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A parametric approach for the valuation of power plant flexibility options

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ABSTRACT

Conventional generation units encounter a changing role in modern societies' energy supply. With increased need for flexible operation, engineers and project managers have to evaluate the benefits of technical improvements. For this purpose, a valuation tool has been developed, comparing economical cornerstones and technical constraints of generation units to European Energy Exchange prices for PHELIX 2014. It enables the user to relate a change in technical parameters to an economic effect and possible revenues. Four different types of conventional power plants are investigated in scenarios with increasing CO_2 and fuel prices to determine the impact of different flexibility options. Results show that an increased ramp rate has not the same magnitude of positive economic impact as reduced minimum operation load, based on an observation on a price signal with resolution of fifteen minutes.

1. Introduction

Modern society's energy supply undergoes a fundamental transformation from a carbon-based to a nature-based energy production by the extended use of renewable energies (RE). The key factor driving development in Germany's energy sector is the German Renewable Energy Act (EEG), which introduces tariffs for renewable electricity feed-in and imposes carbon footprint reduction in the future by replacing conventional units with RE capacity (Bundesnetzagentur and Bundeskartellamt, 2014). Conventional units are used to adjust their production to the remaining residual load profile on the fly, which leads to an underestimation of true power plant value on a day-ahead basis. Hard coal and combined-cycle gas plants need to operate with fewer full-load hours than planned, and former valuation methods may lead to misleading results. Units that once covered base-load with almost 90% annual full-load operation may find themselves serving mid-load demand having much more demanding ramping behaviour (Brauner et al., 2012). Since flexible conventional power plants adapt to fluctuating demand during their operation, the realised dispatch and contributions to grid requirements determined by technical limitations have to be taken into account (Hobohm et al., 2012). The future profitability of conventional power plants has been subject to various studies in the last years. Blyth et al. (2007) examines investment uncertainties under climate conversion goals and evaluates investments in new conventional units, neglecting dynamics in electricity prices and the effects of increased operational flexibility. Deng et al. (2005) models conventional generation units' operational constraints and evaluates the influence of spot price spikes on their economic value. Operational characteristics are as well incorporated in the model proposed by Deng and Oren (2003), calculating units' projected cash flow considering the resource portfolio and the forecasted load. Though, production costs do not take into account the price of CO_2 and cannot provide insight into the future of conventional generation under climate conservation policy. This article presents a tool, that has been created for engineers and stakeholders who want to relate efforts in increasing conventional power plant flexibility to a monetary advantage. Operational flexibility characteristics such as minimum load, load-dependent efficiency and start-up differentiation are considered together with electricity and CO_2 prices for four types of generation units. The presented results are based on PHELIX 2014 price data for the German electricity market (European Energy Exchange, 2014).

2. Monetary evaluation of conventional power plant flexibility options

Germany's electricity sector strategies are closely associated with the climate conservation plans of the European Union (EU). EU states are obliged to reduce CO_2 emissions by 20% by 2020 with

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Table 1
Flexibility and start parameters for conventional power plants (Brauner et al., 2012; Kumar et al., 2012; Lindsay and Dragoon, 2010).

Power plant type		Hard coal	Lignite	CCGT	GT
Minimum load	($\%P_n$)	20–40	40–60	30–50	20–50
Ramp rate	($\%P_n/min$)	1.5–6	1–4	2–8	8–15
In load range	($\%P_n$)	40–90	50–90	40–90	40–90
Start-up time	(h)				
Hot	(<8 h)	1–3	2–4	0.5–1.5	<0.1
Warm	(8–48 h)	3–6	4–7	1–2	<0.1
Cold	(>48 h)	4–10	6–10	2–4	<0.1

respect to 1990 levels and to increase the share of RE by 20% (Commission of the European Communities, 2008). Germany's energy policy extends these CO_2 reduction targets to 80% by 2050 (Bundesnetzagentur and Bundeskartellamt, 2014; Bundesregierung, 2013). In the first two quarters of 2014, Germany produced 30.8% of its overall generated electricity from RE (Burger, 2014). The most important sources were photovoltaic and wind turbines, generating 55% of all RE (Weale and Roth, 2013). Their increasing capacity has implications for the position of conventional production capacities (Brauner et al., 2012):

Nuclear power plants

In Germany, concerns about the safety of nuclear reactors increased after the Fukushima nuclear accident in 2011. By 2012, 8.4 GW of nuclear power had been phased out under an amendment to the German Nuclear Power Law (Bundesnetzagentur and Bundeskartellamt, 2014). Phase-out of nuclear plants is scheduled to be finalised by 2022. Nevertheless, nuclear power contribution to the gross electricity generation (GEG) in Germany was at 14.1% in 2015 (Bundesministerium für Wirtschaft, 2015).

Coal power plants

Coal units serving base- and mid-load dominate the power generation at the moment, with the purpose of providing customers with supply security. Coal-fired units are subdivided by fuel into lignite and hard coal units. The share of GEG for 2015 was at 24.0% for lignite and 18.2% for hard coal power plants (Bundesministerium für Wirtschaft, 2015). The low price of carbon certificates and domestic lignite reduces the variable cost of electricity from lignite power plants and gives them a favourable position in the merit order.

Gas power plants

Germany's natural gas plants were designed to cover mid- and peak-load and hold 8.8% of the GEG for 2015 (Bundesministerium für Wirtschaft, 2015). Standalone gas turbines offer low efficiency but high operating flexibility (Deutsches Institut für Wirtschaftsforschung, 2013). They can be turned on to cover peak demand and they profit from high electricity prices. Combined-cycle gas turbines (CCGT) reach efficiencies up to 60%, and have been designed to cover mid-load demand. Due to high natural gas prices, these units are most likely to drop out of the market due to the merit order effect.

2.1. Conventional power plant flexibility options

Residual load shows a much wider spread and frequency of occurring load gradients with increased RE capacity (Brauner et al., 2012). This requires flexible operation of conventional capacities in terms of ramping events and start–stop regimes. Possibilities for flexible operation and optimised profits can be categorised into fuel and operational flexibility. These options are often interfaced and various implications need to be considered to adapt operation to the changing market. The degree of fuel flexibility is fixed to some extent for an existing power plant. In the course of this paper, fuel flexibility is therefore neglected. Operational flexibility refers to power plant dynamic behaviour, such as start/stop regime, minimum load, and ramping.

Start/stop regime

Starts are categorised into cold, warm, and hot based on the duration of the plant's standstill. Each type of start-up results in different capital and O&M costs due to fuel, chemical, and auxiliary demands. Different plant technologies imply different start procedures with different time spans and costs (Brauner et al., 2012; Kumar et al., 2012). Table 1 lists typical start durations for conventional power plant types. With a more pronounced start/stop regime, plant components suffer higher strains caused by uneven thermal expansions. This may lead to unplanned plant outages and needs for additional investments in unit revitalisation (Lindsay and Dragoon, 2010; Jeschke, 2013).

Minimum load

Minimum operating load is defined as the lowest safe and reliable power plant operation mode without the use of supplementary firing. Low load operation is characterised by worse relative emissions and efficiency, which both reflect negatively on the marginal cost of production. On the other hand, power plant operators can mitigate expensive start/stop procedures and keep the unit running at low load thereby minimising the monetary losses at non-optimal spread. In this way the plant is kept running and ready for quick residual load changes and is available to participate in the control market. New hard coal power plants have been designed to operate at low minimum load, reaching 20% of nominal power. Table 1 shows the minimum load for state-of-the-art technologies on the German market (Kumar et al., 2012; Lindsay and Dragoon, 2010).

Ramping

Power plant ramping refers to a load-following operation regime, in which a unit's generation changes from maximum to lower or minimum load. The rate of change of plant load is called ramp rate (RR). A power plant's potential for meeting fluctuating demand grows with higher ramp rate.

3. Power plant valuation tool methodology

3.1. Methodology and structure of the valuation tool

For a straightforward evaluation of technical improvements or purchase price changes from an engineering perspective, the valuation tool is based on the plant position on day-ahead and

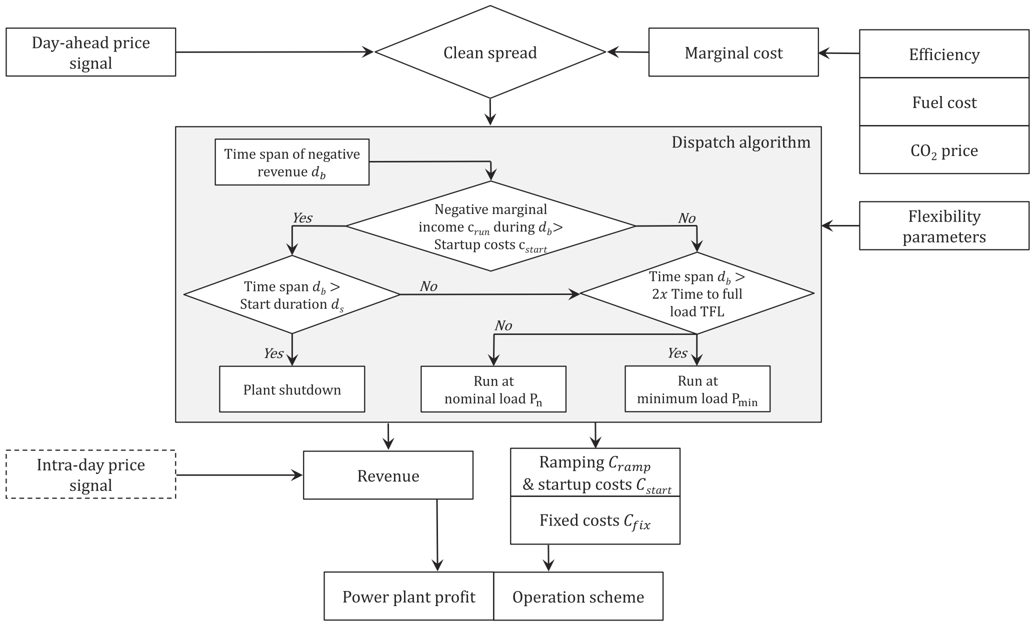

Fig. 1. Flow chart of power plant valuation tool with algorithm for power plant dispatch.

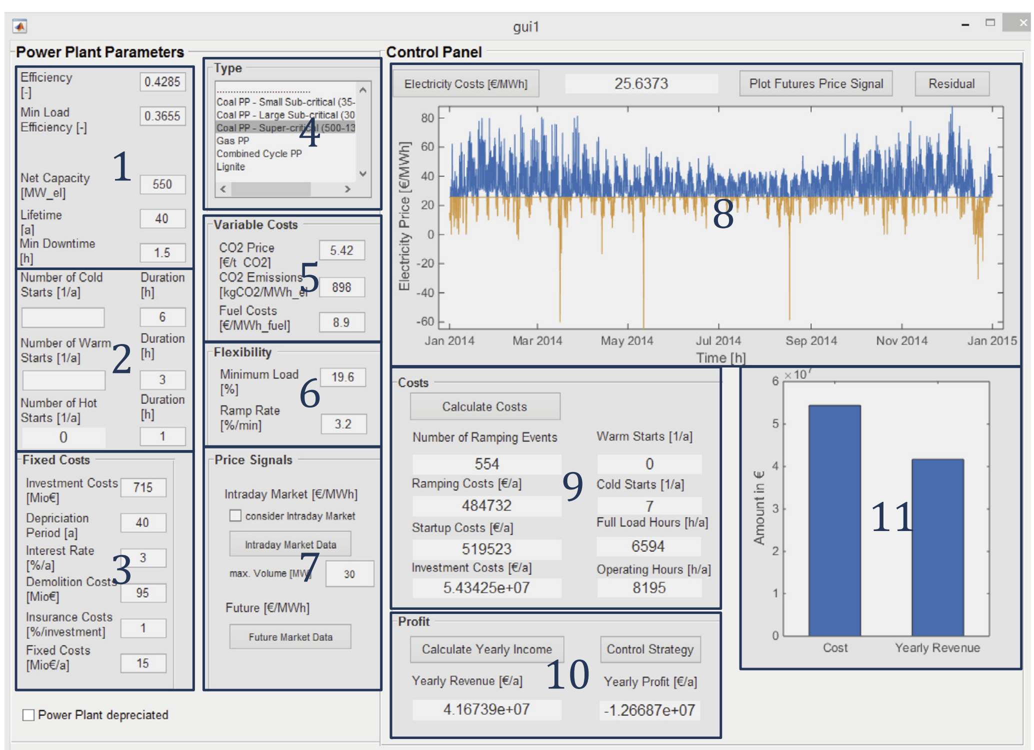

Fig. 2. Structure of the valuation tool user interface with sections 1–11.

intra-day markets. It utilises user-defined price signals of both and compares the plant's generation prices in order to calculate yearly expenditures and profits as well as a preliminary operating scheme (see Fig. 1). Though, valuation in the intra-day market is optional. After the data has been fed to the program, the monetary plant valuation consists of the following steps:

1. Marginal cost calculation.
2. Building intersection between price signal and marginal cost.
3. Determination of optimal dispatch scheme.
4. Determination of the number of ramping events and hot start-ups.
5. Comparison of yearly cost and profit.

A graphical user interface visualises plant parameters' effects on the output. The tool is structured into eleven different functional sections, shown in Fig. 2.

Section 1 specifies the input of technical power plant parameters. Section 2 handles the start-up regime of the tested site. Inputs are start-up durations and the yearly amount of planned cold and warm starts. The number of hot starts is determined based on

Table 2
Basic plant parameters used for reference calculations and validation (knoema, 2015a,b).

Parameter	Hard coal:	dep.	600 °C	Lignite:	dep.	CCGT:	Gas:	dep.
Nominal efficiency (%)	42.9	42.9	46.3	38.9	38.9	57	39	39
Part load efficiency (%)	36.6	36.6	43.2	32.5	32.5	49	32	32
Minimum load (%)	19.6	19.6	19.6	40	40	45	45	45
Ramp rate (%/min)	3.2	3.2	4	2.5	2.5	6	10	10
Minimum downtime (h)	1.5	1.5	1.5	1.5	1.5	0.5	0.25	0.25
Emission factor (kg CO_2/MWh_{el})	898	898	898	1062	1062	398	544	544
Net capacity (MW_{el})	550	550	911	944	944	845	415	415
Investment cost (€/kW)	715	–	1184	1400	–	590	250	–
Fuel price (€/MWh)	8.9	8.9	8.9	2	2	27.6	27.6	27.6
dep. = depreciated								

plant dispatch as an output of the relation between plant's running costs and the price signal. Section 3 includes financial aspects relevant for the calculation of fixed costs as input. The tool handles capital coming from loans, discounted by a interest rate to a set of yearly payments. Beside investment costs, non-fuel O&M, and insurance are handled in section 3. Depreciated power plants can be considered by eliminating capital costs from the yearly profit calculation. In this case, only insurance and non-fuel O&M costs are considered as fixed costs. In section 4 conventional power plant types can be chosen via list menu. The chosen type determines unit start-up costs relevant for total cycling costs, based on empirical data (Kumar et al., 2012). Section 5 provides variable costs, such as fuel price, CO_2 certificate price and emission factor. These parameters are used for the calculation of clean spreads (see Eqs. (6) and (7)) and the plant's marginal costs (see Eq. (1)), which determine its market position. Section 6 specifies flexibility parameters as ramp rate and minimum operational load. Section 7 handles the chosen price signals for day-ahead and intra-day prices as well as a optional marketing volume on the intra-day market. Section 8 displays calculated generation costs based on inputs from section 1 and 5 and visualises the price signal. Marginal costs of electricity split the price curve in two, whereas the blue part above the marginal price represents the plant's revenue and gives first insight of the market position. Section 9 shows calculated yearly investment, ramping and start-up costs. A comparison between yearly costs and income is shown in section 10 and 11. A generation dispatch scheme derived from the interaction between market price, marginal costs, cycling costs and technical constraints.

Dispatch algorithm

To determine operator's responses to unfavourable market conditions, the dispatch algorithm shown in Fig. 1 is used to put blocks of negative revenue hours through a set of logical tests, determining adequate action and maximising plant revenues. The dispatch algorithm counts ramping events and classifies operating state changes, resulting in an hourly operating scheme defined with three operational modes represented by h_i. Fig. 5 shows an operating scheme for a supercritical 550 MW hard coal power plant during March 2014 with parameters from Table 2 and variable cost C_{var} of 25.6 €/MWh.

$$h_i = \begin{cases} 1, & \text{Plant at full-load } \blacksquare \\ 0, & \text{Plant at minimum load } \blacksquare \\ -1, & \text{Plant at shutdown } \blacksquare. \end{cases}$$

Marginal cost

Variable costs of power plants include expenditures accruing from the production of a unit of electricity. Units are ranked by lowest variable cost in the form of the merit order curve. Today, 90% of overall power plant revenues originate from the energy-only market. Introducing a large RE capacity leads to the merit order effect (Sensfußet al., 2007), which shifts the merit order curve to the right. This in turn leads to an overall electricity price reduction. It can be seen that the external factors influencing the marginal cost of electricity for a given power plant are fuel and CO_2 price (see Eq. (1)). Fuel costs are irrelevant to renewable generation but are of a crucial importance to conventional power plants. To assess the position of a thermal power plant on the market, it is necessary to see how these factors relate to the merit order curve ranking of units.

$$C_{var} = P_{fuel} \cdot hr + P_{CO_2} \cdot e. \tag{1}$$

Total yearly costs

Cost calculation is based on fixed costs, discounted to yearly values using annuity factors and yearly cycling costs (see Eq. (2)). Fixed costs reflect the unit's project investments, non-fuel operations, and maintenance O&M costs. Investment costs are essentially capital costs for construction, demolition, and technical equipment. Non-fuel O&M costs include costs of labour, direct material cost, marketing, and administrative costs. Annualised values represent a deterministic part of the power plant valuation and need to be covered by yearly profits. To convert fixed into yearly costs, investment and demolition costs need to be discounted with an interest rate. Assuming that total investment cost is loaned, yearly payments are calculated by multiplying investment cost with the annuity factor. Cycling costs originate from the power plant's operation plan. They are connected with plant flexibility and include ramping and start-up costs (see Eqs. (3) and (4)). Ramping costs are categorised as excess annual cost and cost per ramping event. Excess cost ExC occurs due to inability of a unit to instantaneously increase the load from minimum to maximum, resulting in positive and negative revenue contributions during a ramping event. The second part of total ramping cost comes from additional capital and O&M cost. To quantify these costs, empirical data from Kumar et al. (2012) is used. The number of annual ramping events N is counted using the calculated control scheme and multiplied with the cost per capacity for each event. Specific start-up costs increase with the duration of the previous shut-down. Due to the lack of accruing cost data, start costs in the valuation include only capital and O&M expenditures. Costs of additional start-up fuel, auxiliary power, water, and chemicals are not taken into account, because there is a lack of consistent information for some power plant types.

$$Cost = C_{fix} + C_{cyc} = C_{fix} + C_{ramp} + C_{start} \tag{2}$$

$$C_{ramp} = ExC_a + N \cdot P_n c_{ramp} \tag{3}$$

$$C_{start} = n_{hot} C_{hot} + n_{warm} C_{warm} + n_{cold} C_{cold} \tag{4}$$

$$C_{hot/warm/cold} = P_n c_{hot/warm/cold} \tag{5}$$

Revenue

The next step is the calculation of hourly plant revenues based on the dispatch scheme. Hourly revenues are summed for the valuation period to form the total revenue. Power plants selling

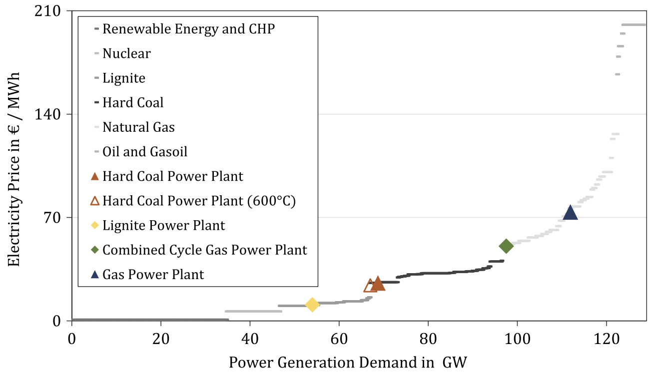

Fig. 3. Merit order curve with positioning of considered power plants for Germany 2014.
Source: Data for merit order curve extracted of source (Weale and Roth, 2013).

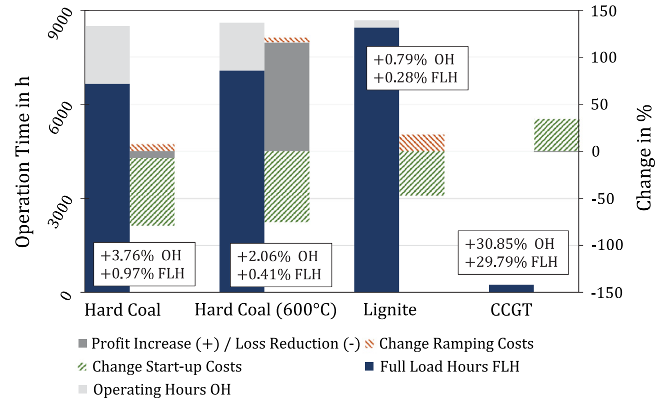

Fig. 4. Relative change of cost and profit with operation hours for reduction of minimum load by 50% for different types of conventional power plants compared to reference calculation based on day-ahead prices in 2014.

electricity at the market earn a gross equal to the spread. A positive spread with respect to market prices means, that the power plant is operating economically at a time. For countries covered by EU emissions trading schemes, generation units have to include the cost of CO_2 allowances in their spread. Therefore, the term clean spread is used when power plants' margins calculation include the emission cost. Clean spark spreads *CSS* and clean darks spreads *CDS* can be represented by Eqs. (6) and (7). However, this is not the net profit since it is used to cover the annualised fixed cost.

$$CSS = P_{el} - P_{gas} \cdot hr - P_{CO_2} \cdot e \tag{6}$$

$$CDS = P_{el} - P_{coal} \cdot hr - P_{CO_2} \cdot e \tag{7}$$

$$\text{Revenue}_i = \begin{Bmatrix} P_n \cdot CDS_i, & h_i = 1 \\ P_{\min} \cdot CDS_i, & h_i = 0 \\ 0, & h_i = -1 \end{Bmatrix}$$

3.2. Validation

The power plant valuation tool is tested and validated with a set of state-of-the-art power plants with parameters shown in Table 2. The position of these units in the German merit order curve is evaluated for 2014 based on PHELIX prices 2014 (European Energy Exchange, 2014). Average RE generation availability according to Weale and Roth (2013) is about 35.4 GW. This value is important for the validation, because prioritised RE generation moves conventional units to the right and makes them less profitable with the same demand. Certificate prices for CO_2 in 2014 were assumed as 5.42 €/t (European Energy Exchange, 2015). Fig. 3 shows a section of the merit order curve with a good fit of sites to their projected position, whereas modern plants with low marginal costs were considered for each type.

4. Results and discussion

4.1. Parameter study

The valuation tool was created to quantify the monetary effects of power plant dynamics. Since the flexibility of conventional units is an important topic in markets with high RE penetration, a parameter study is conducted to establish the monetary impacts of different flexibility options. After the initial valuation shown in Section 3, flexibility parameters are varied to determine whether they have a significant profit impact. Therefore, increased ramp rates and reduced minimum load as well as start-up times are examined. Furthermore, fuel and emission certificate prices are varied. Parameters are changed separately and impacts are measured through the relative change of operation hours, accruing costs and revenues from the futures market.

1. Increase of feasible ramp rates by 100%.
2. Reduction of minimum load by 50%.
3. Reduction of start-up durations by 50%.
4. Increase of CO_2 certificate prices to 10.03 €/t by 2020 (Schlesinger et al., 2014).
5. Increase of fuel prices by 2020.

4.2. Flexibility options evaluation

Observing the parameter study results, it can be seen that improved flexibility influences conventional power plant technologies differently:

Hard coal power plant

With current CO_2 and fuel prices, supercritical hard coal units using 600 °C-Technology operate with significant profit, whereas units with lower steam parameters struggle with balanced budgets, resulting of a decreased nominal efficiency. Increased ramp rates do not show a significant influence on the economic position of hard coal units on a day-ahead and intra-day basis. The proliferation of ramp rates leads to decreased ramping cost, but due to the very small share to the overall expenditures, there is no observable change in the net profit. Enhanced ramp rates decrease annual excess cost ExC_a due to imperfect dispatch (see Eq. (3)). However, the effect is only observable in case of a very high number of ramping events. Situation changes, as the minimum operational load is decreased (see Fig. 4). This triggers the dispatch algorithm to compare start cost with running ramped-down units during negative clean spread, resulting in proliferation of the number of ramping events and a decreasing number of hot starts. The unit's running cost at low load decreases, increasing the net profit. All hard coal power plants follow this pattern and have increasing profits on account of reduced start cost, reduced minimum load operation cost or a combination of both (see Table 3). A growth of load range does increase the ramping cost, but at a much lower magnitude compared to start cost mitigation along with reduction of annual losses. Lower minimum load also increases the number of operating hours, whereas full load hours do not rise equivalently. Nevertheless, with an increased amount of operation hours, the possibilities for offering control power and redispatch availability grow. 600 °C-Technology shows similar behaviour as other hard coal plants. Since there is broader scope for revenues with lower marginal cost in the merit order, profit increase is significant.

The operational scheme change is shown in Fig. 5. One week in August 2014 is illustrated with normal and reduced minimum operating load, whereas six periods of negative CDS are observable. With decreased minimum load, the loss of running the unit during

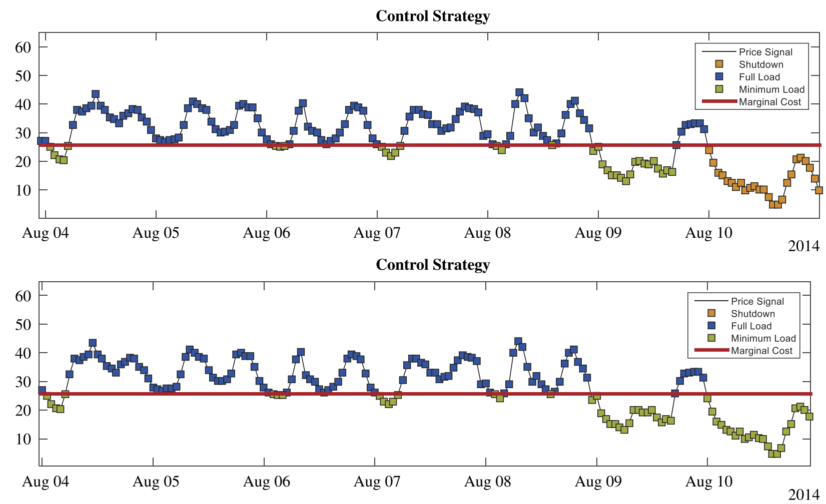

Fig. 5. Comparison of determined control strategies for state-of-the-art hard coal power plant (supercritical) with C_{var} of 25.6 €/MWh (Typical summer week 2014 without negative price signals); Upper image showing reference calculation; Lower image showing calculation with reduced minimum operational load.

Table 3
Parameter study results for conventional power plants with benchmark parameters in percentile change (%).

	Operating hours	Profit change	Ramping events	Ramping cost	Start-up cost
Increase of feasible ramp rates					
Hard coal	–	–	–	−0.98	–
Hard coal 600 °C	–	–	–	−0.64	–
Lignite	–	–	–	−0.41	–
CCGT	–	–	–	–	–
Reduction of minimum load					
Hard coal	+3.76	+7.11	+6.86	+7.49	−71.43
Hard coal 600 °C	+2.06	+115.56	+4.47	+4.87	−75.00
Lignite	+0.79	+0.25	+16.67	+17.63	−46.57
CCGT	+30.85	+0.85	+100.00	+100.00	+34.07
Reduction of start-up durations					
Hard coal	+3.76	+7.11	+6.86	+7.49	−71.43
Hard coal 600 °C	+2.06	+115.56	+4.47	+4.87	−75.00
Lignite	+0.44	−0.03	+9.52	+9.52	−17.81
CCGT	+30.85	+0.85	+100.00	+100.00	+34.07
Increase of CO_2 certificate prices					
Hard coal	−13.92	−122.27	+27.08	+26.94	+81.26
Hard coal 600 °C	−9.73	−3444.74	+38.62	+38.53	+117.21
Lignite	−1.47	−42.52	+211.90	+211.85	+14.02
CCGT	−23.94	−0.78	–	–	−17.81
Increase of fuel prices					
Hard coal	−14.68	−134.30	+28.88	+28.78	+91.10
Hard coal 600 °C	−9.73	−3523.74	+37.40	+37.34	+117.21
CCGT	−47.34	−1.74	+100.00	+100.00	−46.57

the night of August 10 does not exceed the cost of a start. The dispatch shows ramping and minimum load operation during the time the price drops below C_{var}. Shut-down becomes a more cost-effective option related to ramp-down as the number of negative-revenue hours increases. This behaviour changes due to increased costs incurred if start-up enters the warm or cold category. Due to limited amount of start-ups in the reference calculation, a reduction of start-up times by 50% has no measurable impact on revenues and operating hours. The impact is comparable to the values given for increased ramp rates.

Environmental requirements penalise conventional power plants with an increase of emission certificate cost (Graichen et al., 2014). It is therefore important to quantify the merits of flexible operation under such market conditions. A fuel price increase by 22% by 2020 is assumed to base on projections, because Germany depends on hard-coal and gas imports (knoema, 2015a). Supercritical hard coal power plants show more pronounced ramping behaviour in with increased CO_2 prices, leading to ramping cost increase. Fuel cost increase has the same impact with proliferation of ramping cost and ramping events. Therefore, hard coal units have to record substantially increased losses, with even 600 °C-technology falling into yearly minus. A proliferation of variable cost places these units in a similar dispatch as in Fig. 5 (upper image), but with longer blocks of negative CDS hours. Power plants also show the need to operate highly flexible during winter, because the marginal cost becomes greater than the price signal's minimum at that time. An increase in CO_2 and fuel costs influences the impact of improved operational flexibility. With increased amount of start and ramping events, flexibility options in this area become more important to the overall economic situation of hard coal units in terms of their share to the total yearly costs of the units.

Lignite power plant

Due to lowest marginal cost in carbon-based electricity production, lignite power plants serve base-load production with large amount of full load hours. Reinforced operational flexibility has no significant influence on the operational behaviour and profit of lignite power plants. With current CO_2 and fuel prices, they have a favourable market position without an enhanced need for flexible operation. Ramping situations are too few for ramp rate improvements to lead to net profit changes. For the reduction of minimum load, lignite power plants encounter similar responses as hard coal fired units. They see increased ramp cost, exceeded by savings in start cost. The impact compared to hard coal units is reduced, as lignite sites already have a high amount of operating hours in the reference calculation. Acceleration of start-up procedures slightly increases operating hours. Nonetheless, additional revenues are compensated by increased ramp cost. Isolated growth of CO_2 prices leads to a decrease in full load hours, together with a proliferation of ramping cost. Therefore, the net profit is reduced. Nevertheless, lignite units maintain their favourable position in the market with slightly reduced operating hours to 8490 h. Based on the occurrence of lignite in German deposits, the fuel price for 2020 is assumed to stay constant in relation to purchase prices for hard-coal and natural gas.

Combined cycle gas power plant

Improved operational flexibility has no measurable impact on the revenue of CCGT power plants. CCGT power plants hold an unfavourable position compared to other conventional technologies under consideration. With current CO_2 and gas prices, new CCGT operate with constant losses. Although this technology has the lowest investment and non-fuel O&M costs, revenue is not high enough for profitable operation, calling into question the sustainability of CCGT technology on the energy-only market with large capacities of other conventional sources. Because of fast load-changing capabilities, CCGT operation and net profit does not change with improved ramp rate and decreased start-up duration based on price signals with resolution of 15 min (see Table 3). Reduction of minimum load can lead to a slight improvement in the economic situation. However, the absolute value of 246 operating hours based on day-ahead market data is still far off design specification. As operation hours are limited, growing CO_2 prices have a limited influence on power plant expenditures and similar behaviour is observable for increased fuel price of 8.3% by 2020 compared to 2014 (knoema, 2015b).

Gas power plant

Standalone gas turbine units proved to be unsuitable for an evaluation based on day-ahead and normal intra-day exchange price data. The accessible data has a minimum resolution of 15 min, whereas this is to coarse for units to play off their ramping advantage. Gas Power Plants have already very high ramp rates and a decrease of minimum load would not make much difference to the revenue, because the positive CSS time periods are too far apart for the unit to ramp down instead of shutting down. Therefore, gas power plants monetary performance are not further examined for improved power plant flexibility on a exchange price basis.

5. Conclusions

To gain insight to the benefits of improved conventional power plants flexibility, an engineering-approached calculation tool has been developed. Results for PHELIX 2014 data show, that flexibility has a much more pronounced impact on coal plants. Hard coal and lignite power plants show an increase in net profit by operating with improved flexibility. CCGT plants show growing net profits only when conditions on the market caused by high CO_2 and fuel costs create an opportunity for them to become involved in ramping behaviour. The net profit increase is however marginal compared to coal units, because considered CCGT units already have fast ramp rates. The operation scheme is not characterised by enough ramping events and negative CSS operating hours for reduced minimum load to make any difference. Hard coal units are the cut-off technology for market participation and depreciated ones benefit more than new ones. Retro-fitting old power plants to achieve more flexible operation can extend their lifetime beyond the depreciation period. This strengthens profit opportunities and indicates the importance of incorporating flexibility into new hard coal power plant designs. Results show that reduction of minimum load leads to significantly greater increases of net profit than the improvement of ramp rates. However, plant values cannot be determined by exclusively observing exchange markets. Complete optional valuation would include other indicators such as industrial activity, revenues from co-generation of heat and power or revenues from the balancing market. Restructuring of the German electricity market, attention has to be paid to their currently questioned profitability as this encounters aspects as the feasibility of future's dreaming of a RE based energy consumption, not depending on conventional electricity imports of Germany's neighbours.

6. Nomenclature

Variable	Description	Unit
C_{cyc}	Cycling cost	€
CDS	Clean dark spread	€/MWh$_{el}$
$C_{hot}, C_{warm}, C_{cold}$	Total cost of start type	€
$c_{hot}, c_{warm}, c_{cold}$	Start-up cost per capacity	€/MW$_{cap}$
C_{ramp}	Total ramping cost	€
c_{ramp}	Specific cost of ramping event	€/MW$_{cap}$
CSS	Clean spark spread	€/MWh$_{el}$
C_{start}	Total plant start-up costs	€
c_{start}	Specific cost of start-up	€/MW$_{cap}$
C_{var}	Variable costs	€/MWh$_{el}$
d_s	Start-up duration	h
e	Emission factor	t_{CO_2}/MWh$_{el}$
ExC_a	Annual excess cost	€/a
hr	Heat rate	MWh$_{fuel}$/MWh$_{el}$
$n_{hot}, n_{warm}, n_{cold}$	Number of start-ups	–
P_{CO_2}	CO_2 certificate price	€/t_{CO_2}
P_{el}	Electricity price	€/MWh$_{el}$
P_{fuel}	Fuel price	€/MWh
P_n	Nominal load	MW
$P_{\min}$	Minimum load	MW

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