Thermal Power Plant Economics and Variable Renewable Energies

A Model-based Case Study for Germany

Johannes Trüby
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Executive summary

Many operators of thermal power plants in Europe have recently been suffering from deteriorating economics of their power stations. Indeed, power prices have dropped markedly over the last couple of years and therefore affected the operation and income of power plants. This drop in prices is caused by various reasons: first, the economic slow-down following the fallout of the financial crisis has depressed power demand growth in Europe. Second, coal prices decreased against the expectations of many market participants and similarly, CO₂ prices remained lower than expected. Finally, political support for renewable energies has resulted in strong deployment of wind and Solar PV in many countries.

This paper is primarily concerned with the effect of increasing shares of variable renewables on the economics of typical thermal power plants in Germany. The analysis rigorously assesses how increasing shares of variable renewable energies affect power prices and how this feeds back on the operational characteristics of individual thermal power plants and their revenues. In doing so, two models are developed and fed with fundamental power market data. The first model – an optimisation model for the German power system – produces hourly price (forward) curves for Germany given the power plant fleet, the electricity load structure and the generation profile of variable renewable energies. The second model uses these power price (forward) curves as an input and determines the optimal generation schedule of individual power plants taking into account a detailed representation of technical constraints.

The findings confirm the negative impact on the income of thermal power stations and stress that some types of plant become unprofitable with increasing deployment of variable renewables. The degree to which plants are affected varies by technology and age of the station. Typically, plants that are older and have fully recovered their investment expenditure fare better. Current relative fuel prices for coal and gas imply that coal-fired plants are usually dispatched before gas-fired plants in the merit order giving them an economic advantage.

A power plant is retired or mothballed when its revenues are not sufficient to cover its variable cost and annual fixed cost. Usually plants are kept in the market even if they do not manage to recover their investment expenditure (since these costs are sunk). The findings suggest that most plants can still earn their variable and annual fixed costs and are hence not in danger of being retired prematurely. Consequently, there appears to be no immediate cause for alarm in terms of an imminent shortage of capacity due to thermal plant being crowded out by increasing shares of variable renewables. However, the fact that new plants cannot recover their investment expenditure implies that power generators have no incentive to invest in new reliable capacity under the current market circumstances. In the longer term, when old units reach the end of their technical lifetime new plants are needed to (at least partially) compensate for these retirements. Policy-makers are advised to carefully monitor the profitability of reliable power generation capacity and possibly introduce measures to counter the deterioration of economics in case power price signals are not high enough to induce investment for sufficient amounts of reliable capacity.
Introduction

Many OECD countries have introduced effective policies to increase the share of renewable energies (REN) in power generation with support measures aimed at fostering the deployment of technologies that are not yet competitive today. This has led to unprecedented growth rates in wind and solar power deployment in countries like Spain, Italy, the United Kingdom, Denmark or Germany. Many countries have set themselves ambitious targets to further increase power generation from REN in the coming decade (see e.g. the National Renewable Energy Action Plans). The dynamic evolution of REN deployment has started re-shaping power markets and will even more intensively do so in the coming years.

Despite the impressive growth of REN, OECD power generation is still dominated by fossil fuels and nuclear power. However, the generation characteristics of wind and solar, particularly the variability of output and the negligible variable costs of generation, have already impacted the economics of thermal power stations. Three key effects harm the profitability of thermal plants: firstly, the renewables get their remuneration through a support scheme that is independent of the price evolution on the wholesale power market. Their deployment rate does therefore not react to price signals from the wholesale market. Secondly, due to their low variable costs, variable renewables are dispatched before the other power plants and therefore have a depressing effect on power prices (merit-order effect). As the other power plants get their remuneration from the wholesale market, this effect reduces the revenues of any power station in the market. Secondly, the preferential access of variable REN requires more flexible operation of the conventional fleet, typically resulting in additional costs.

The question arises whether the operational incomes of thermal power stations will suffice to cover their annual fixed costs in the future. The discussion has so far mostly centred on the question whether there are adequate monetary incentives for investors to build new power stations in markets with increasing shares of REN. Indeed, thermal power plant fleets are ageing in many OECD countries and large parts of the installed capacity will reach the end of their technical lifetimes in the decade to come. Therefore the financing of replacements is crucial. However, the technical lifetime of a power plant is only a weakly binding restriction. Many components of a plant have a much longer lifetime than typically assumed and those components that reach the end of their lifetime can usually be exchanged to sustain the lifetime of a plant. More important is whether it is economically viable to keep a plant operational that was initially designed to generate power under completely different market conditions.

Clearly, premature decommissioning of old power stations could further increase the challenges of integrating REN whereas providing a sound economic basis for old thermal plants could buy more time and hence relieve the pressure to invest into new reliable generation capacity. Germany, the largest power market in Europe, is a good example for the transition from a fossil-based to a REN-based power system. Germany still generated 60% of its electricity from fossil fuels in 2011, most of which comes from lignite and hard coal. However, REN have already contributed 20% to the country’s power output in 2011. This share is targeted to increase to 35% by 2020 (Erneuerbare Energien Gesetz). The bulk of the additional REN is expected to come from, weather-dependent and therefore naturally variable, solar and wind power. At the same time the German power plant fleet is ageing: 75% of the hard-coal fired, 51% of the lignite-fired and 40% of the gas-fired generation capacity was built before 1985.

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1 The term operational income refers to revenues from power sales minus (variable) cost of power generation. Variable costs of power generation include fuel and CO2 costs, part-load operation costs and start-up costs.
The majority of these plants were designed for non-cyclical baseload operation with only few start-ups per year. As increasing in-feed from REN requires more flexible operation of thermal power plants and potentially depresses prices, it is unclear how the profitability of old stations will evolve under increasing shares of REN. In the scope of this paper, “old” stations are such plants that have fully recovered their investment costs, in contrast to “new” stations which were built recently and have not yet recovered their investment expenditure. While new power stations usually offer fast load changes, low minimum load, rapid start-ups and less costly cycling operation (costs associated with part-load efficiency loss), old stations would need retrofitting to improve their flexibility parameters. Moreover old power stations have lower fuel efficiencies.

This paper analyses the economics of existing thermal power stations under increasing shares of variable REN over the time period from 2011 to 2025. For the sake of brevity and tractability the analysis deals only with the German power market. The case study pursues a modular approach. First, the impact of increasing generation from REN on power prices is determined. In doing so, hourly power generation from REN is deducted from hourly load to derive an hourly residual load curve. Then a linear programming power-dispatch model for the German market is applied to compute hourly prices.

In a second step the hourly power price (forward) curves feed into a power plant operation model. Given these power prices, this model determines the optimal generation schedule of an individual power station subject to a number of technical and economic constraints such as start-up times and costs, ramping gradients, fuel costs and efficiency, minimum load level, part-load efficiency loss etc. This allows calculating the hourly operational income of an individual plant.

Using a set of input parameters for four different “benchmark” thermal power stations, the approach allows quantifying the effect of intermittent REN power generation on the economics of these plants. The analysis considers several aspects of variability of REN: first, the impact of different wind-years on power plant operational income is scrutinised. In this part of the analysis the installed wind capacity is kept constant while the hourly generation profile is varied.

Second, the effect of increasing wind and solar capacity on operational income of thermal plants is quantified. In doing so, the hourly wind and solar in-feed profiles are kept constant while the installed capacity is varied. Specifically, German wind and solar capacity expansion targets for the years 2015, 2020 and 2025 are considered. The targets suggest that PV capacity almost triples from 20 GW in 2011 to 57 GW in 2025 and wind capacity almost doubles from 30 GW in 2011 to 58 GW in 2025.

Third, a sensitivity analysis regarding power plant retrofitting is conducted. This allows quantifying the value of modernising a plant to make it more flexible and efficient in a market with increasing shares of REN. Finally, an alternative scenario is presented which accounts for the dynamics of power markets and quantifies the effect of changing power market fundamentals such as power plant fleet evolution as well as fuel and CO₂ price developments.

The main findings and conclusions of the analysis are:

- Given current REN capacity, varying wind-years have a minor effect on the operational income of thermal power plants. The effect increases with increasing shares of REN. However, generators should be able to hedge themselves against this uncertainty.

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2 Wind yield and therefore wind power output can vary markedly from year to year. Different wind power generation profiles over the years are referred to as different wind-years.

3 The capacity targets to 2020 follow the National Renewable Energy Action Plan (NREAP, 2010) for Germany and IEA (2012c). The targets for the period 2020 to 2025 were derived from Leitstudie (2011).
• Increasing shares of REN can have a substantial effect on the operational income of all types of existing power stations. REN capacities corresponding roughly to 2025 targets might change market conditions in a way that operational incomes of old stations might not suffice to cover fixed operation and maintenance costs (see also IEA 2013).

• Retrofitting can increase the flexibility and efficiency of individual old stations thus improving their operational income prospects markedly. Whether a station should be retrofitted depends on technical site-specific characteristics of the unit.

• Keeping other power market fundamentals constant shows that increasing shares of intermittent REN have a deteriorating effect on the profitability of the existing thermal fleet. Whether this will cause market-exit depends on the evolution other power market fundamentals such as power demand evolution, relative fuel prices and power generation capacity evolution (e.g. nuclear phase-out in Germany).

• Whether there is need for political action remains thus unclear. In any case the analysis confirms the fear that profitability of the thermal fleet might dwindle with increasing shares of REN. Yet, policy makers should stay alert and monitor the developments on power markets closely and be prepared to take action.
Approach Outline

The study is conducted using two different linear optimisation models (module 1 and 2) and a supplementary net present value model (module 3) for the retrofit analysis (see figure 1). The first stage of the approach applies a dispatch model for the German power market to determine hourly power prices. These power prices are used as input parameters for a more detailed power plant operation model. The power plant operation model delivers the optimal generation schedule and the operational income of an individual power plant. Depending on the target of the analysis the income streams can be used as inputs for the net present value (NPV) model. The following sections describe the properties, input and output parameters and variables of these models in detail.

Figure 1 • Modular Analysis Approach

A dispatch model for the German power market

The dispatch model for the German power market determines the least-cost generation schedule of the German conventional power plant fleet to meet residual load in every hour of a year. The hourly power prices thus correspond to the variable generation costs of the last unit needed to satisfy demand in this hour. The variable costs of a power station consist of the fuel costs (including the transportation cost to the plant), CO₂-emission costs and other variable cost components such as desulphurisation (in the case of fossil-fired plants) or storage of used fuel rods (in the case of nuclear power stations). The power station data stems from Bundesnetzagentur (2012a) and was enhanced with generic power plant efficiency data for vintage/technology/fuel-type classes of power stations. The power plant data from Bundesnetzagentur (2012a) was aggregated into 120 power plant classes and implemented in the model.

The price is determined by the intersection of a merit-order curve with a (price-inelastic) residual load curve (figure 2). Hence, the model implicitly assumes a perfect relationship between residual load and power prices. Although in reality there clearly exists a strong positive correlation between prices and residual load this relationship is not perfect (see figure 3). Therefore the model results are inevitably biased to some degree.
The left-hand side of figure 4 displays solar PV generation for a week in May 2011 with 2011-capacities and 2025-capacity targets. The right-hand side of figure 4 shows wind generation for a week in October 2011 with 2011-capacities and 2025-capacity targets. While solar power generation follows a similar pattern every day, the key uncertainty is the level of output which depends on the season, clouds, snow or dust on the panels etc. Wind power generation however varies with regard to the in-feed pattern and the output level.

The model was implemented in GAMS as a linear cost-minimisation problem and solved using CPLEX. The model has more than one million variables and solves in about 30 seconds on a standard desktop machine.
**Figure 4 • Solar PV (a week in May - left) and Wind (a week in October - right) generation for 2011-capacities and 2025-capacity targets**

Source: IEA analysis.

Hourly load data stems from ENTSO-E (2012) and the hourly REN data needed to derive the residual load curve comes from the four TSO’s in Germany (see Tennet (2012), 50 Hertz (2012), Amprion (2012) and Transnet BW (2012)) as well as BMU (2012).

The figure 5 shows the prices simulated with the model for the year 2011.

**Figure 5 • Hourly power prices simulated for 2011**

Source: IEA analysis.

**A thermal power plant operation model**

The hourly prices determined with the dispatch model are used as input data for a more detailed individual power plant model. Taking hourly power prices as given, this model determines the optimal power generation schedule of an individual power station in order to maximise its operational income. The model is calibrated taking into account technical and economic data of different power stations to assess their respective profitability in a market with increasing shares of variable REN. Table 1 gives an overview over some key parameters used in the analysis. Due to the binary nature of some of the restrictions, the model was implemented as a mixed-integer linear programme in GAMS and solved with CPLEX. The implementation closely follows the formulation proposed by Arroyo and Conejo (2004) with only a few amendments. The model has an hourly resolution and is solved for 8760 hours (one year).
While determining the optimal power generation schedule the generator considers a set of technical and economic restrictions. Specifically the following restrictions are explicitly considered:

- Start-up costs, start-up duration and power output trajectory during start-up
- Shut-down power output trajectory and minimum downtime
- Efficiency loss when operating in part-load and minimum load level
- Ramping gradients

Starting-up a power plant is typically costly due to the extra fuel use for pre-heating the steam cycle and additional wear-and-tear associated with start-up processes. Once the station reaches full-load it can generate electricity at maximum efficiency. The production costs consist of fuel and CO2-emission costs. The station can react to temporal price drops by cycling operation i.e. ramping up and down between minimum and full-load at a speed determined by the station’s ramping-gradient. Yet, operation below full-load usually comes at a cost due to a part-load efficiency loss.

**Table 1 • Key technical and economic parameters of benchmark power station**

<table>
<thead>
<tr>
<th></th>
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<th></th>
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<tr>
<td>Plant capacity in [MW]</td>
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<td>800</td>
<td>350</td>
<td>400</td>
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<tr>
<td>Minimum load in [MW]</td>
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<td>200</td>
<td>210</td>
<td>160</td>
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<tr>
<td>Maximum efficiency in [%]</td>
<td>38%</td>
<td>46%</td>
<td>48%</td>
<td>59%</td>
</tr>
<tr>
<td>Part-load efficiency in [%]</td>
<td>31%</td>
<td>40%</td>
<td>37%</td>
<td>48%</td>
</tr>
<tr>
<td>Emission factor in [t CO2/MWh(th)]</td>
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<td>0.339</td>
<td>0.202</td>
<td>0.202</td>
</tr>
<tr>
<td>Start-up cost in [EUR/start-up]</td>
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<td>40 000</td>
<td>9 000</td>
<td>7 000</td>
</tr>
<tr>
<td>Fixed operation and</td>
<td>28</td>
<td>28</td>
<td>23</td>
<td>23</td>
</tr>
<tr>
<td>maintenance costs in [EUR/kWa]</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ramping gradient [% of installed capacity/min]</td>
<td>1.5%</td>
<td>3.0%</td>
<td>2.0%</td>
<td>4.0%</td>
</tr>
<tr>
<td>Duration of start-up process in [h]</td>
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<td>3</td>
<td>2</td>
<td>2</td>
</tr>
<tr>
<td>Minimum down time [h]</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>2</td>
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</table>

Source: IEA analysis.

Cycling operation is determined by the following trade-off: during minimum load operation the plant usually incurs an operational loss as the revenues in these hours (of low prices) do not suffice to cover all variable costs. However, minimum load operation has the advantage that the station remains connected to the grid and can thus ramp up rapidly when prices increase, resulting in additional revenue opportunities. Part-load operation thus avoids start-up costs, down-times and potentially long start-up processes. In other words, minimum load operation is an option for later revenues which comes at the cost of current losses. When the expected revenues at later times exceed the losses, the station remains online otherwise it shuts down.

Figure 6 displays the generation schedule of an old 400 MW coal-fired unit and its corresponding operational income. The unit starts up in the morning of Friday January 7 (January 6 is a public holiday in some parts of Germany) and shuts-down after 11 hours of full-load operation. The unit remains shut-down over the weekend when low power prices do not justify its operation. It starts-up again on Monday 10 January and incurs the start-up costs of about 30 k EUR. The unit remains online until Friday 15 January when it shuts down in the night.
The unit profitably generates power at full-load (400 MW) during the day when prices are sufficiently high. It reduces its output to minimum load (200 MW) at off-peak times when prices are low. In these hours the unit typically incurs an operational loss.

The assumed unit runs for a total of 5 358 full-load hours in 2011 (load factor 61%). It starts up 44 times during the year and yields an annual operational income of EUR 15.4 million. Deducting annual fixed operation and maintenance costs (FOM) of EUR 28/kWa would leave the unit with a total income of EUR 4.2 million for this year. Figure 7 displays the distribution of hourly operational income of the unit in 2011. The unit is operational, in full-load and part-load, for a total of 6 093 hours in 2011. The one hundred most profitable hours (3% of operational time) contribute 20% to the total operational income of the unit in this year.

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4 FOM costs include all costs fixed maintenance cost (e.g. repairs) and operation cost (e.g. labour cost). The FOM costs do not include investment costs or debt service.
Variable renewables and power market fundamentals

Increasing shares of REN impact residual load – which is served by the conventional power station fleet – and therefore change power prices, operational patterns and operational income of thermal power plants. With increasing shares of variable REN, residual load is lower and more volatile (figure 8).

The bandwidth of residual load fluctuation increases substantially with higher shares of REN. While residual load oscillates between around 20 GW and 70 GW with 2011-REN capacities this range widens to -10 GW to 70 GW with 2025-REN capacity targets. Negative residual load occurs in 35 hours with 2025-REN capacity targets, implying the need for storage or curtailment.

Figure 8 • Hourly residual load in GW with 2011-REN capacity (left) and 2025-REN capacity (right)

Hourly residual load swings also become more pronounced (Figure 9). For instance, while with 2011-REN capacities load changes of more than 4 GW within one hour only occurs in 12% of the time per year, this share almost doubles with 2025-REN capacity targets. The more pronounced load swings, both up and down, emphasise the need for fast ramping capabilities in the power plant fleet when REN capacity is being expanded.

Figure 10 presents exemplary price-results of the power plant dispatch model for Germany. The hourly prices have been sorted from highest to lowest to produce the price duration curves displayed in figure 10. Clearly, increasing shares of REN depress prices in most hours of the year. Yet, Germany is a winter-evening peak-load system, therefore load peaks are hardly affected by increasing shares of REN and hence price spikes in winter evening hours are there to stay.

While some wind mills will certainly produce power on winter evenings, the reliable share of wind power amounts only to around 6%, according to a study of the Leibniz Institute for Economic Research (2012). In other words, only around 60 MW of dispatchable plants can be replaced by one additional Gigawatt of wind capacity.

As a result, the highest price hours (which correspond to the highest load hours in the model) are hardly affected while the prices of many other hours are depressed, resulting in a price duration curve that becomes “steeper”.

The impact of varying wind profiles on power plant income

Due to varying meteorological conditions the yield of wind power plants can also vary over the years. While this effect is particularly important for wind farm-investments it potentially also has an effect on the utilisation and hence the income of thermal units. Figure 11 presents utilisation rates of wind power plants in Germany for recent years. In the period 2006 to 2011 average utilisation rates of wind power plants fell in a range between 21.2% (2007) and 15.4% (2010). The year 2007 was a very good wind-year, 2010 was an extraordinarily bad wind-year and 2011 was a typical wind-year.
Although six-year data is not representative from a meteorological point of view, long-run wind yield data also suggest that 2011 was a normal wind-year in terms of total wind yield (see e.g. BDEW, 2012). However, total wind-yield per year is not the only relevant aspect for the operation of thermal power stations. The wind in-feed pattern or more specifically the stochasticity of wind generation is a similarly important aspect. In other words: a high-yield wind-year with extraordinarily strong wind generation during nights and weekends may have minor impacts on the profitability of the conventional fleet. Similarly, long periods of constantly high wind generation might be easier to handle for the conventional fleet than the same amount of wind irregularly spread over a longer period of time.

**Figure 11** Annual variability of load factors of wind mills in Germany

The analysis of annual variability of wind yield on thermal power plant economics is based on wind generation profiles of the years 2006 to 2011. To quantify the impact of annual variability of load factors of wind mills on thermal power plant profitability, only the wind generation-profiles are being varied in the analysis i.e. all other fundamental market data such as fuel and CO₂ prices, load and load structure, solar PV structure, power plant fleet etc. remains the same. For the analysis of annual variability of wind yield with 2011-REN capacities, all market parameters except the wind generation profiles are as of 2011. For the analysis of the 2025-capacity targets the same parameters are used but the wind and solar PV generation capacities are adjusted to the 2025 targets.

Varying wind yield has little effect on power prices given 2011-REN capacities (figure 12). However, with 2025-REN capacity targets varying wind yield has more leverage on power prices. This effect is more pronounced for low prices. Broadly speaking, price spikes occur in hours with high load and low REN generation. Therefore any expansion of intermittent REN capacities will further depress prices in hours in which prices are already depressed by REN-generation but have a minor effect on high-price hours.

Figure 13 presents the operational income (for reasons of comparability normalised to k EUR/MW of installed capacity) for four benchmark power stations (see table 1). In general, the evolution of operational incomes follows an inverted trend compared to the wind yield evolution (figure 11).
At wind power capacity as of 2011, the annual variability of wind yield has a minor impact on the economics of thermal plants. For example, the maximum deviation of operational income from the six-year average amounts to 12% (2010-wind year) for an old CCGT and 8% (2010-wind year) for a new CCGT. Similarly, the maximum deviation from the six-year average stands at 14% (2010-wind year) for an old coal plant and 8% (2010-wind year) for a state-of-the-art coal fired station.

The situation changes when 2025-REN capacity targets are assumed. In this case, the fluctuation of operational incomes increases markedly. The maximum deviation from the six-year average operational income stands at 17% (2010-wind year) for the old CCGT and at 14% for the new CCGT. The maximum deviation from the mean income amounts to 24% for the old coal-fired unit and 17% for the new coal plant.

Clearly, the older plants are closer to the margin and therefore more exposed to the annual variability of wind-yield. The newer plants are intra-marginal in more hours and therefore less exposed to the fluctuations in prices. The key findings of this analysis are:

- While for investors into wind power varying annual wind yield has a direct effect on profitability, the profitability of thermal units is only indirectly affected and also depends on the stochasticity of wind generation.
- With the expansion of REN capacities, the effect of varying wind yield becomes more pronounced. This affects mainly those hours in which REN already have a price depressing effect.
• Especially new plants that are not yet amortised need stable incomes for debt service. These plants are potentially jeopardised by varying wind yield. However, due to their operational characteristics they are more often intramarginal and, at least in terms of utilisation, they have therefore a lower exposure to these fluctuations.

• Over longer time periods variations in operational income will balance and hence approximate the mean income. Generators typically have instruments to hedge themselves against such uncertainties.

Increasing shares of renewables and power plant economics

The analysis of different REN-capacity expansion targets on thermal power plant economics is based on fundamental market data for the year 2011. This is the case for fuel and CO₂ prices and their evolution during the year. Similarly load and the load structure are as of 2011. While the generation profiles of wind and solar generators are also as of 2011 their installed capacity is being varied according to national REN expansion targets (see table 2). 2011 is a good base-year for the REN generation profiles since wind yield and solar radiation (see BDEW, 2012) were reasonably typical in this year.

Table 2 • Key market parameters and REN targets

<table>
<thead>
<tr>
<th></th>
<th>2011</th>
<th>2015</th>
<th>2020</th>
<th>2025</th>
</tr>
</thead>
<tbody>
<tr>
<td>Solar PV [GW]</td>
<td>20.3</td>
<td>38.7</td>
<td>51.8</td>
<td>57.3</td>
</tr>
<tr>
<td>Wind onshore [GW]</td>
<td>29.2</td>
<td>33.6</td>
<td>35.8</td>
<td>41.4</td>
</tr>
<tr>
<td>Wind offshore [GW]</td>
<td>0.4</td>
<td>3.0</td>
<td>10.0</td>
<td>16.8</td>
</tr>
<tr>
<td>Load [TWh]</td>
<td>484</td>
<td>484</td>
<td>484</td>
<td>484</td>
</tr>
<tr>
<td>Coal price [EUR2011/MWhth]</td>
<td>14.3</td>
<td>13.6</td>
<td>12.2</td>
<td>12.3</td>
</tr>
<tr>
<td>Gas price [EUR2011/MWh]</td>
<td>23.4</td>
<td>25.2</td>
<td>29.8</td>
<td>30.9</td>
</tr>
<tr>
<td>CO₂ price [EUR2011/t CO₂]</td>
<td>13.2</td>
<td>11.5</td>
<td>21.6</td>
<td>25.2</td>
</tr>
</tbody>
</table>


Perhaps most importantly, power generation capacities in the German system are assumed to remain constant at 2011-levels. In the context of the complete nuclear phase-out until 2022 and the commitment to further increase REN-shares one would expect some adjustments in the power plant fleet over time (see e.g. Fürsch et al., 2012). Hence, the analysis should not be misunderstood as a forecast but rather as a sensitivity regarding the effect of different REN-targets on individual power plants’ economics. This approach has the advantage that the results can easily be interpreted and the drivers are clear.

With wind and solar PV capacities being the only augmented parameters in the analysis, the direction of the effect is unambiguous – power prices will be depressed on average (see figure 10). Consequently, profitability of thermal plants will decrease. However the magnitude of the effect is unclear. Figure 14 reports the operational income and a proxy for FOM costs for the four benchmark power stations. The difference between the operational income and the FOM determines whether the station earns a positive or a negative income. However, one has to keep in mind that FOM does not include investment costs. The new power stations (built during the past few years) are not yet amortised and hence need to earn an additional charge to cover their investment expenditure. The old CCGT and coal-fired stations, built in the late 1970s and early 1980s respectively, have fully recovered their investment costs.
The new CCGT and coal-fired power stations make healthy incomes with low shares of REN and remain profitable for any of the analysed REN-targets. Yet, also for flexible state-of-the-art power stations, incomes shrink with increasing shares of REN. The figure 15 compares the annual operational income of a new CCGT to its FOM and annual cost of capital. Under the study’s assumptions, the new CCGT does not fully recover its investment costs with the 2015-target REN capacities and the situation further deteriorates with increasing shares of REN. Even in this case, the station would not exit the market as long as it makes a positive income. Although the new-built plants are not driven out of the market by any of the analysed REN-targets, the effect on their income might still affect future investment decisions and therefore jeopardise system stability.
Table 3 • Number of power plant start-ups per year

<table>
<thead>
<tr>
<th>Power Plant Type</th>
<th>2011</th>
<th>2015-target</th>
<th>2020-target</th>
<th>2025-target</th>
</tr>
</thead>
<tbody>
<tr>
<td>CCGT old</td>
<td>113</td>
<td>99</td>
<td>105</td>
<td>92</td>
</tr>
<tr>
<td>Coal plant old</td>
<td>44</td>
<td>46</td>
<td>44</td>
<td>32</td>
</tr>
<tr>
<td>Coal plant new</td>
<td>20</td>
<td>39</td>
<td>49</td>
<td>54</td>
</tr>
<tr>
<td>CCGT new</td>
<td>73</td>
<td>98</td>
<td>132</td>
<td>140</td>
</tr>
</tbody>
</table>

Source: IEA analysis.

The situation is different for old stations. While profitable under 2011-capacities, they become marginally unprofitable under 2015-REN targets and clearly loss-making under 2020 and 2025-REN targets. Their design and technical characteristics hamper profitable operation in a market with increasing shares of REN. Hence, in markets with REN capacity expansion as the dominant fundamental driver such plants might be forced to exit.

As figure 16 shows, full load hours of all plants decrease with increasing shares of REN. The state-of-the-art plants (coal and gas) slip from baseload operation to mid-merit operation, realising around 5 000 full load hours per year under 2025-REN capacity targets. Contrarily, the new CCGT’s part load operation time increases by 10% from 933 hours with 2011-REN capacities to 1 025 hours with 2025-REN targets. The increase in part-load operation time is even more pronounced for the new coal-fired station. Part-load operation time increases by 17% from 1 257 hours with 2011-REN capacities to 1 473 hours with 2025-targets. Hence, for new stations a plunge in full-load hours is paralleled by an increase in part-load operation time. Moreover, the number of power plant start-ups also increases for new stations with increasing REN-capacity expansion (table 3). This highlights the increasing need for flexibility in a system with increasing shares of REN.

The old plants’ full load hours drop from around 5 000 under 2011-REN capacities to around 2 000 as REN capacities are expanded to meet 2025 targets. Part-load operation time decreases for the two old plants however the drop in part load operation time is more substantial for the coal-fired station. For old stations, the number of start-ups per year drops slightly with increasing shares of REN. The operational data confirms the difficulty old stations have persisting in a market with increasing shares of REN.

Figure 16 • Annual full load hours (left) and part-load operation time (right) for benchmark power plants under increasing shares of REN

Source: IEA analysis.

The number of start-ups is lower for the coal-fired stations than for the gas-fired plants. The coal-fired power stations start-up 20 to 54 times per year depending on the REN-capacity target. The shut-downs typically occur during weekends with low load and/or high REN generation.
The number of start-ups of the two CCGTs falls in a range of 73 to 140 start-ups per year. In addition to the weekends these stations sometimes also shut down during the night or during periods of very high REN output. The key findings of this analysis are:

- Increasing shares of REN alone do not drive the state-of-the-art benchmark power stations out of the market. Whether the income they make suffices to cover their investment costs is a different issue and needs further analysis.
- The need for a more flexible operation of power stations is highlighted by the fact that the number of start-ups increases substantially for modern stations. Furthermore, part-load operation time increases for modern stations while full-load hours decrease – another indicator for increasing flexibility requirements.
- The profitability of old benchmark units is severely affected by increasing shares of REN. Expansion targets to be reached within a decade could render these plants loss-making.
- A generalisation is nevertheless difficult as only a few stations will actually have comparable parameters to the benchmark stations and many plants have additional income such as revenues from the balancing market or ancillary services.
- Moreover, many stations were designed as CHP plants often hampering flexibility but providing a steady revenue stream from heat sales.

The role of retrofitting in rapidly changing power systems

Often it is possible to retrofit old power stations, either to extend their lifetimes or to improve their operational performance. Retrofitting comprises a wide array of possible measures ranging from a rapid and not very costly exchange of valves in the boiler system to a complete replacement of the steam-turbine system.

Power stations are usually not standardised but were individually designed for specific requirements and specific locations. Such requirements could be serving a local demand for heat and therefore generating power in CHP mode or having adjusted the boiler system to a specific (regional) coal quality. Different individual components may need to be replaced after decades of operation. The retrofit measure implemented might therefore depend on the individual component to be exchanged. Hence, there is no standard set of retrofit measures but only site-specific measures that lead to different results and are associated with different costs. The following examples cannot be generalised but give an overview of how diverse retrofitting measures can be.

Exchange of coal mills and coal transport system in a coal-fired unit

An example for a retrofit measure that allowed for improved ramping and lower minimum load was the modernisation of the coal mills and coal transport system in a hard coal-fired power station in Germany. In this plant the minimum load and ramping was constrained by the output of the coal mills and the conveyor belt system that served the boiler of the plant. Mills and conveyor belts could only run at specific speeds that did not allow going below a certain output level. Exchanging the coal mills and improving the control system increased the flexibility of the plant substantially. Moreover, the new coal mill produces pulverised coal with a smaller particle size which leads to improved combustion behaviour and consequently a better fuel efficiency of the plant.
Exchange of the gas turbines in CCGT power plant

Two CCGT units, each with a capacity of 400 MW, were commissioned in 1975 with one 50 MW open-cycle gas turbine per unit. The units realised an efficiency of 41% when running in combined-cycle mode. The old inefficient open-cycle gas turbines were replaced by state-of-the-art aircraft gas turbines. These turbines realise efficiencies of almost 44% in open-cycle operation. Each of the old gas turbines was substituted by two new turbines with a capacity of 58 MW each. After retrofitting each unit reached an efficiency of almost 47% when running in combined-cycle operation. Furthermore, the unit’s capacity increased to 475 MW and operational flexibility was improved. The unit can either use only one or both turbines and can thus easily ramp up and down in a load range of 40 MW to 475 MW. During the installation process of the turbines the power plant was also equipped with two diesel generators to make the turbines suitable for provision of black start power. The cost of the upgrade was around EUR 200 million for both units (EUR 250/kW).

Modernisation of Instrumentation and Control Technology in a coal-fired unit

The retrofitted coal-fired unit has a capacity of 600 MW and was commissioned in 1984. The Instrumentation and Control Technology (ICT) was recently modernised to improve the flexibility of the unit. This has led to several improvements such as faster ramping from an initial 8 MW/min to 12 MW/min and a reduction of minimum output from 200 MW to 150 MW. Moreover, the measure has also reduced heat consumption by about 10% for cold and warm starts and hence lowered start-up costs markedly. The new ICT also allows for a better monitoring and protection of the boiler components and is thus expected to also improve the availability of the unit. The cost of the ICT retrofit stands at EUR 3 million (EUR 5/kW).

High-temperature heat storage vessels for CHP units

Heat storage vessels allow CHP units to produce more heat and less electricity in times of low power prices. The heat is stored and used later e.g. to serve heat demand and produce more power in times with high electricity prices. The heat storage vessels avoid costly start-up processes and reduce potential losses during minimum-load operation. Depending on the unit’s capacity heat storage vessels can have different sizes.

Figure 17+ Annual operational income and fixed operation and maintenance cost (FOM) with and without retrofitting

![Figure 17](image)

Source: IEA analysis.
Retrofitting can increase a unit’s performance in a market with increasing shares of REN substantially. The following analysis is based on the same assumptions as before (see table 1). However, the old coal plant is assumed to be retrofitted. The retrofitted plant reaches an efficiency of 40.5% as compared to 38% for the old, un-modernised coal-fired station. Similarly, the part-load efficiency is 2.5%-points higher in the case of the retrofitted plant. Furthermore, retrofitting measures are assumed to reduce the minimum output of the plant from 50% to 20% of maximum capacity.

Figure 17 presents the annual operational income and FOM costs for a coal-fired power station with and without retrofitting. While the income of the non-retrofitted plant drops below its FOM costs already with 2015-REN capacity targets, the retrofitted plant can still earn its FOM with 2020-REN targets. Assuming a WACC (weighted average cost of capital) rate of 5.4% and a 10-year economic lifetime, the value of the retrofit measure (discounted cash flows) amounts to EUR 51.5 million (EUR 128/kW) if do not vary any parameter aside from the REN capacity. Hence, for this specific type of power plant any set of retrofit measures that leads to the above mentioned operational improvements, could have overnight cost up to EUR 128/kW. This corresponds to roughly 10% of the specific investment cost of a new coal-fired power station. Although the costs of retrofitting are site specific and dependent on the technical characteristics of the plant and the exchanged components, EUR 128/kW should allow for some quite substantial modernisation measures.

Figure 18 • Operation time of an old coal-fired unit with and without retrofitting (2025-REN target)

The operation time differs between a retrofitted and a non-retrofitted coal-fired plant under 2025-REN capacity targets (figure 18). The retrofitted plant benefits from a lower minimum output level and a higher efficiency (in full-load and part-load operation). This allows the retrofitted station to reduce output to minimum load at a lower cost and subsequently ramp-up rapidly to benefit even from short price spikes.

The main findings of this analysis are:

- Power plant retrofits cannot be generalised. The measures are typically site and plant specific. As a result, the operational improvements and the associated costs can vary strongly between the measures.
• Retrofitting can improve the economic performance of old stations substantially in markets with increasing shares of REN. Retrofitting could hence protect individual plants from premature decommissioning in markets with ambitious REN expansion targets.

Alternative scenario: dynamics of the power market

The analyses in the preceding sections focused on the effect of intermittent REN generation. In doing so, all market parameters, except those relevant to solar and wind power generation were kept equal. Yet, power markets are dynamic and therefore the evolution of other market fundamentals can amplify or mitigate the effect of REN capacity expansion on power plant economics. This section explicitly accounts for alternative fuel and CO₂ price evolutions, the nuclear phase-out, as well as commissioning and decommissioning of thermal power stations.

Power plant idling and new-built until 2015 follows Bundesnetzagentur (2012b). Over the period 2015 to 2025 a net-decommissioning of about 500 MW is assumed in the conventional power generation sector. In the period 2015 to 2020 three nuclear power stations go offline (Grafenrheinfeld, Gundremmingen B and Philippsburg II). The remaining six nuclear power stations (Grohnde, Gundremmingen C, Brokdorf, Emsland, Neckarwestheim II and Isar II) are shut-down before 2025. The nuclear power stations are assumed to be substituted by gas-fired power plants (see also Fürsch et al., 2012).

The fuel price evolution follows IEA (2012a) and IEA (2012b) for the medium-term (see table 4). After 2017 fuel prices segue into the fuel price assumptions of the IEA’s (2012d) New Policies Scenario (NPS). Similarly, the EU-ETS allowance price is assumed to follow the current forward prices and then follow the price trends assumed in the IEA’s (2012d) NPS scenario. Electricity consumption is assumed to remain at 2011 levels over the outlook period, as savings from energy efficiency measures are compensated by increasing demand.

Table 4 • Key market parameters and REN targets in the alternative scenario

<table>
<thead>
<tr>
<th></th>
<th>2011</th>
<th>2015</th>
<th>2020</th>
<th>2025</th>
</tr>
</thead>
<tbody>
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<td>33.6</td>
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<td>41.4</td>
</tr>
<tr>
<td>Wind offshore [GW]</td>
<td>0.4</td>
<td>3.0</td>
<td>10.0</td>
<td>16.8</td>
</tr>
<tr>
<td>Load [TWh]</td>
<td>484</td>
<td>484</td>
<td>484</td>
<td>484</td>
</tr>
<tr>
<td>Coal price [EUR2011/MWh]</td>
<td>14.3</td>
<td>13.6</td>
<td>12.2</td>
<td>12.3</td>
</tr>
<tr>
<td>Gas price [EUR2011/MWh]</td>
<td>23.4</td>
<td>25.2</td>
<td>29.8</td>
<td>30.9</td>
</tr>
<tr>
<td>CO₂ price [EUR2011/CO₂]</td>
<td>13.2</td>
<td>11.5</td>
<td>21.6</td>
<td>25.2</td>
</tr>
</tbody>
</table>


In general, the assumed fuel evolutions favour coal-fired power plants. Firstly, coal prices are assumed to decrease in the medium-term and stagnate after 2020. Contrarily, gas prices are assumed to increase markedly over the time horizon. A comparably low CO₂ price in the medium-term improves the competitive advantage of coal in the time period before 2020.

Figure 19 presents the annual operational income of the four benchmark power stations and the corresponding full-load hours in the alternative scenario. Clearly, both the old and new coal-fired power plants see their economics strengthened despite growing shares of REN.
In this case, the effects of advantageous power market fundamentals, i.e. fuel price evolutions and conventional capacity development, over-compensate the disadvantageous effects of increasing shares of REN.

The situation is, however, different for the two gas-fired plants. While the old CCGT is outright unprofitable in the alternative scenario, the new CCGT remains marginally profitable over the medium-term and gains momentum after 2020 with strongly increasing CO₂ prices. Again, whether the income suffices to cover the investment expenditure is unclear and not in the focus of the analysis. Interestingly, the new CCGT remains profitable even with less than 2 000 full-load hours per year. The high efficiency and flexible operational characteristics allow the station to benefit from price spikes even if they occur only for a few hours.

Due to the expansion of REN capacities, the old coal-fired power plant needs to be run in a more flexible manner as well. The old coal plants’ load factor drops by 24% between 2011 and 2025 but part-load operation time and the number of start-ups remain constant. The new coal-fired fired power station benefits from the phase-out of nuclear baseload capacity over the outlook period. As a result this station runs in baseload operation and hardly uses its flexible characteristics.

**Figure 19** Annual operational income, fixed operation and maintenance (FOM) costs, and full-load hours of benchmark power plants in the alternative scenario

Source: IEA analysis.

The operational income decreases for all plants between 2011 and 2015 and increase again thereafter. The reasons for this are: net capacity additions up to 2015 are positive with several coal-fired power plants, currently under-construction, coming online in this period. All remaining nuclear power stations are shut-down after (or at the end of) 2015. Secondly, there is a drop in coal and CO₂ prices in the medium-term. In combination with the increase in gas prices this change in fuel prices induces a gas-to-coal switch making it, even for modern gas-fired stations, difficult to compete against reasonably modern coal-fired stations.

The increase in CO₂ prices hardly affects the two modern plants irrespective of the used fuel. Typically older and less efficient power plants set the price in the power market while the modern stations are mostly intramarginal. Consider a simplified power market with two coal-fired power stations: an old plant with an efficiency of 34% and a new plant with an efficiency of 46%. The old coal-fired station is assumed to be always marginal and thus sets the price. A EUR 10/tCO₂ price-increase for EU-ETS allowances increases the marginal cost of the old station and hence the power price by about EUR 10/MWh (assuming price-inelastic demand). The marginal cost of the new plant increases only by EUR 7.4/MWh due to the higher efficiency. This increases the margin of the new power plant by EUR 2.6 for every MWh generated.
Clearly, in reality, it would not necessarily be a coal-fired power station that sets the price. A price increase for EU-ETS allowances might trigger a fuel switch from coal to gas. In this case, if the price-setting plant is an inefficient gas plant, it would raise the power price markedly and a modern gas-fired power station would benefit from this increase in CO₂ prices. How the income of intramarginal power station evolves with changing CO₂ prices depends on what happens at the margin. As marginal power stations are less efficient, an increase in power prices could compensate for the marginal cost-increase of intramarginal stations. The key findings of this section are:

- Although increasing shares of variable renewables have a negative impact on thermal power plant economics, the profitability of these plants will be determined by the evolution of various fundamental market parameters.
- Clearly, the economics of a thermal power plant can be strengthened by a drop in its own fuel price relative to the competing fuels’ prices. In this analysis, coal-fired power plants benefitted from a drop in coal prices paralleled by an increase in gas prices, but a reverse change in relative fuel prices would have a similar effect on gas-fired plants.
- The effect of rising CO₂ prices on thermal power plant profitability depends on a) how much the change in CO₂ price increases the marginal cost of the price-setting plants and b) how much the CO₂ price-change increases the marginal cost of the power plant in question. Theoretically, a modern hard-coal fired plant can gain from a CO₂ price increase.
- Capacity commissioning and decommissioning changes the merit-order and hence the price-setting. Two aspects are particularly important: first whether the power plant fleet increases or decreases relative to load evolution and second which relative position an individual power plant holds in a re-shaped merit-order.
Conclusions

This study analysed the economics of existing thermal power stations under increasing shares of variable renewable energies (REN) in Germany, according to national expansion targets up to 2025. The analysis focused on power stations representative of the German fleet and examined the profitability of these thermal plants under evolving market conditions due to the increase of REN.

The approach consisted of two main steps. Over a first phase, power prices were simulated accounting for the impact of increasing shares of VRE. These hourly power prices were then used as input data for a second model which determines the optimal generation schedule of an individual power station with a detailed modelling of its technical constraints.

It was shown that high shares of REN tend to induce a depression of power prices and thus of thermal units’ operational incomes. Old power stations are severely affected by the changing market conditions and from 2015-REN capacity targets on, they become unprofitable under the study’s assumptions. New flexible power stations adapt better to high shares of REN and their operational income remain higher than their fixed operational and maintenance costs. Consequently, they are unlikely to be driven out of the market. However, the fact that they cannot fully recover their investments costs when REN capacities increase might affect future investment decisions. This negative impact of increasing shares of REN on the thermal units’ profitability may be counterbalanced by the evolution of other market parameters.

It does not seem necessary to ring the alarm bell yet, but in the longer term there may be some need for policy action. For example, according to the World Energy Investment Outlook (IEA, 2014), there are different measures which could act as an incentive for investment in a sufficient amount of reliable capacity. Capacity mechanisms could be designed to give a signal about the need for firm capacity and provide the payments necessary to retain the adequate level of capacity in the power system. Another measure could consist in allowing adequate power pricing in scarcity conditions. However, although it could provide sufficient revenues to power stations, they would be subject to uncertainty and might not be attractive enough to investors. At the same time, it would be necessary to try and reduce the need for capacity through technologies which improve the efficiency of the power system, such as demand response mechanisms for example or through an increase of assistance between regions thanks to an expansion of network connections.
Annex – Thermal power plant operation model code

The following code is a simplified version of the thermal power plant model, reduced to one day. It may be directly copied and pasted in GAMS. The data is given here for a new CCGT. Power prices as well as gas and CO2 prices correspond to the 26th of April of 2011.

Sets
k hours /1*24/
i interval of ramping up and down in [h] /1*8/
alias (k, kk, kkk);

Parameters
eta_max Efficiency at full load in [%]
eta_min Efficiency at partload load in [%]
emission_factor factor of CO2 emissions in [tonnes per MWh(th)]
FC(k) fuel cost in [Euros per MWh(th)]
A fixed cost [Euros per MWh]
B start up cost [Euros per start up]
C shut down cost [Euros per shut down]
DD Duration of shut down in [h]
P_max maximum capacity in [MW]
p_min minimum load in [MW]
pd(i) power output corresponding to the i-th interval of shut down process in [MW] /1 20, 2 160/
pu(i) power output corresponding to the i-th interval of start up process in [MW] /1 80, 2 160/
pu_high power output corresponding to the highest interval of start up process in [MW]
pd_low power output corresponding to the lowest interval of shut down process in [MW]
RD Ramp down limit in [MW per h]
RU Ramp up limit in [MW per h]
UD Duration of start up process in [h]
lambda(k) price of electricity in [Euros per MWh]
FOM fixed operation and maintenance costs in [Euros per kWa]
o_var other variable costs (e.g. desulfurisation) [Euros per MWh(el)]
gas_price gas price [Euros per MWh(th)] / 20.26/
co2_price CO2 price [Euros per ton] /16.82/;

p_max = 400;
p_min =160;
eta_max = 0.59;
eta_min = 0.48;
emission_factor = 0.2016;
A = 0;
B = 7000;
C = 0;
o_var = 0;
FOM = 23;
pd_low = 160;
RD = 960;
DD = 2;
pu_high = 160;
RU = 960;
UD = 2;

parameter gascost(k);
gascost(k) = gas_price;

parameter co2cost(k);
co2cost(k) = co2_price;

FC(k) = gascost(k);

parameter el_price(k) / 
1 42.7 
2 37.278 
3 24.111 
4 26.251 
5 17.352 
6 29.804 
7 41.409 
8 56.093 
9 61.87 
10 64.761 
11 63.998 
12 65.562 
13 63.431 
14 62.999 
15 60.304 
16 55.326 
17 53.49 
18 53.028 
19 53.069 
20 49.02 
21 50.694 
22 52.208 
23 54.098 
24 48.408 / ;

lambda(k) = el_price(k);

lambda(k) = el_price(k);

parameter VC(k) variable cost of generation at maximum efficiency in [Euros per MWh];
VC(k) = FC(k)/eta_max + co2cost(k)*(emission_factor/eta_max) + o_var;

parameter VC_min(k) variable cost of generation at part-load operation in [Euros per MWh];
VC_min(k) = FC(k)/eta_min + co2cost(k)*(emission_factor/eta_min) + o_var;

parameter part_load_penalty(k) cost penalty for part load operation in [Euros per MWh];
part_load_penalty(k) = VC_min(k) - VC(k);

variables
p(k) power output at the end of period k
p_avg(k) Average power output in period k
profit total profit over all periods k ;
binary variable
v(k) 0 or 1 variable which is equal to 1 if the unit is online in k
y(k) 0 or 1 variable which is equal to 1 if the unit is started up at the beginning of k
z(k) 0 or 1 variable which is equal to 1 if the unit is ramped down at the beginning of k
x(k) 0 or 1 variable which is equal to 1 if the unit is operating in part-load at the beginning of k;

equation Low_lim_power_1(k) ;
Low_lim_power_1(k).. p(k) =g= p_min*[v(k) - sum(kk$([ord(kk) gt ord(k)] and [ord(kk) le ord(k) + DD]), z(kk)) - sum(kk$([ord(kk) le ord(k)] and [ord(kk) ge (ord(k) - UD +1)]), y(kk))] +
sum(kk$([ord(kk) ge (ord(kk) le ord(k) + DD)] and [ord(kk) ge (ord(kk) ge (ord(k) - UD +1))], y(kk)))] +
sum(kk$([ord(kk) ge (ord(kk) le ord(k) - UD +1)])], y(kk))] +
sum(kk$([ord(kk) ge (ord(kk) ge (ord(k) - UD +1])], y(kk))])) +
sum(kk$([ord(kk) le ord(k)] and [ord(kk) ge (ord(k) - UD +1)]), y(kk)) * sum(i$(ord(i) eq ord(k) - ord(kk) +1), pu(i)) )

equation Low_lim_power_2(k) ;
Low_lim_power_2(k).. p(k) =g= p_min*[v(k) - sum(kk$([ord(kk) gt ord(k)] and [ord(kk) le ord(k) + DD]), z(kk)) - sum(kk$([ord(kk) le ord(k)] and [ord(kk) ge (ord(k) - UD +1)]), y(kk))] +
sum(kk$([ord(kk) ge (ord(kk) le ord(k) + DD)] and [ord(kk) ge (ord(kk) ge (ord(k) - UD +1)]), y(kk)))] +
sum(kk$([ord(kk) ge (ord(kk) le ord(k) - UD +1)])], y(kk)) * sum(i$(ord(i) eq ord(k) - ord(kk) +1), pu(i)) )

equation up_lim_power_3(k) ;
up_lim_power_3(k).. p(k) =l= sum(kk$([ord(kk) le ord(k)] and [ord(kk) ge (ord(k) - UD +1)]), y(kk)) * sum(i$(ord(i) eq ord(k) - ord(kk) +1), pu(i)) + p_max*[v(k) - sum(kk$([ord(kk) le ord(k)] and [ord(kk) ge (ord(k) - UD +1)]), y(kk))]

equation up_lim_power_4(k) ;
up_lim_power_4(k).. p(k) =l= sum(kk$([ord(kk) ge ord(k)] and [ord(kk) le ord(k) + DD)], z(kk)) * sum(i$(ord(i) eq ord(kk) - ord(k)), pd(i))) + p_max*[v(k) - sum(kk$([ord(kk) ge ord(k)] and [ord(kk) le ord(k) + DD]), z(kk))]

equation lim RU_5(k) ;
lim RU_5(k).. [p(k) - p(k-1)] =l= p_max * sum(kk$([ord(kk) ge ord(k)] and [ord(kk) ge ord(k) - UD +1)]), y(kk)) + RU*[v(k) - sum(kk$([ord(kk) ge ord(k)] and [ord(kk) ge ord(k) - UD +1)]), y(kk))]

equation lim RD_6(k) ;
lim RD_6(k).. p(k-1) - p(k) =l= p_max * sum(kk$([ord(kk) ge ord(k)] and [ord(kk) le ord(k) + DD -1)], z(kk)) + RD*[v(k-1) - sum(kk$([ord(kk) ge ord(k)] and [ord(kk) le ord(k) + DD -1)], z(kk))]

equation con_bin_7(k) ;
con_bin_7(k).. y(k) - z(k) =e= v(k) - v(k-1);

equation con_bin_8(k) ;
con_bin_8(k).. v(k) =g= sum(kk$([ord(kk) ge ord(k)] and [ord(kk) ge ord(k) - UD +1)]), y(kk));

equation con_bin_9(k) ;
con_bin_9(k).. v(k) =g= sum(kk$([ord(kk) ge ord(k)] and [ord(kk) le ord(k) + DD]), z(kk));

equation overlap_10(k) ;
overlap_10(k).. y(k) + sum(kk$([ord(kk) ge ord(k)] and [ord(kk) le ord(k) + DD + UD -1]), z(kk)) =l= 1 ;
equation overlap_11(k) ;
overlap_11(k).. p(k) =g= pu_high* [sum(kk$(ord(kk) gt ord(k) and ord(kk) le ord(k) + DD)), z(kk)) + sum(kk$([ord(kk) le ord(k) and ord(kk) ge ord(k) - UD + 1]), y(kk)) - 1];

equation overlap_12(k) ;
overlap_12(k).. p(k) =g= pd_low* [sum(kk$(ord(kk) gt ord(k) and ord(kk) le ord(k) + DD)), z(kk)) + sum(kk$([ord(kk) le ord(k) and ord(kk) ge ord(k) - UD + 1]), y(kk)) - 1];

equation pavg_15(k) ;
pavg_15.k.. p_avg(k) =e= [p(k) + p(k-1)]/2;

*** Equations 16 - 17 determine whether the power plant is in part-load operation or not ***

equation partload_16(k) ;
partload_16.k.. (p_max - p(k)) =l= x(k)*(p_max) + (1 - v(k))*p_max;

equation partload_17(k) ;
partload_17(k).. x(k) =l= v(k);

*** Objective Function of the Optimisation Problem (maximise profits of the generator in Euros) ***

equation objective ;
objective.. profit =e= sum(k, lambda(k)*p_avg(k) - [A*v(k) + p_avg(k)*VC(k) + x(k)*part_load_penalty(k) + C*z(k) + B*y(k)]);

Model unit_com_test / all /
unit_com_test.optfile =1;
Solve unit_com_test max profit using MIP;

parameter hourly_rev(k);
hourly_rev(k) = lambda(k)*p_avg.l(k);

parameter hourly_cost(k);
hourly_cost(k) = A*v.l(k) + p_avg.l(k)*VC(k) + x.l(k)*part_load_penalty(k) + C*z.l(k) + B*y.l(k);

parameter hourly_profit(k);
hourly_profit(k) = hourly_rev(k) - hourly_cost(k);

parameter full_load_hours;
full_load_hours = sum(k, p_avg.l(k))/p_max;

parameter load_factor;
load_factor = full_load_hours/card(k);

parameter startups;
startups = sum(k, y.l(k));

parameter shutdowns;
shutdowns = sum(k, z.l(k));

parameter partloadhours;
partloadhours = sum(k, x.l(k));

parameter var_cost;
var_cost = sum(k, p_avg.l(k)*VC(k));

parameter startupcost;
startupcost = sum(k, B*y.l(k)) ;

parameter shutdowncost;
shutdowncost = sum(k, C*z.l(k)) ;

parameter partloadcost;
partloadcost = sum(k, x.l(k)*part_load_penalty(k));

parameter tot_profit;
tot_profit = profit.l - FOM * 1000 * p_max/365;

display hourly_rev, hourly_cost, hourly_profit, full_load_hours, load_factor, startups, shutdowns, var_cost, shutdowncost, startupcost, partloadcost ;
Acronyms, abbreviations and units of measure

Acronyms and abbreviations

<table>
<thead>
<tr>
<th>Acronym</th>
<th>Description</th>
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<tbody>
<tr>
<td>a</td>
<td>year</td>
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<tr>
<td>CCGT</td>
<td>Combined-cycle gas turbine</td>
</tr>
<tr>
<td>CHP</td>
<td>Combined heat and power generation</td>
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<tr>
<td>CO₂</td>
<td>carbon dioxide</td>
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<tr>
<td>EU-ETS</td>
<td>European Union Emissions Trading Scheme</td>
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<tr>
<td>FOM</td>
<td>Fixed operation and maintenance costs</td>
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<tr>
<td>GAMS</td>
<td>General Algebraic Modelling System</td>
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<td>h</td>
<td>hour</td>
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<tr>
<td>ICT</td>
<td>Instrumentation and control technology</td>
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<tr>
<td>k</td>
<td>thousand</td>
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<tr>
<td>NPV</td>
<td>Net present value</td>
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<tr>
<td>REN</td>
<td>Renewable Energies</td>
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<tr>
<td>t</td>
<td>tonne</td>
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<tr>
<td>WACC</td>
<td>Weighted average cost of capital</td>
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Units of measure

<table>
<thead>
<tr>
<th>Unit</th>
<th>Description</th>
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</thead>
<tbody>
<tr>
<td>GW</td>
<td>gigawatt</td>
</tr>
<tr>
<td>GWh</td>
<td>gigawatt hour</td>
</tr>
<tr>
<td>kW</td>
<td>kilowatt</td>
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<tr>
<td>MW</td>
<td>megawatt</td>
</tr>
<tr>
<td>MWh</td>
<td>megawatt hour</td>
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</table>
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