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Economics And Operation Of Fossil-Fired Power Plants In The German Electricity Market With High Shares Of Renewable Electricity Generation And Emission Trading Schemes

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Abstract

The increasing market integration of largely variable renewable electricity (RES-E) generation in the German electricity systems and the implementation of additional instruments to stabilize/reduce CO_2-emissions have a significant impact on the economics and operation of existing fossil-fired power plants. These new boundary conditions have a significant impact on investment decisions in case of repowering of existing and/or construction of new fossil-fired power plants. This paper analysis the future operation and the economics of fossil-fired power plants in the German case considering the age-structure of the German power plant portfolio, the significantly increasing deployment of variable RES-E generation, the potential of pumped hydro storage (PHS) to balance the system and ,finally, the economics of thermal power plant operation. The kernel of the economic analysis of future thermal power plant operation incorporates the parameters primary fuel prices, CO_2-emission price and the expected full load hours. The short-term power plant dispatch and long-term generation capacity planning analyses is based on a MATLAB-model. On the one hand this MATLAB-model evaluates the missing future gap on thermal generation capacity in Germany, taking into account already the increasing RES-E generation shares. On the other hand, an in depth evaluation is made in terms of the economic trade-offs of the three thermal power plant technologies lignite, coal and gas-fired combined cycle power plants (CCGTs). The modeling results clearly show that economics of fossil-fired plants increasingly is adversely affected in “energy-only” markets due to the “merit order effect” of RES-E generation (based on priority feed in). The economic trade-offs between the different fossil-fired power plant technologies are significantly dependent on the future scenario parameters like primary energy prices and CO_2 prices.

1. Introduction

Germany wants to achieve ambitious goals to significantly increase the deployment of RES-E generation [1]. Notwithstanding it is unavoidable also to build thermal power plants in the future. The limited life-time of thermal power plants, the nuclear phase out decision, the growing demand of balancing power and inherently scarce cross-border transmission capacities to neighboring countries [2-4] are the main reasons why thermal power plants still play an important role in the future German electricity generation system.

This paper analysis the future needs and the economics of thermal power plants under the aspect of significantly increasing RES-E generation in Germany; including the contribution of pumped hydro storage in Germany and its neighboring countries. The kernel of the economic analysis of future thermal power plant operation incorporates the parameters primary fuel prices, CO_2-emission price and the expected full load hours. Due to the nuclear phase out decision future nuclear power plants are not considered. For the economic analyses of future thermal power plants exclusively CCGTs, lignite and coal power plants are included in the scenarios analyses for the years 2020, 2030 and 2050. These analyzes are based on a MATLAB-model, which includes a short-term power plant dispatch on the one hand, and a long-term generation capacity planning on the other hand.

Figure 1 shows the age structure of the German thermal power plant-portfolio [5]. This figure includes all existing thermal power plants, those already in the queue and expected to online in the next couple of years and also those being decommissioned in the future. The installed capacities for gas and coal fired power plants will rise till 2015 because there are capacities still in construction progress whereas the capacities of lignite, oil and other thermal power plants will almost stay at the same level till 2015. Besides decommissioning of power plants in general, also the effect of the German nuclear phase out decision till 2022 can be observed in particular. Figure 1, furthermore, shows that the installed capacities of thermal power plants are less than 50% in 2050 compared to the level in 2015 in case no thermal power plants are assumed to be built in the future.

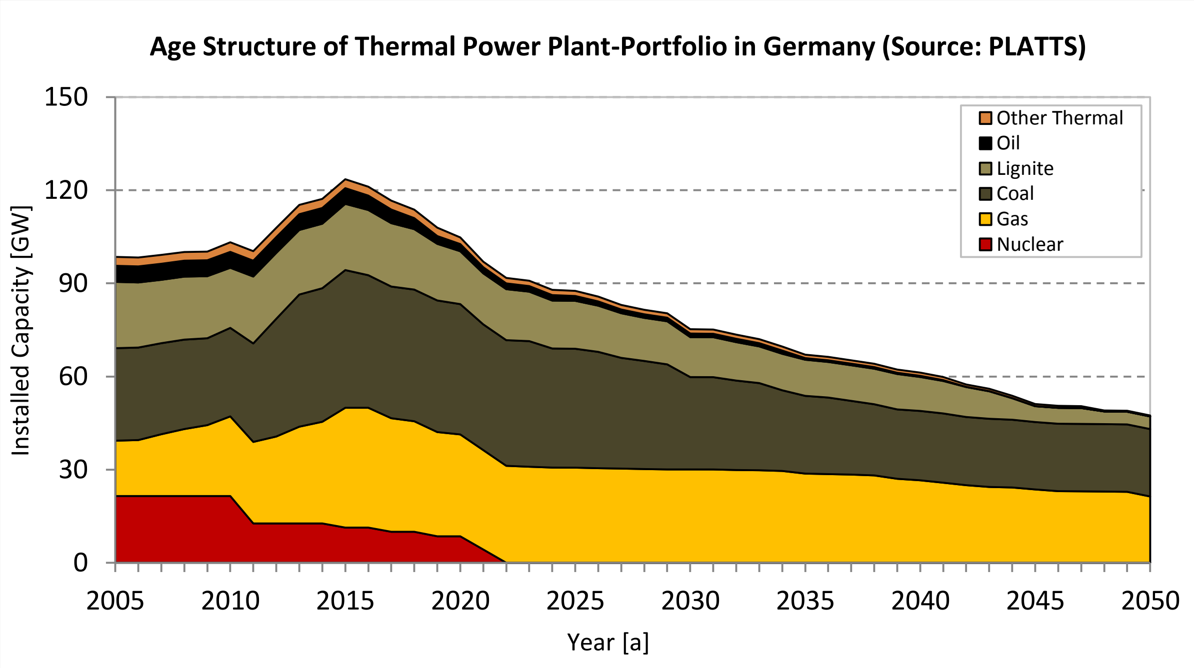

Figure 1: Age Structure of Thermal Power Plant-Portfolio in Germany

On the one hand, capacities of thermal power plants will decrease till 2050 unless there are no future decisions to build new thermal power plants. On the other hand, capacities for RES-E generation will significant increase in Germany, grounded on the ambitions RES targets [1]. The most promising contributions of RES-E potentials are PV and wind (onshore and offshore). An example on the influence of wind and PV generation on the German electricity system is shown in Figure 2, where the hourly German load profile and the "residual load curve" for month January 2010 is drawn. The black line describes the hourly load profile derived from ENTSO-E [6], the blue line shows the residual load profile where hourly wind and PV generation are already subtracted from the initial load profile. The most significant contribution of PV generation is at noon in the summer months. Electricity generation from wind turbines is higher in winter than in summer. In general wind and PV generation is very volatile, see Figure 2. In the first three days in January 2010 the contribution of wind and PV generation was insignificant, that means that nearly the whole demand was covered by other power plants. Some days show significant shares of PV and wind generation (e.g. January 5, 2010). In that case peak load is significantly smoothed by PV and wind generation. Another case illustrates that wind and PV generation decreases base load significant (see Figure 2 between 20th and 21st of January). In that case an option is to use pumped hydro storage (PHS) in the "pumping mode".

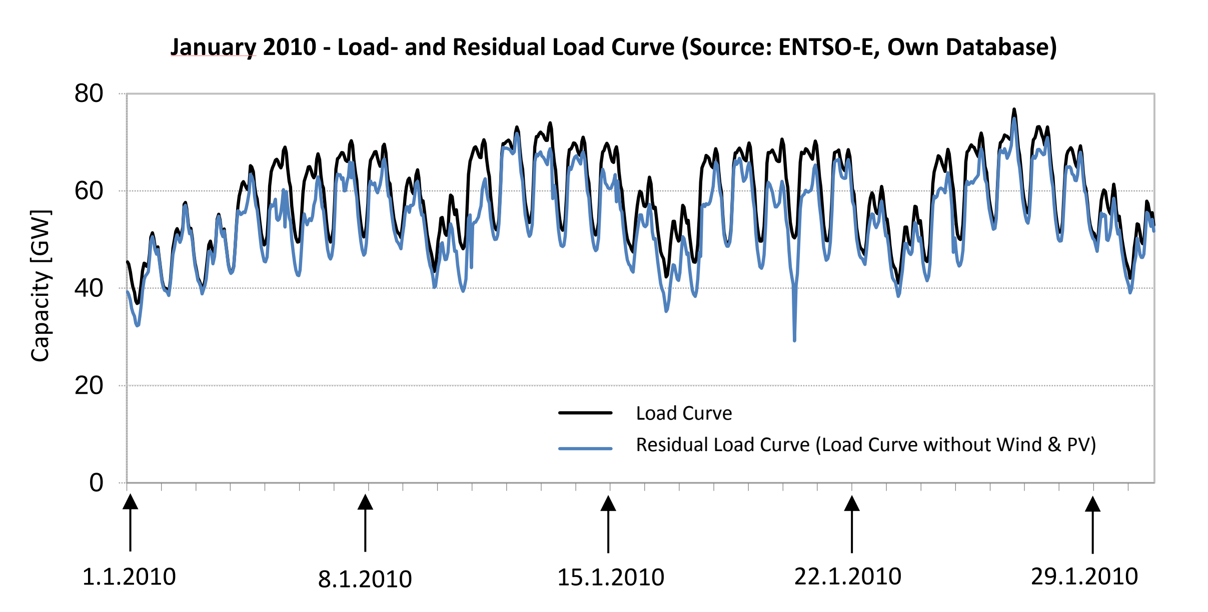

Figure 2: Load Curve und Residual Load Curve, Germany, January 2010

In Figure 3, the annual load profile and residual load curve are drawn as a duration curve for the whole year 2010. The load duration curve represents the yellow line in this figure. This load duration curve is the result of sorting the hourly based load profile per year downwards. In general, it is used for analyzing the maximum operation time for the different scenarios [7], [8].

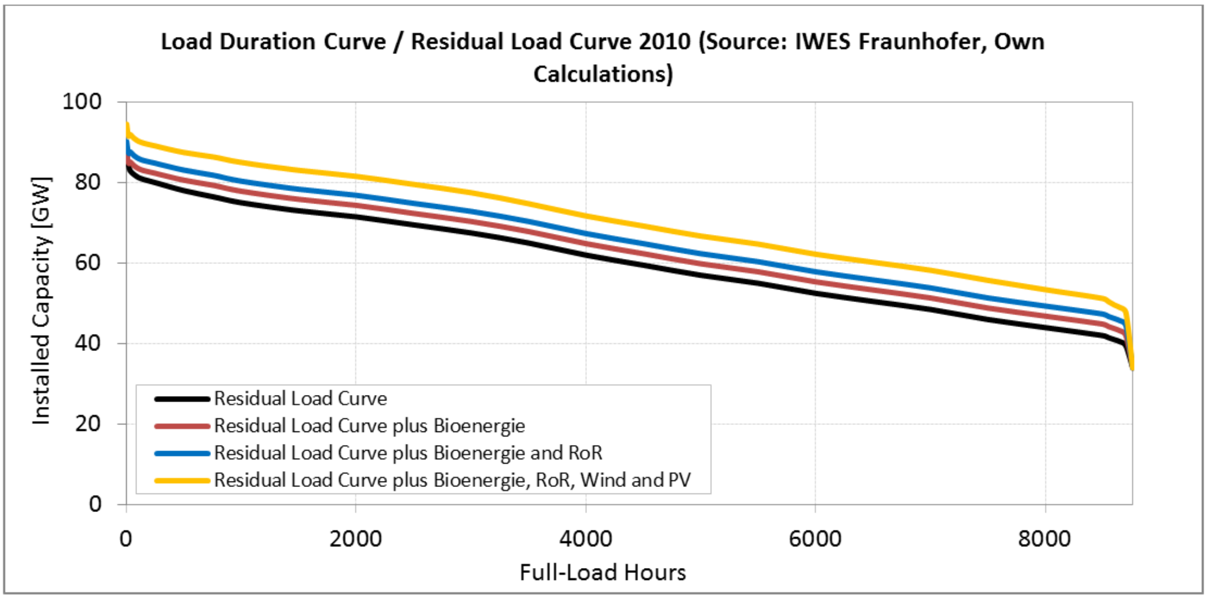

Figure 3: Load Duration and Residual Load Duration Curve, Germany, January 2010

The residual load curve (the black line in Figure 3), represents the hourly sorted load profile excluding load met by RES-Electricity generation. The lines between the load duration curve and the residual load curve show the shares of run-of-river (RoR) hydropower and bioenergy for electricity generation. Note, that after each removal of a respective RES-E generation profile the residual load curve is sorted again in a declining manner. This empirical part of the analyses is used to determine the expected full load hours of future power plants which is an important parameter for the economic analyses of these generation technologies.

2. Method of Approach

The method includes the short-term power plant dispatch in Germany, on the one hand, which focuses on the impact and the influence of PHS operation to the electricity system, and long-term generation capacity planning, on the other hand, grounded on the economics of future thermal power plant technology options in Germany. The method is implemented in a MATLAB-model. The corresponding flow process chart of the modeling approach is shown in Figure 4. Further explanations of the MATLAB-model details are given below.

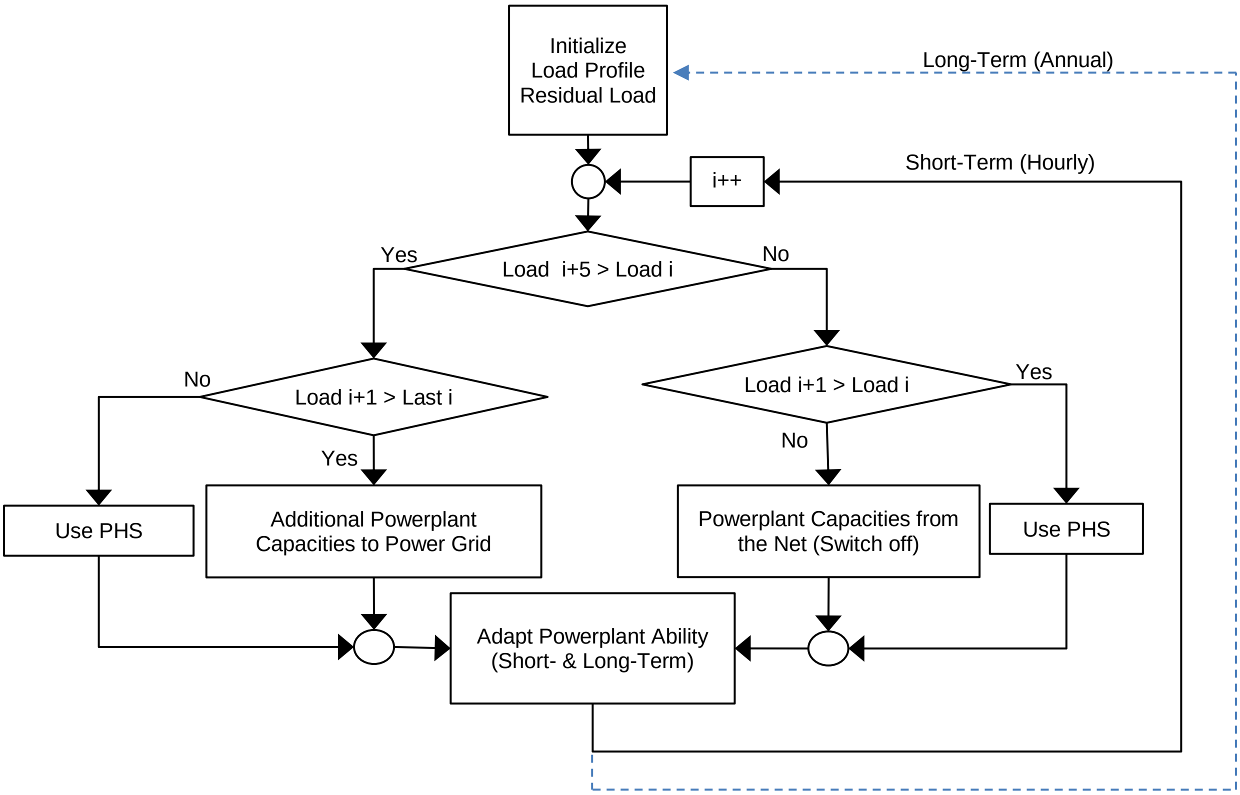

Figure 4: Flow Process Chart of the Model implemented in MATLAB

2.1 Short-term power plant dispatch

In the first step, the German load profile and the profile of priority feed-in of wind and PV generation is scaled up to the years 2020 and 2030. The German load profile is based on ENTSO-E data in 2010 and is scaled up with 1% increase per anno. The feed-in profile of wind and PV generation for 2010 and for different scenarios up to 2020 and 2030 is based on own data, see Table 1.

Installed Capacities in Germany in GW (Source: EEG Database)			
Year	2010	2020	2030
Wind Onshore	25.2	32.1	39.9
Wind Offshore	1.7	9.8	19.8
Wind Total	26.9	41.9	59.7
PV	14.6	23.2	28.4
PHS "Pumping"	7.9	8.7	8.7
PHS "Generating"	7.5	9.3	9.3
Run-of-River	5.3	5.6	5.6
Other Renewables	4.8	8.1	9.7

Table 1: Status Quo and Scenarios for RES-E generation in Germany in 2020 and 2030

Based on the hourly load profile and the hourly wind and PV feed-in profile the residual load, which also includes the feed-in of remaining RES-E generation technologies for 2020 and 2030 is created. The residual load curve for the year 2010 is already shown in Figure 2. The residual demand has to be covered by available thermal power plants scheduled based on a least cost power plant dispatch optimization. The start-up (warm start) and shut-down time for thermal power plants has to be considered when analyzing residual load coverage in order to consider the gradients of the volatile load profile correspondingly. The minimal operation time and the cool-down time have to be considered to keep the life time for the thermal power plants as high as possible. The corresponding values are shown in Table 2. Furthermore, also the seasonal variation of water levels of RoR power plants is considered in the full load hours. In the case of nuclear power the maximum full load hours are 7710h/a, meaning a capacity factor of 88%. Note, RoR and nuclear power plants are base load generation technologies being not switched off in low load periods.

	Start-up Time	Minimal Operation Time	Shut-down Time	Cool Down Time
	t_{on}	t_{min}	t_{off}	t_{cool}
Lignite and Coal	2h	3h	1h	3h
CCGT	1h	2h	1h	1h

Table 2: Dynamic Operational Parameters of Lignite, Coal and CCGT Power Plants (Own Data)

By covering volatile residual load, thermal power plants will only be switched on/off if the residual load will increase/decrease one hour and in 5 hours ahead. In that case it will be checked if load increases/decreases again in two hours. That is important in order to switch on/off power plants in time. If residual load is increasing/decreasing one hour ahead but decreasing/increasing 5 hours ahead PHS will be used to cover residual load. The analytical approach is given below and also shown in the flow process chart in Figure 4.

Main objective function $\quad min\ C_i$

Subject to: $\quad G_i \geq D_i$

Start-up $\quad z_{0,j,i} = z_{1,j,(i+ton)}$

$z_{1,j,i} = z_{1,j,(i+1)}$

Shut-down $\quad z_{1,j,i} = z_{0,j,(i+tcool)}$

$z_{0,j,i} = z_{0,j,(i+1)}$

Minimal operation $\quad z_{0,j,i} = z_{0,j,(i+ton+tmin+toff)}$

Cooling down $\quad z_{1,j,i} = z_{1,j,(i+toff+tcool+ton)}$

C_i Marginal Generation Costs at the Hour i
G_i Generation in Hour i
D_i Demand in Hour i
$z_{j,i}$ State of Thermal Power Plant j in Hour i (1 = on; 0 = off)

Table 3 illustrates an example for switching-on and off a coal-fired power plant.

		i	i+1	i+2	i+3	i+4	i+5	i+6	i+7	i+8	i+9	i+10	i+11
Coal	z	0	0	0	1	1	1	1	1	1	1	0	0
	t_{on}	2	2	1	0	0	0	0	0	0	0	2	2
	t_{min}	0	0	0	3	2	1	0	0	0	0	0	0
	t_{off}	0	0	0	1	1	1	1	1	0	0	0	0
	t_{cool}	0	0	0	3	3	3	3	3	2	1	0	0

Table 3: Example for Start-up, Minimal Operation, Shut-down and Cooling-down of a Coal Power Plant

At time i the power plant is offline (z=0). If capacities are needed because demand is rising in i+1 and i+5, the switch-on process must begin. The start-up time is 2 hours, meaning that capacity is available in i+3 (z=1) and remains at least until i+6 (due to the minimal operation time of 3 hours). In this example the shut-down process is initiated in i+7 and ends in i+10. The reason for this delay is the cooling-down time. Beyond that point in time, the power plant is inactive again (z=0).

2.2 Long-term generation capacity

In a second step, the method analyzes the economics of thermal power plants having to be built in Germany in the future. Therefore, the residual load duration curves have to be drawn for the years 2020, 2030 and 2050 [7-8]. The residual load duration curve for the year 2010 is already presented in Figure 3. The next step is to fill up these residual load curves with the capacities of existing thermal power plants [5][1], see in Figure 5 below for the year 2030.

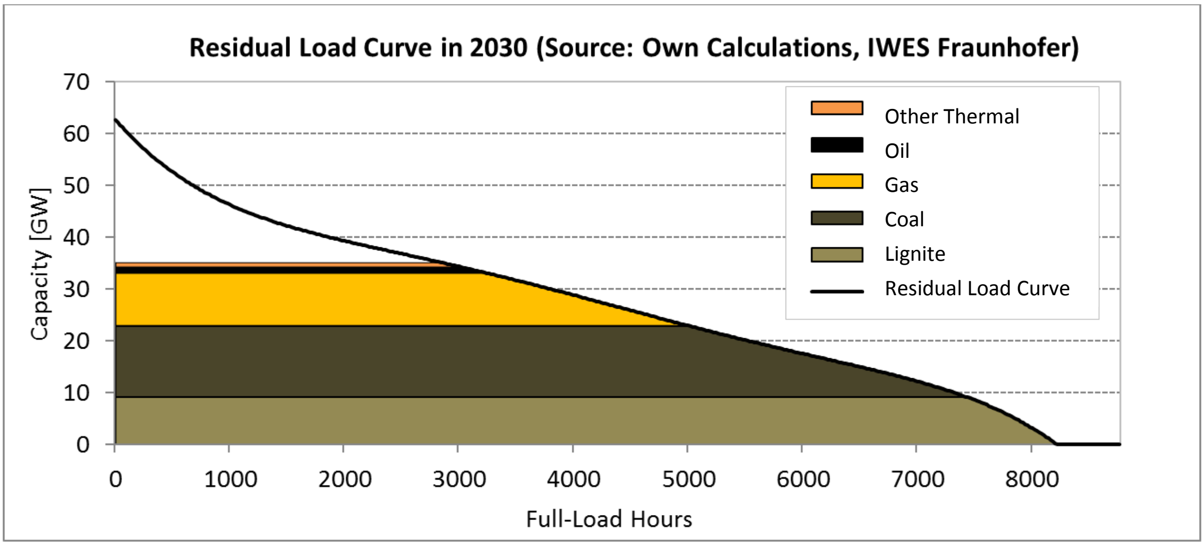

Figure 5: Residual Load Curve in 2030

The white area shows the missing gap between flexible generation capacities and load in Germany in 2030. It can be covered by imports, or by building new thermal power plants (CCGT, lignite or coal) and/or if there are potentials available PHS power plants. The following economic analyses are based on least-cost capacity planning for the German power plant system. Beside primary energy prices and CO_2-Certificate prices the expected full-load hours are the most important parameters in the economic trade-off analyses.

Using the long-term marginal generation costs as an economic decision criterion, borderslines between each pair of technologies are determined. The mathematical expression of the long-term marginal generation costs is shown below:

$$C_{el} = C_{FIX} + C_{VAR} = \frac{\alpha * C_{INV}}{T_{el}} + \frac{C_{FUEL}}{\eta_{el}} + \frac{C_{O\&M}}{T_{el}} + C_{Cert}\frac{E_{CO2}}{\eta_{el}}$$

The economic borderline between two technologies is calculated by equalizing the long-term marginal costs of one technology (e.g. CCGT) with another technology (e.g. lignite). This calculation is done for each pair of the three technologies. As a result of this approach three economic borderlines are calculated.

C_{el}…	Long-Term Marginal Generation Costs [€/MWh]	C_{Fuel}…	Costs of Primary Fuel [€/$MWh_{primär}$]
C_{FIX}…	Fixed Costs [€/MWh]	η_{el}…	Electrical Efficiency [1]
C_{VAR}…	Variable Costs [€/MWh]	$C_{O\&M}$…	Costs of Operations and Maintenance [€/kWa]
α[2]…	Annuity Factor [1]	C_{CERT}…	CO_2- Certificate Price [€/tCO_2]
C_{INV}…	Specific Investment Costs [€/kW]	E_{CO2}…	Specific CO_2-Emissions [tCO_2/$MWh_{primär}$]
T_{el}…	Full-Load Hours (electrical) [h/a]		

[1] The capacities shown per power plant technology already take into account average maintenance periodes where capacities are offline.

[2] $\alpha = \frac{z*(1+z)^n}{(1+z)^n-1}$ z… Interest Rate [%] n… Economic Life-Time [a]

The primary fuel price scenarios for coal and lignite are assumed to increase slowly over the next decades. Due to the fact that future gas prices are afflicted by high uncertainty, they are assumed as a variable parameter in the economic analyses. This assumption refers also to relevant German studies [9-11]. The parameter settings for the economic analyses are shown in detail in the appendix.

3. Results

In the following, results of the short-term power plant dispatch are discussed in detail for the scenario analyses January 2020 and January 2030. The corresponding results of July 2020 and July 2030 are shown in the appendix. The long-term generation capacity planning results including the economic analyses is discussed for the scenarios 2030 and 2050. Note, that this paper does not analyses the economics of pumped hydro storage; however the economics of the thermal power plants can be interpreted also as a benchmark for future PHS development.

Figure 6 illustrates the result of the short-term power plant dispatch in January 2020, where the residual load curve (without wind and PV) has to be met based on the least-cost principle [12]. The solid black line in Figure 6 indicates the ceiling of several activated generation capacities without PHS. Several activated generation capacities are filled up in a merit order. The remaining gap needs to be filled up by PHS. The profile of PHS operation needed is drawn separately as a solid blue line. A positive value of the blue line indicated the generating-mode whereas a negative value means pumping. In Germany, installed capacity of PHS is assumed to be 9.3GW in 2020. This, however, is not enough to meet peak load (cf. Figure 6). Therefore, additional PHS capacities have to be imported from Austria, Switzerland and/or Scandinavia. In addition, however, there are also possibilities to cover the entire residual load with new thermal power plants (lignite, coal, CCGTs). The first approach is to build further lignite or coal fired power plants to cover the base load, so that existing PHS and CCGT could be used for covering the whole peak load.

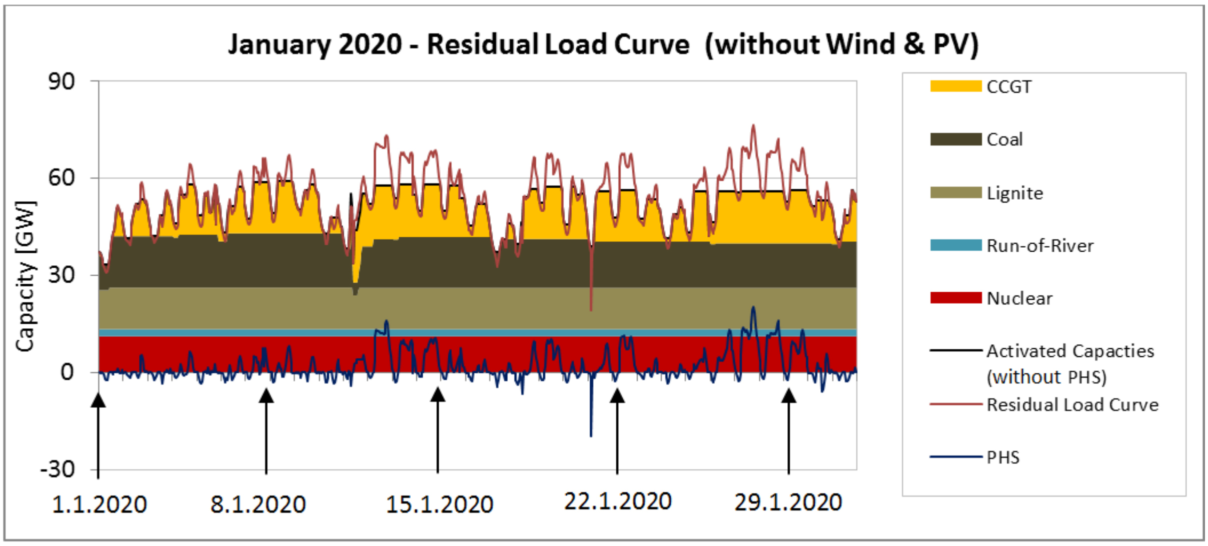

Figure 6: Residual Load Curve, January 2020, with thermal power plant dispatch and possible contributions of PHS generation

Looking one decade ahead, the scenario January 2030 (cf. Figure 9 in the appendix) obviously calls for the future need of significant capacities. Moreover, the installed generation capacities of the German power plant portfolio further decrease until 2030. On the contrary, the deployment of wind and PV capacities further increases significantly until 2030 (see also Table 1). Figure 7 again illustrates the theoretical operation of PHS generation (blue line). Theoretically up to 30.3 GW of PHS capacities would be needed in the generation-mode and 28 GW in pumping-mode. However, in practice installed capacities of PHS in Germany in year 2030 only is 8.7 GW (pumping-mode) and 9.3 GW (generating-mode). Therefore, additional thermal power plants have to be built.

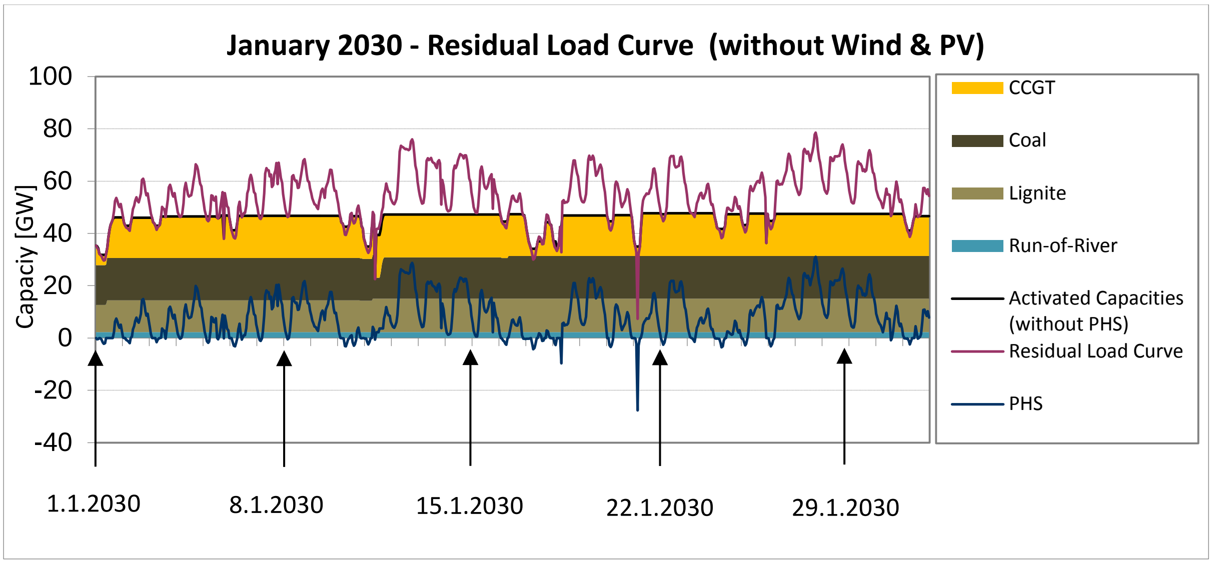

Figure 7: Residual Load Curve, January 2030, with Thermal Power Plant Dispatch and the theoretical Contribution of PHS generation

One of the most important results (shown in Figure 7) is the fact that there is no equilibrium between generating and pumping mode. This means that PHS is nearly always used in the 2030 "thought experiment" in the generation-mode. In practice, the energy storage capacity of PHS is limited and cannot be managed according to the blue line indicated in Figure 7. Please note, that also imports of PHS from neighboring countries cannot follow the significant imbalance between generation and pumping.

When considering additional thermal power plant capacity planning in the long-term [13], the situation is as follows: on the one hand, Figure 8 shows the residual load curve and the still existing thermal power plants, on the other hand, the economic borders between the different thermal power plant technologies for the scenario 2030 based on a gas price of 20€/MWh. The lower part of Figure 8 is already presented and discussed in Figure 5, here in Figure 8 it is just plotted mirrored on the horizontal axis.

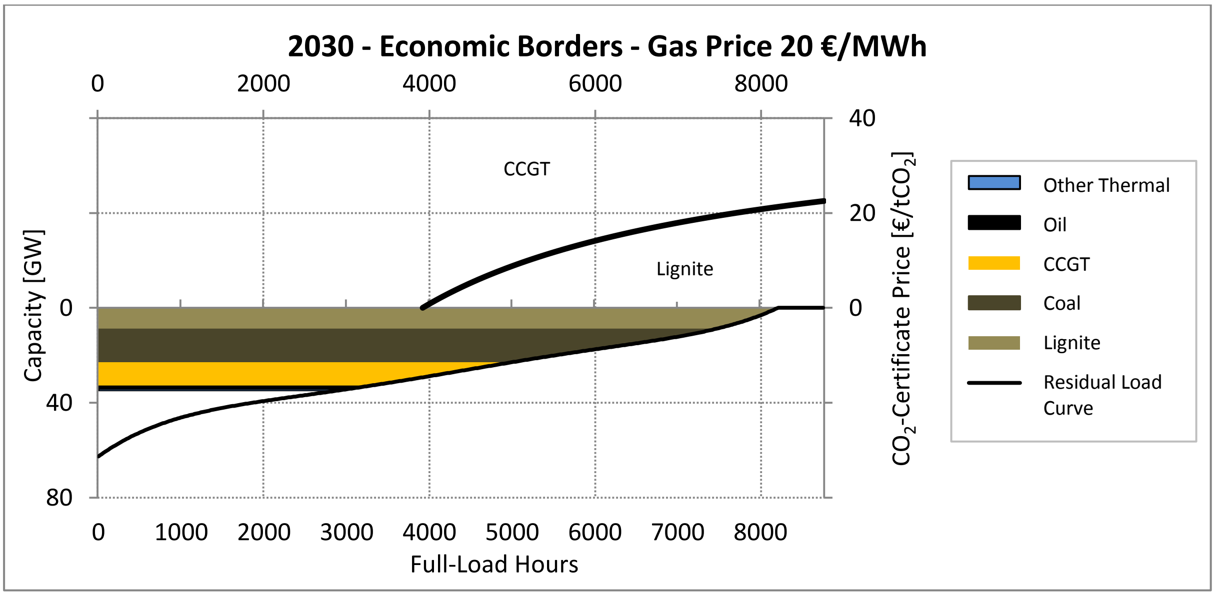

Figure 8: Economic Borders between the different thermal generation capacities, Germany 2030, Gas Price 20€/MWh

The withe area in Figure 8 largely needs to be filled up with new thermal power plants. The missing generation capacity is about 30GW and the maximum expected full load hours of additional capacities needed is only about 3000h/a. The upper part in the figure illustrates the economic border between CCGT and lignite. Coal-fired power plants are not economic over the entire range of full-load hours and CO_2-certificate prices (assuming gas price scenarios of 20€/MWh and using parameter settings according to the appendix). In the bigger area new CCGT power plants are more economic than lignite. Moreover, for CO_2-Certificate prices above 22€/tCO_2 CCGT power plants will always be more economic than lignite. For CO_2-Certificate prices below 22€/tCO_2 the economics of these technologies depends on the full-load hours, see Figure 8.

The results of the economic analyses for a gas price of 40€/MWh is illustrated in Figure 9. The lower part of the figure is the same compared to Figure 8. The economic borders now split the solution space in three economic areas in the upper part of Figure 9. In case of a future gas price of 40€/MWh all three thermal generation technologies are economic for specified couples of full load hours and CO_2-certificate prices. E.g., for a future CO_2-Certificate price of 30€/tCO_2 there are two possible power plant technologies competing against each other. On the one hand, CCGT power plants for less than 2200h/a full-load hours and, on the other hand, lignite power plants above. Assuming a future CO_2-Certificate price of 60€/tCO_2 CCGT will always be the most economic technology. Future coal-fired power plants are only for a few couples of parameters (e.g. gas price 45€/MWh and 2900h/a full-load hours) the most economic choice. Note further, that parameter couples near the economic border line of the CCGT area in case of doubt, decisions should be made in favor of CCGT (due to higher flexibility).

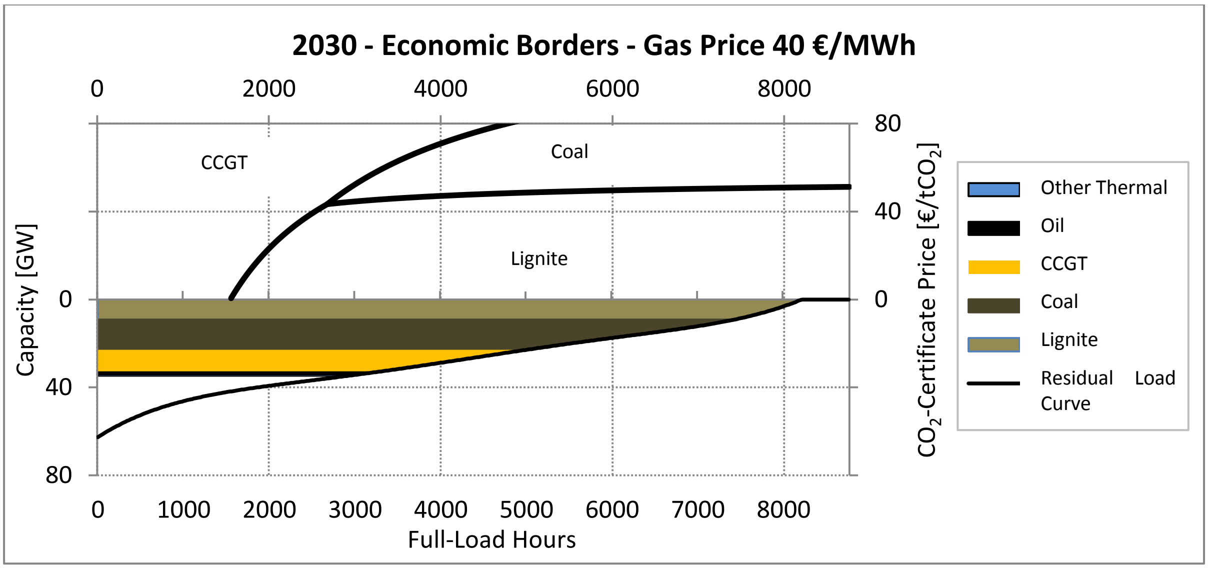

Figure 9: Economic Borders between the three competing thermal power plants, Germany 2030, Gas Price 40€/MWh

Figure 10 illustrates the result for the 2050 scenario with a gas price of 60€/MWh. The gap of additional generation capacity needed increases to about 40 GW in 2050 (compared to 30GW in 2030). The maximum operation time of missing power plants capacities reaches 4500h/a. Figure 10 generally shows that the CCGT technology is the most economic technology for low full load hours. The economic borders between CCGT and the remaining technologies are significantly shifted left compared to the previous case in 2030. This means, that the CCGT-technology is the most economic technology for low full load hours (smaller than 1300h/a). The economic border between lignite and coal approximately is a horizontal line. For CO_2-Certificate prices above 45€/tCO_2, a lignite-fired power plant is less economic than a coal-fired power plant for full-load hours above 1300h/a.

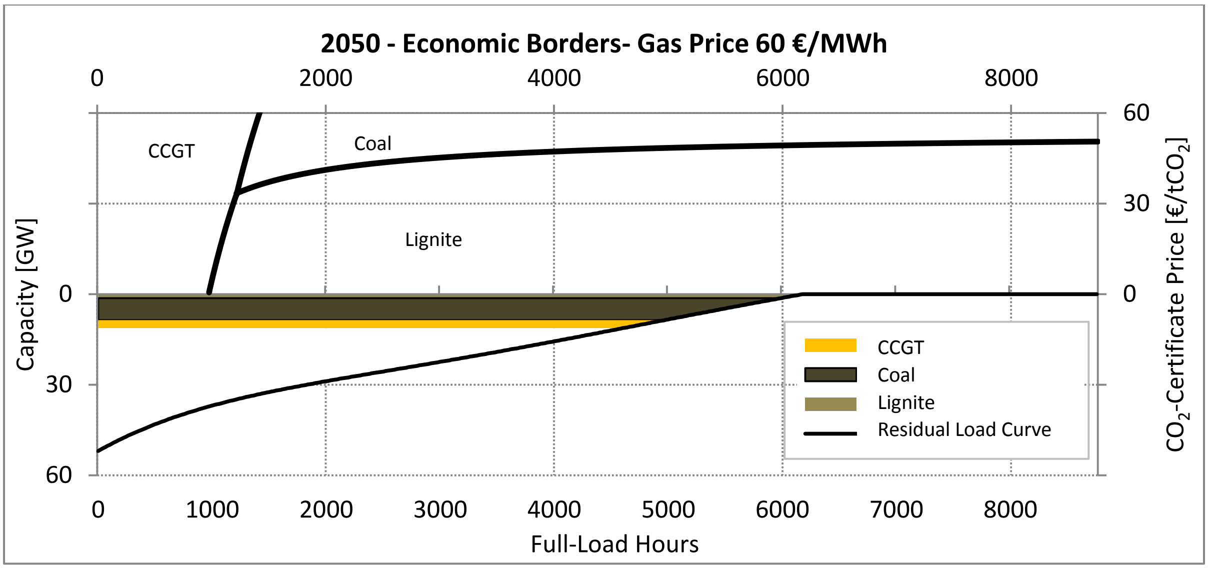

Figure 10: Economic Borders between the three competing thermal power plants, Germany 2050, Gas Price 60€/MWh

4. Conclusions

The analyses in this paper clearly show that there is a future need of thermal power plants in Germany, although the generation capacities of RES-E generation will rapidly increase. The significant increase of volatile RES-E generation has a significant impact to maximum operation time of already existing thermal power plants. The reduction of the full load hours of thermal power plants again has a huge impact to the economics of these power plants.

Thermal power plants are qualified to deliver flexibility for balancing the electricity system (due to their high power gradient). It is a matter of fact that CCGT power plants can start-up very quickly, but also future coal and lignite power plants have a high power gradient for balancing stressed electricity systems. This paper shows that the economics of future thermal power plants mainly depends on future gas- and CO_2-certificate price scenarios. In the border case a decisions should be taken favoring CCGT power plants. Not only due to their higher flexibility but also due to the fact that there are many cases where they are the most economic technology (compared to coal or lignite).

The economics of the thermal power plants is also a benchmark for future PHS capacity planning and operation. New PHS plants only can be built in specific regions, e.g. the Alps or Scandinavia whereas thermal power plants could be built where they are needed (in case of getting the permissions). Another fact is that the potential of new PHS is limited both in terms of capacity and the energy content. The missing gaps of the German energy system illustrated in the different figures of this paper cannot be covered only by PHS-imports due to the limited cross boarder transmission capacities.

Beside the fact that more flexible power plants are a need of a future electricity system the paper also shows that guaranteed capacities will more important in the future. In the case of intraday markets future PHS and biomass-fired CHPs have limited potentials, whereas thermal power plants are not restricted in general.

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Appendix

Parameter-Settings 2020		Lignite	Coal	Gas
Specific CO_2-Emissions	[t-CO_2/$MWh_{primär}$]	0.396	0.342	0.198
Investment Costs	[€/kW]	1100	950	400
Fuel Price	[€/$MWh_{primär}$]	5	9,69	Variable
Electrical Efficiency	[%]	46	49	60
Costs for O&M	[€/kWa]	34	45	17
Interest Rate	[%]	8	8	8
Depreciation Period	[a]	20	20	20
Annuity Factor	[1]	0.1019	0.1019	0.1019

Table 4: Parameter-Settings 2020

Parameter-Settings 2030		Lignite	Coal	Gas
Specific CO_2-Emissions	[t-CO_2/$MWh_{primär}$]	0.396	0.342	0.198
Investment Costs	[€/kW]	1060	900	400
Fuel Price	[€/$MWh_{primär}$]	5.25	10.52	variable
Electrical Efficiency	[%]	46,5	50,5	61
Costs for O&M	[€/kWa]	34	45	17
Interest Rate	[%]	8	8	8
Depreciation Period	[a]	20	20	20
Annuity Factor	[1]	0.1019	0.1019	0.1019

Table 5: Parameter-Settings 2030

Parameter-Settings 2050		Lignite	Coal	Gas
Specific CO_2-Emissions	[t-CO_2/$MWh_{primär}$]	0.396	0.342	0.198
Investment Costs	[€/kW]	1050	900	400
Fuel Price	[€/$MWh_{primär}$]	5,5	10,9	variable
Electrical Efficiency	[%]	47.5	52	62
Costs for O&M	[€/kWa]	34	45	17
Interest Rate	[%]	8	8	8
Depreciation Period	[a]	20	20	20
Annuity Factor	[1]	0.1019	0.1019	0.1019

Table 6: Parameter-Settings 2050

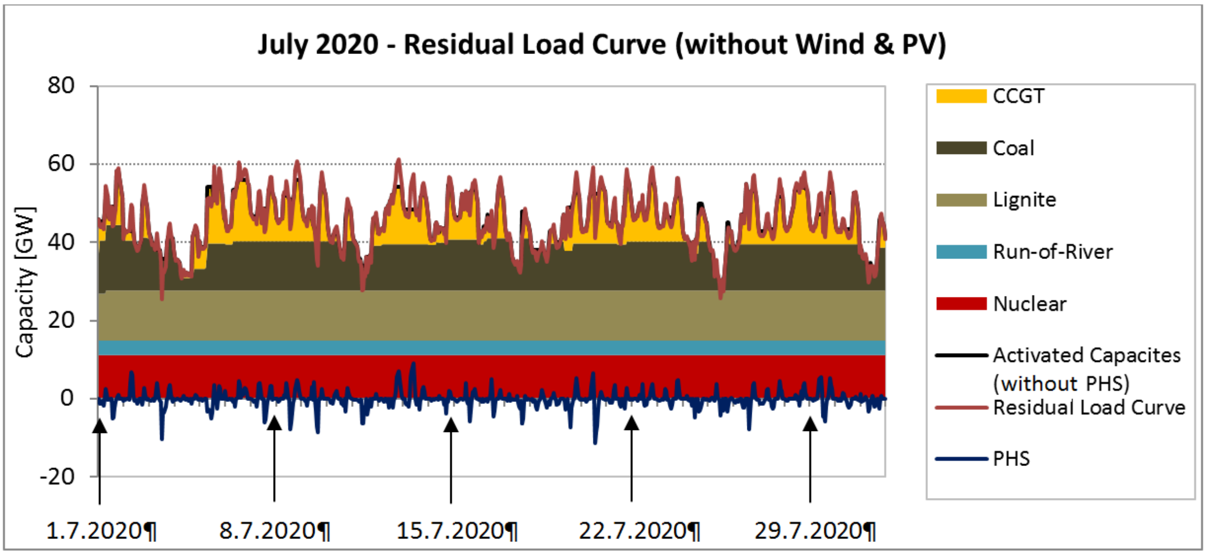

Figure 11: Residual Load Curve, July 2020, with Thermal Feed in and the Contribution of PHS

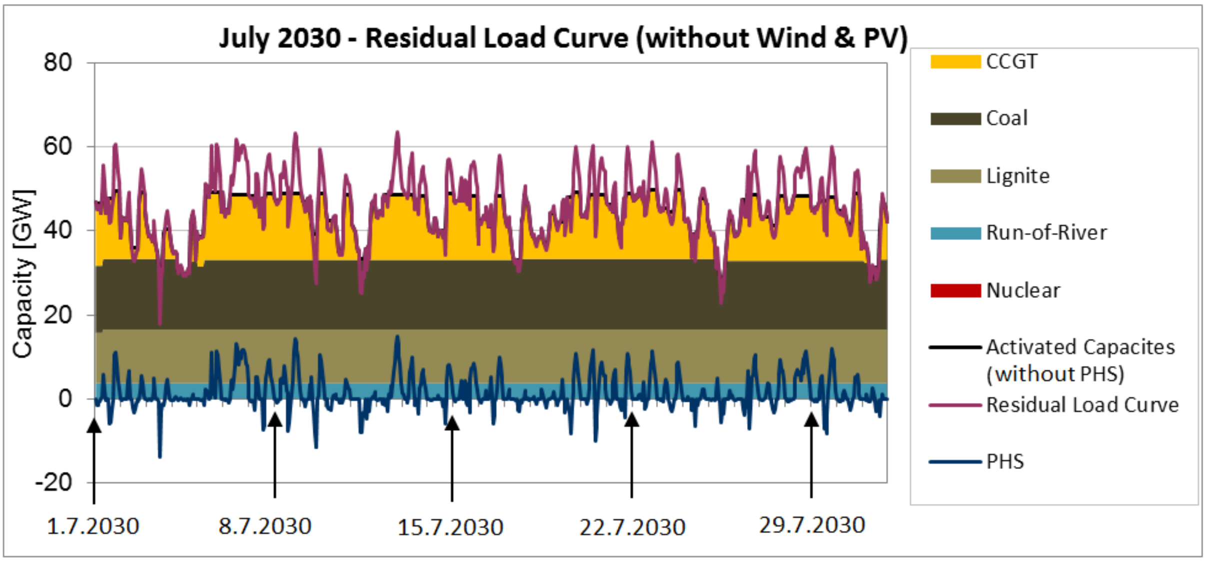

Figure 12: Residual Load Curve, July 2030, with Thermal Feed in and the Contribution of PHS

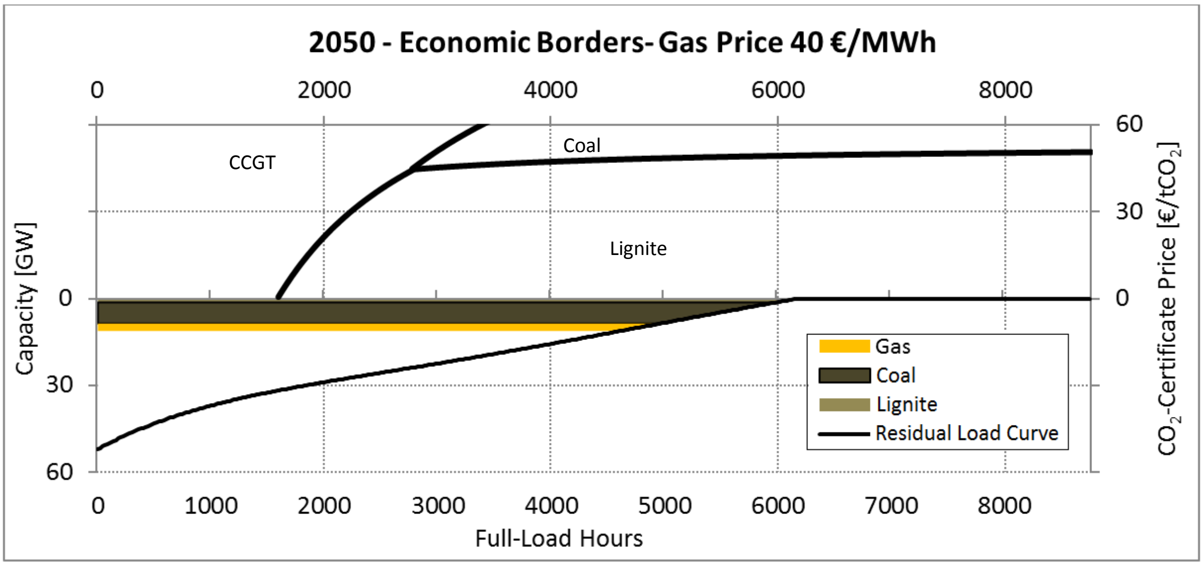

Figure 13: Economic Borders, Germany 2050, Gas Price 40€/MWh