do not aim to simulate the operation of the electricity market, but are rather focusing on the techno-economic characteristics of the electricity generation system. Several differences between the electricity market design and this study exists. For instance, no electricity grid constraints within bidding zones are taken into account in the electricity market clearing, whereas this paper considers a full DC power flow of the studied electricity generation system.

Table II. Germany 2013 conventional generation portfolio [27] (NUC: nuclear power plants; SPP-C: coal-fired steam power plants; SPP-L: lignite-fired steam power plants; SPP-G: gas-fired steam power plants; CCGT: combined-cycle gas turbines; OCGT: open-cycle gas turbines).

	# 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
CCGT	48	15.4	40/48/58
OCGT	19	3.3	35/42

3.2. Model description

The optimal scheduling of the electricity generation system is determined with a dedicated 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 considered week with a quarter-hourly time resolution.

Hereunder, the basic equations of the unit commitment model are listed [31]-[32]. Table III gives the nomenclature used in the model description.

Table III. Nomenclature used in the model description.

Sets		**Parameters**	
I (i)	Set of power plants	$A_{n,i}$	matrix linking plant i to node n {0,1}
L (l)	Set of transmission lines	C_i	generation cost at min. output [€/qh]
N (n)	Set of nodes	CC	cost of curtailment [0.25€/MWh]
T (t)	Set of time steps	$D_{n,t}$	electricity demand [MW]
		F_l^{max}	line capacity limit [MW]

Variables			
$c_{n,t}^{curt}$	curtailment cost [€/qh]	MC_i	marginal generation cost[0.25€/MWh]
$c_{i,t}^{gen}$	generation cost [€/qh]	MDT_i	minimum down time [h]
$c_{n,t}^{lol}$	loss of load cost [€/qh]	MUT_i	minimum up time [h]
$c_{i,t}^{ramp}$	ramping cost [€/qh]	P_i^{max}	maximum power output [MW]
$c_{i,t}^{start}$	start-up cost [€/start]	P_i^{min}	minimum power output [MW]
$cur_{n,t}$	curtailment [MW]	$PTDF_{l,n}$	power transfer distribution factor
$inj_{n,t}$	grid injections [MW]	$RES_{n,t}$	renewables generation [MW]
$f_{l,t,}$	line flow [MW]	RC_i	ramping cost [€/MW]
$ll_{n,t}$	lost load [MW]	RD_i	ramping-down limit [MW]
$p_{i,t}$	output above min output [MW]	RU_i	ramping-up limit [MW]
$v_{i,t}$	start-up status {0,1}	SD_i	shut-down limit [MW]
$w_{i,t}$	shut-down status {0,1}	SU_i	start-up limit [MW]
$z_{i,t}$	on/off-status {0,1}	SUC_i	start-up cost [€/start]
		VOLL	value of lost load [0.25€/MWh]

The objective function of the unit commitment model is minimization of the total operational system cost, consisting of generation costs, start-up costs and ramping costs.

$$\min \sum_i \sum_t \left(c_{i,t}^{gen} + c_{i,t}^{start} + c_{i,t}^{ramp}\right) + \sum_n \sum_t \left(c_{n,t}^{curt} + c_{n,t}^{lol}\right) \quad (1)$$

with the costs defined as follows;

$$c_{i,t}^{gen} = C_i\, z_{i,t} + MC_i\, p_{i,t} \quad \forall\, i, t \quad (2)$$

$$c_{i,t}^{start} = SUC_i\, v_{i,t} \quad \forall\, i, t \quad (3)$$

$$c_{i,t}^{ramp} \geq RC_i \left(p_{i,t} - p_{i,t-1} - v_{i,t}\, P_i^{max}\right) \quad \forall\, i, t \quad (4)$$

$$c_{i,t}^{ramp} \geq RC_i \left(p_{i,t-1} - p_{i,t} - w_{i,t} P_i^{max}\right) \quad \forall\, i, t \tag{5}$$

$$c_{i,t}^{ramp} \geq 0 \quad \forall\, i, t \tag{6}$$

$$c_{n,t}^{curt} = CC\, cur_{n,t} \quad \forall\, n, t \tag{7}$$

$$c_{n,t}^{lol} = VOLL\, ll_{n,t} \quad \forall\, n, t \tag{8}$$

The parameter P^{max} in Equations 4-5 forces the ramping cost to be zero if a power plant is started up or shut down. The objective function is subject to the market clearing condition (Eq. 9), power plant generation limits (Eq. 10), power plant ramping limits (Eq. 11-12), minimum down and up times (Eq. 13-14), the binary relation (Eq. 15), the DC power flow equations (Eq. 16), the transmission line limits (Eq. 17), renewables curtailment limit (Eq. 18), loss of load limit (Eq. 19) and binary constraints (Eq. 20).

$$\sum_i A_{n,i} \left(z_{i,t}\ P_i^{min} + p_{i,t}\right) + RES_{n,t} - cur_{n,t} = D_{n,t} - ll_{n,t} + inj_{n,t} \quad \forall\, n, t \tag{9}$$

$$0 \leq p_{i,t} \leq \left(P_i^{max} - P_i^{min}\right) z_{i,t} \quad \forall\, i, t \tag{10}$$

$$\left(p_{i,t} - p_{i,t-1}\right) \leq RU_i\, z_{i,t-1} + (SU_i - P_i^{min})\, v_{i,t} \quad \forall\, i, t \tag{11}$$

$$\left(p_{i,t-1} - p_{i,t}\right) \leq RD_i\, z_{i,t} + (SD_i - P_i^{min})\, w_{i,t} \quad \forall\, i, t \tag{12}$$

$$1 - z_{i,t} \geq \sum_{t'=t+1-MDT_i}^{t} w_{i,t'} \quad \forall\, i, t \tag{13}$$

$$z_{i,t} \geq \sum_{t'=t+1-MUT_i}^{t} v_{i,t'} \quad \forall\, i, t \tag{14}$$

$$z_{i,t-1} - z_{i,t} + v_{i,t} - w_{i,t} = 0 \quad \forall\, i, t \tag{15}$$

$$f_{l,t} = \sum_n PTDF_{l,n}\, inj_{n,t} \quad \forall\, l, t \tag{16}$$

$$-F_l^{max} \leq f_{l,t} \leq F_l^{max} \quad \forall\, l, t \tag{17}$$

$$0 \leq cur_{n,t} \leq RES_{n,t} \quad \forall\, n, t \tag{18}$$

$$0 \leq ll_{n,t} \leq D_{n,t} \quad \forall\, n, t \tag{19}$$

$$v_{i,t}, w_{i,t}, z_{i,t} \in \{0,1\} \quad \forall n,t \tag{20}$$

The model is validated so that the generation in a simulation with historical input data matches the historical observed fuel mix. It takes about 3 hours to solve the unit commitment model for one week with the low-dynamic portfolio and 1 hour with the high-dynamic portfolio (163 power plants, 672 time steps, 1% relative optimality gap, solved on an Intel® Core™ i7-2620M CPU @ 2.7 GHz with 8 GB RAM).

4. Results and discussion

The conventional generation portfolio is scheduled for different residual load time series, corresponding to different levels of wind and sun in the electricity generation system. Higher renewables shares lead to more variable and on average lower residual load time series. In this results section, the different residual load time series are referred to with their corresponding share of wind and sun.

4.1. Cycling in a high and low-dynamic portfolio

Figure 2 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, which is consistent with results presented in the literature. However, this paper distinguishes between net and gross cycling and between a low-dynamic and a high-dynamic portfolio. The net amount of cycling is lower as upward and downward cycling plants will cancel each other out 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 are 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. Without any dynamic constraint, no counteractive cycling would occur as every operating unit would produce at rated power output and only the last generating unit would operate in partial load. With dynamic constraints, counteractive cycling occurs. Hence, the difference between the gross amount of cycling and the net amount of cycling is a measure for the dynamic limits of the whole generation portfolio. 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.

Besides the amount of cycling, the way of cycling changes as well. Figure 3 shows the contribution to cycling of each power plant type, respectively in a high-dynamic portfolio (Figure 3a) and a low-dynamic portfolio (Figure 3b). 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 in residual load whereas in a low-dynamic portfolio, combined-cycle units and gas turbines are needed.

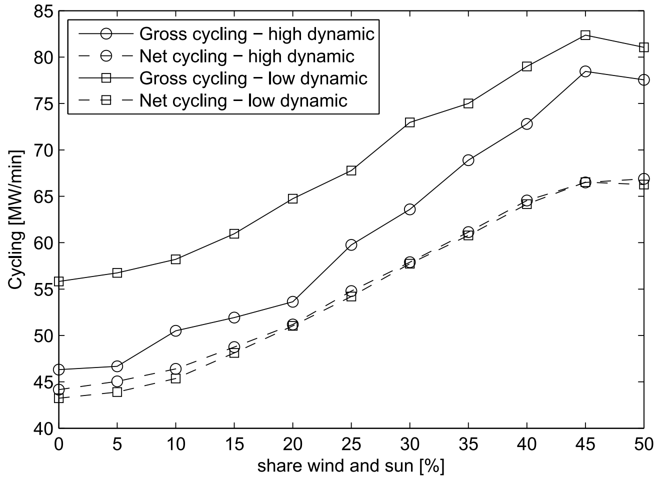
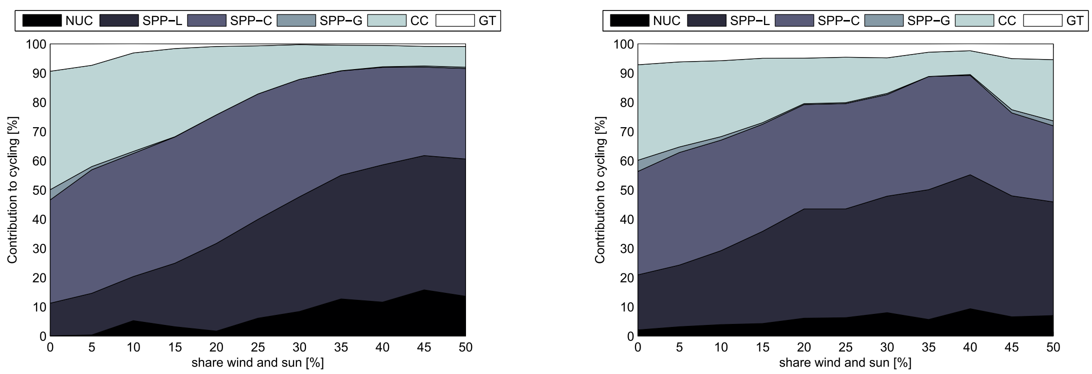


Figure 2. The amount of cycling increases with the amount of wind and solar generation (average cycling in the considered weeks). The gross cycling does not account for counteractive cycling whereas the net cycling does.



(a) high-dynamic portfolio

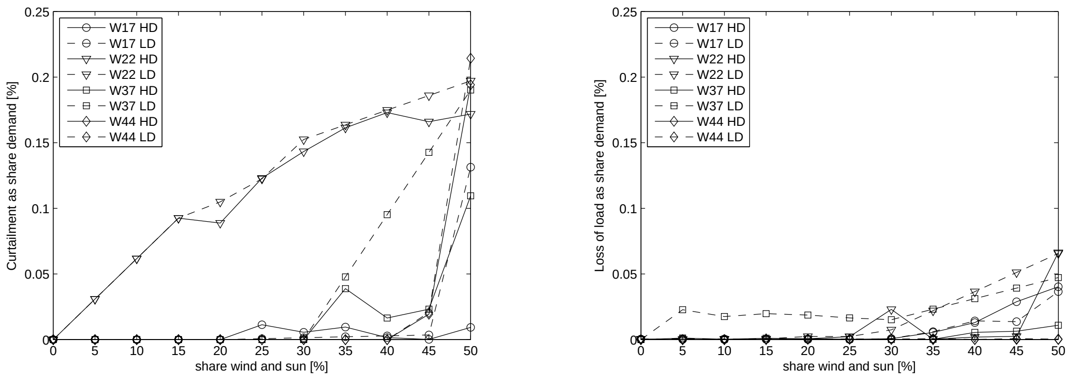
(b) low-dynamic portfolio

Figure 3. Wind and solar generation causes a shift towards base load cycling (average cycling in the considered weeks).

4.2. Technical limits of cycling

Conventional cycling is constrained by the technical characteristics of the power plant portfolio. Wind and solar generation pushes the electricity generation 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 or when the conventional portfolio is not able to follow the variability in residual load. Only the latter reflects the cycling limits of the conventional generation portfolio. Analogously, load shedding occurs when demand exceeds available generation capacity or when the conventional portfolio is not able to follow the variability in residual load. Again, only the latter reflects the cycling limits of the conventional generation portfolio.

Figure 4 shows the “amount of infeasibilities”, expressed as share of demand, caused by the limits of conventional cycling to cope with a variable residual load. Both types of infeasibilities – renewables curtailment and loss of load – occur rarely (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 conventional power plant portfolio is able to deliver the flexibility up to a level corresponding to 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 the conventional portfolio as a whole are not reached, even not if stringent cycling parameters are assigned to the generation portfolio. However, certain power plants might be bounded in operation.



(a) infeasibilities (renewables curtailment) (b) infeasibilities (loss of load)

Figure 4. Very little system infeasibilities, caused by the limits of conventional cycling, occur (HD: high-dynamic portfolio, LD: low-dynamic portfolio, weekly aggregated).

4.3. *The cost of cycling*

Section 2 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 IV shows average cycling cost data for the different types of power plants.

Table IV. Cycling costs – average values [18] (NUC: nuclear power plants; SPP-C: coal-fired steam power plants; SPP-L: lignite-fired steam power plants; SPP-G: gas-fired steam power plants; CCGT: combined-cycle gas turbines; OCGT: open-cycle gas turbines).

	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
CCGT	5	40	0.35	0.5	0.20
OCGT	2.4	40	0.69	0.8	0.10

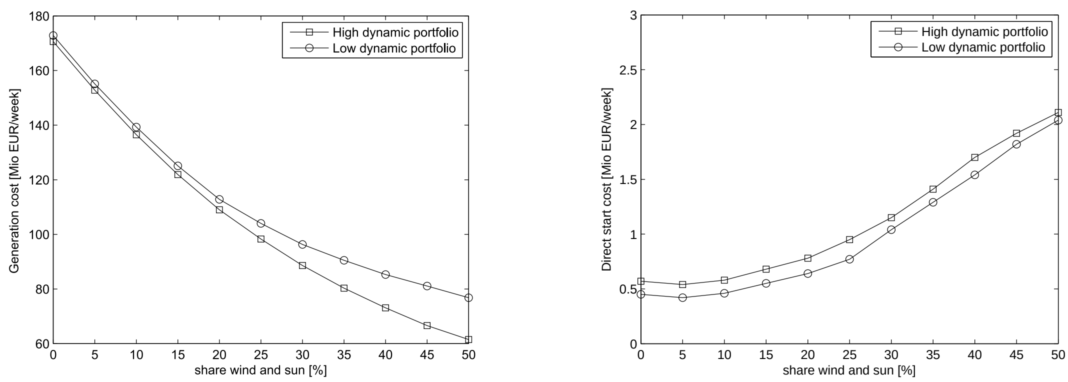
In all simulations so far, only the direct start costs are taken into account in the unit commitment model, assuming that the operator has no information about the other cycling costs or that these other costs are zero. Figure 5 shows the resulting operational system cost. The total operational system cost consists of

costs and cycling costs[3]. The generation cost includes fuel costs, CO_2 emission costs and variable operations and maintenance (O&M) costs. The generation cost declines when wind and solar injections are introduced (Figure 5a). The low-dynamic portfolio has higher generation costs than the high-dynamic portfolio as more expensive power plants have to

[3]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, and therefore excluded from Figure 5.

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 (i.e., steam power plants). A high-dynamic portfolio entails generation cost savings with respect to a low-dynamic portfolio, which increases with increasing renewables generation. The direct start costs on the other hand rise with increasing wind and solar generation (Figure 5b). The high-dynamic portfolio has slightly higher start costs as more startups occur in this portfolio. The decrease in generation costs due to renewable injections is in this case about two orders of magnitude larger than the increase in direct start costs.

The generation cost, shown in Figure 5a, 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 Figure 1). This efficiency effect is included in the generation costs, which are calculated based on the actual operating efficiency of the power plants. Recalculating the generation costs at rated efficiency (same generation, but primary fuel emission costs determined with the rated efficiency instead of the actual operating efficiency) gives a generation costs which is 0-3% lower. The cost of partial load operation is hence rather small compared to the renewables cost savings.



(a) generation cost (b) direct start cost

Figure 5. The reduction in generation cost due to wind and solar generation outweighs the increase in direct start costs (average for considered weeks).

The potential total cycling costs can be calculated ex-post based on the data in Table 4 and turns out to be about a factor 5 to 10 higher than the direct start costs in this case (see Figure 6). The reduction in generation 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 start-up/shut-down 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 generation cost between a case with all generation at the decreased efficiency and a case with all generation 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 full cycling cost into account during the generation scheduling, the total cycling cost decreases. Figure 7 shows the total cycling cost if only the direct start costs are taken into account (solid line) and if total cycling costs are taken into account in the unit commitment (dashed line). The solid line gives the total cycling costs as shown in Figure 6. 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, about 25-40% of the total cycling cost can be saved (equal to about 1% of the total operational system cost). At higher renewables share the cycling costs converge as cycling is needed to keep the system feasible, regardless of its costs. The generation costs are barely influenced by the cycling costs taken into account in the unit commitment model.

In conclusion of this subsection, the generation 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. These results are consistent with the literature. This paper additionally shows that 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.

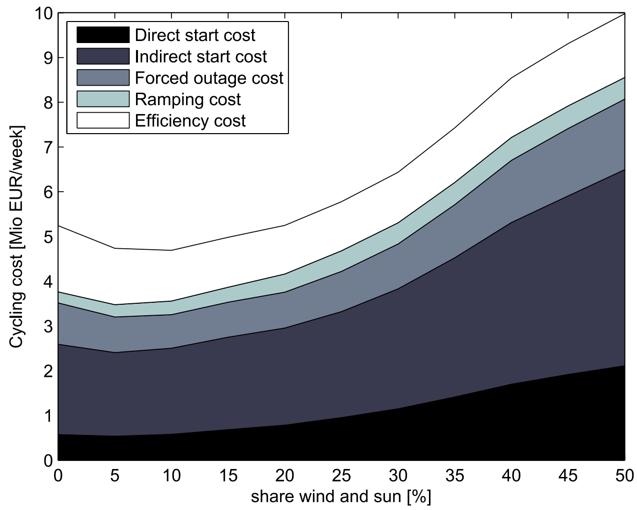


Figure 6. The total cycling cost is about a factor 5 to 10 higher than the direct start cost (average data for considered weeks, high-dynamic portfolio).

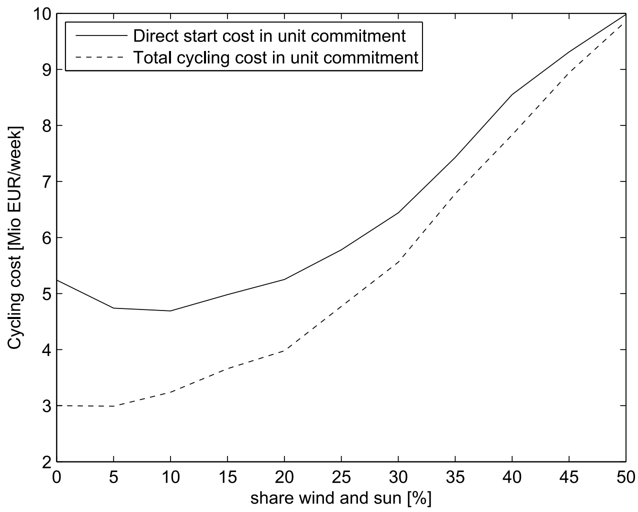


Figure 7. Cycling costs decrease if they are taken into account in the unit commitment decision (average data for all considered weeks, high-dynamic portfolio).

5. Conclusion

Conventional power plant cycling is an important source of operational flexibility in an electricity generation system with a large penetration level of intermittent renewables like wind and sun. Cycling is constrained by the dynamic limits of the generation portfolio and entails a range of costs. This paper quantifies the limits and costs of conventional power plant cycling, based on a case study inspired by the German 2013 electricity generation system. The focus of this paper lies on the wide range of cycling parameters reported in the literature and their impact on the cycling behavior of the conventional generation portfolio.

Two different sets of dynamic parameters are assigned to the same set of power plants. The first set represents a low-dynamic portfolio whereas the second set corresponds to a high-dynamic portfolio. It turns out that both portfolios are able to meet the residual load (i.e., the electricity demand minus generation from renewables), even up to a level where the residual load corresponds to a 50% wind and solar share. In other words, the dynamic limits of the generation portfolio as a whole are not reached.

All different types of cycling costs rise with increasing variability in the residual demand. The direct start-up cost, which is often the only cycling cost included in unit commitment models, could be only 10-20% of the total cycling cost. Considering all cycling costs in the unit commitment scheduling can decrease the total cycling cost with up to 40%. This paper solely focusses on the costs caused by cycling of a power plant in the day-ahead electricity market. However, other revenue streams for a power plant operator might exist besides the day-ahead market, e.g., remunerations for ancillary services or capacity payments, which should also be considered in assessing the economic viability of a power plant.

Cycling of conventional units could be reduced by increasing the availability of other short-term flexibility options, such as electric storage, demand response, curtailment of renewable generation and increased transmission flexibility. For instance, in terms of system inertia, a lot is expected from renewables contributions connected through power electronics. Future work should address these other flexibility options and investigate the reduction in cycling costs that can be achieved by deploying them.

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