Combining LP and MIP approaches to model the impacts of renewable energy generation on individual thermal power plant operation

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***Abstract*—A common method of modeling the operation of power plants in competitive electricity markets is mixed integer programing (MIP). Despite the advantages of the method, it requires solving an NP-hard problem. Modeling all of Europe with several thousand power plants thus would take enormous computational power. In order to reduce problem complexity in this large scale system, while still including detailed behavior of individual plants, we develop an approach where MIP is applied only to focus regions that are analyzed in detail combined with a linear programming model (LP) of all other regions. This combination allows for the prediction of impacts of renewable integration all over Europe on individual power plants in Germany. The results indicate that operational hours of thermal power plants will go down significantly, while the number of start-ups will increase. In order to avoid curtailments of renewable power, enhancements in power plant flexibility will be inevitable.**

***Index Terms*—Unit Commitment, Renewable Energies, Power System Modeling, Entso-E, Power Plant Dynamics.**

I. Nomenclature

Indizes and sets

$m \in \mathcal{M}$	Spinning and nonspinning reserves, $\mathcal{M}$ ={Primary-, Secondary-, Tertiary Reserve}
$t \in \mathcal{T}$	Time step, $\mathcal{T} = \{1, ..., 8760\}$
$v \in \mathcal{V}$	Country, $\mathcal{V} = \{EU27, NO, CH\}$
$n_v \in \mathcal{N}_v$	Neighboring country of country v
$z \in \mathcal{Z}$	Power transformation process
$a \in \mathcal{A}$	Aggregated controllable power plant, $\mathcal{A} \subset \mathcal{Z}$
$j \in \mathcal{J}$	Single power plant, $\mathcal{J} \subset \mathcal{Z}$
$r \in \mathcal{R}$	Aggregated must-run power plant, $\mathcal{R} \subset \mathcal{Z}$
$s \in \mathcal{S}$	Electric storage, $\mathcal{S} \subset \mathcal{Z}$

Variables

$b_{v,j}(t)$	State of single power plant j in country v, $b_{v,j}(t) \in \{0, 1\}$
$c^{up}_{z,v}(t)$	Costs for startup
$c^{var}_{z,v}(t)$	Variable production cost
$d_{z,v}(t)$	Start-up of process z
$f_{v,n_v}(t)$	Cross border power exchange
$g_{a,v}(t)$	Share of power plants online of the aggregated power plant block a
$h_{m,z,v}(t)$	Provision of type m reserve
$l_{s,v}(t)$	Energy content of storage s
$p_{z,v}(t)$	Power output of transformation processes z

Parameters

$\gamma_{m,\mathrm{DE}}(t)$	Requirement for type m reserves in DE
$\phi_v(t)$	Average hourly production from dam storage plants
$\delta_v(t)$	Electricity demand in country v
$\eta_{z,v}$	Efficiency of process z
$\zeta_{z,v}$	Specific costs [€/MW] for startup of aggregated power plant a or single power plant j
$\mu_{a,v}$	Minimum power output as share of $g_{a,v}(t_m)$
$\sigma_{z,v}$	Variable production costs of process z

II. Introduction

Climate change, the scarcity of resources, as well as an increasing public aversion to nuclear energy are leading to major changes in many power supply systems in the world. Former hydro-thermal power systems are increasingly interspersed with intermittent renewable power sources such as wind or solar. This transformation process has to be well understood in order to avoid mistakes leading to high costs or even system failures. Modeling and simulation is a powerful tool for analyzing potential future scenarios. All organizations involved, from grid operators to operators of individual power plants, wish to know how to best face the challenges from increasing intermittent generation. The focus of this paper is on describing a model that allows to investigate effects from renewable power integration all over Europe on individual thermal power plants in Germany. Using this model, we analyze which technical measures could improve the profitability of individual plants as well as increase the overall efficiency of the future system.

Many studies conducted so far focus on either large interconnected systems or detailed modeling of individual power plants in geographically small regions. Models that analyze the behavior of large interconnected systems tend to use a pure linear programming approach (LP). These models allow the investigation of transcontinental power systems with an aggregated modeling of power plants in each region. Influences from intermittent energy sources on necessary grid extension [1], the change in electricity mix and emissions [2], or optimal placement of system components [3] can be examined employing this method. In contrast, studies that focus on more technical details and the binary state of power plants use a mixed integer programing (MIP) approach as described in [4]. As the latter approach is NP-hard, it can only be applied to a limited number of power plants. Thus, studies usually focus on national power systems while neglecting international power exchange, e.g. [5].

In order to take the advantages of both approaches while overcoming the disadvantages, we provide an approach to combine them in this paper. We model all German power plants individually with an MIP approach while integrating all remaining EU-27 countries and Norway and Switzerland with an LP approach. This allows us to investigate the dynamics of individual power plants within a model containing fossil and renewable power, storage, as well as international power exchange.

This article is organized as follows: We start with a formal description of the suggested model approach followed by a description of data which were used. In order to provide an idea about computational effectiveness of the proposed method we have a table with calculation times. We then show results that were obtained for future electricity generation in Germany and dynamics of individual power plants and conclude the paper with an outlook on possible future work.

III. Model Formulation

We assume that power plants in a competitive environment are operated with the goal of profit maximization. We further assume a perfect electricity market i.e. the overall costs of electricity supply are minimized. Costs include variable operational costs (including fuel and wear-and-tear) as well as costs for power plants start up. Therefore, the unit commitment can be stated according to [4]:

$$\min c = \min \sum_z \sum_v \sum_t [c^{var}_{z,v}(t) + c^{up}_{z,v}(t)] \tag{1}$$

The components of this functions are:

$$c^{up}_{z,v}(t) = d_{z,v}(t) \cdot \zeta_z \tag{2}$$

$$c^{var}_{s,v}(t) = p_{s,v}(t) \cdot \sigma_{s,v} \tag{3}$$

Variable costs of single power plants $c^{var}_{j,v}(t)$ are quadratic in $p_v(t)$ and can be approximated linearly according to [4]. The definition of $c^{var}_{a,v}(t)$ is presented in equation (15).

The main restriction that is valid for all nodes is the satisfaction of demand in every time step. Power $p_{z,v}(t)$ can be provided from storage units, power plants, or through international power exchange $f_{v,n_v}(t)$.

$$\sum_z p_{z,v}(t) + \sum_{n_v} f_{v,n_v}(t) \geq \delta_v(t) \tag{4}$$

Starting costs for single power plants are considered through an auxiliary variable $d_{j,v}(t)$ in equation (2), which is set to 1 for each startup process in equation (5), where $b_{j,v}$ is the binary state of each individual plant.

$$d_{j,v}(t) \geq b_{j,v}(t) - b_{j,v}(t-1) \tag{5}$$

The constraints on operation, e.g. ramping constraints, are not described here in detail but a description of the approach can be found in [4]. Additional equations are implemented to model the requirement for spinning reserves m in the focus region, DE in our case, of the model. These include primary, secondary, as well as tertiary controls according to [6]:

$$\sum_z h_{z,m,\mathrm{DE}}(t) \geq \gamma_{m,\mathrm{DE}}(t) \tag{6}$$

As forecast errors lead to an increased requirement for spinning reserves, $\gamma_{m,\mathrm{DE}}(t)$ is not time constant but linearly dependent on the hourly feed-in from wind power as analyzed e.g. in [7].

The provision of spinning reserves leads to an additional constraint in power plants' operation:

$$p_{\min,j} \cdot b_j(t) \leq p_j(t) + \sum_m h_{j,m,\mathrm{DE}}(t) \leq p_{\max,j} \cdot b_j(t) \tag{7}$$

The maximum output of spinning reserves from power plants $h_{\max,j}$ is defined by the maximum ramping rates of the plants. Parameter variations of $h_{\max,j}$ and $p_{\min,j}$ and their effect on major simulation results can be found in section V.

Storage units can also provide spinning reserves whereby the storage level $l_{s,v}(t)$ has to stay within limits even in case of reserve activation. This constrains the maximum turbine or pump power $p_{s,v}(t)$ as defined by the following equations:

$$0 \leq h_{s,v}(t) + p_{s,v}(t) \leq p_{\max,s,v} \tag{8}$$

$$0 \leq l_{s,v}(t) + h_{s,v}(t) + p_{s,v}(t) \leq l_{\max,s,v} \tag{9}$$

$$l_s(t) = l_{s,v}(t-1) + p_{s,v}(t) \tag{10}$$

$$l_{\min,s,v} \leq l_{s,v}(t) \leq l_{\max,s,v} \tag{11}$$

To model the LP modeled regions and the international electricity exchange, additional restrictions have to be implemented:

$$0 \leq p_{a,v}(t) \leq p_{\max,a,v} \tag{12}$$

$$f_{v,n_v}(t) \leq f_{\max,v,n_v} \tag{13}$$

To estimate the startup costs of aggregated power plants, a continuous state variable $g_{a,v}$ is introduced according to [8] and [9]:

$$\mu_{a,v} \cdot g_{a,v}(t) \leq p_{a,v}(t) \leq g_{a,v}(t) \tag{14}$$

Lower efficiency in part load can also be modeled with the help of this continuous state variable:

$$c_{a,v}^{var}(t) = \frac{\mu_{a,v} \cdot g_{a,v}(t)}{\eta_{\min,a,v}} + [p_{a,v}(t) - \mu_{a,v} \cdot g_{a,v}(t)] \cdot \frac{\frac{1}{\eta_{\max,a,v}} - \frac{\mu_{a,v}}{\eta_{\min,a,v}}}{1 - \mu_{a,v}} \quad (15)$$

Starting new power plants means increasing $g_{a,v}$, which leads to startup costs according to equation (2) through the following constraint for $d_{a,v}(t)$:

$$d_{a,v}(t) \geq (g_{a,v}(t) - g_{a,v}(t-1)) \quad (16)$$

IV. Input Data and Validation

The model formulation described in the previous section is used to investigate the integration of intermittent power sources in the European context. The major focus were the effects on individual power plants in Germany. Fig. 1 shows major data inputs and outputs of the optimization model.

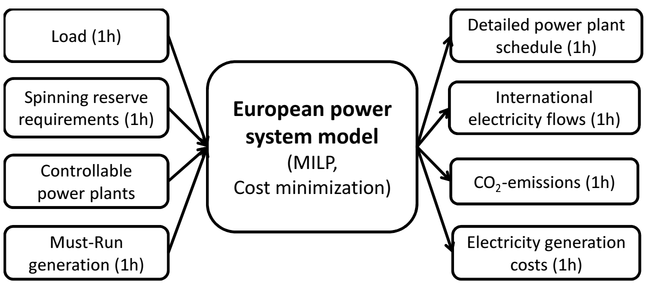


Fig. 1. Major input and output of simulation model

The input data that were used to set up the model are:

- Demand: Hourly load data for all countries [10]
- Conventional power plant infrastructure for Europe [11]
- Net transfer capacities [12]
- Parameters of 190 conventional individual power plant blocks in Germany [13] combined with expert knowledge of operators
- Installed capacities of renewable energy sources from the European Union [14]
- Hourly feed-in characteristics generated from ISET provided by SIEMENS [15].

To the best of our knowledge, there is no better public data to model Europe employing our approach. If applied to other regions of the world, model data should constitute the same elements but the level of detail can vary to some extent.

The model results reproduce the real world data quite well. Annual electricity generation by primary energy carriers were compared to real world data [16] for Germany in the year 2011 as displayed in Table I. Deviations are below 5 % for all types of power plants. Wind and solar power generation is modeled using historic weather data of 2007 which explains the deviation of renewable generation from the real world generation in 2011.

TABLE I
Comparison of model results with real world data for 2011

Resource	Real data [TWh]	Model result [TWh]	Deviation [%]
Nuclear	110.2	105.3	-4.3
Lignite	153.0	148.7	-2.8
Coal	116.3	111.4	-4.4
Gas	85.7	89.4	4.1
Renewables	122.4	116.3	5.0

V. Scenario Results

Several scenarios are calculated to explore different potential developments from 2011 to 2023 which is the year when the last nuclear power plant in Germany will be switched off. The calculation of an entire year is performed using a rolling horizon as depicted in Fig. 2. In one optimization process, 36 hours are calculated, of which 24 hours are kept as the optimal solution. The other 12 hours are calculated again in the next optimization process.

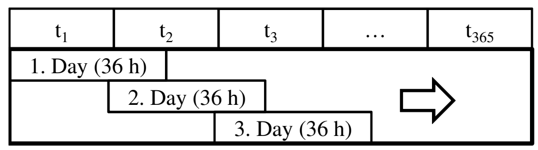


Fig. 2. Simulation employing rolling horizon

The results presented in this paper should provide an impression of the model's possibilities and raise awareness of potential problems with the integration of renewable energies. More detailed results from different scenarios can be found in [17]. In order to show the calculation speed, Table II contains the range of computation times for major scenarios. Despite having fewer power plant blocks in 2023, the computation time is significantly higher. The increase might result from more time steps with low residual load due to higher feed-in of renewable power sources in 2023. These lower residual loads lead a higher number of possible commitment options, which requires more compuation time. The calculation was performed on a DELL 2x Xeon (E5630@2.53GHz 4-Core) with 24GB RAM under MS Windows7 64bit using CPLEX 12.2 64bit. The cut-off gap of the solver was set to 0.5 %.

TABLE II
Range of computation time with CPLEX 12.2

Year	Individual blocks	36 h steps	1 year	load characteristic
2011	189	5 s-5 min	app. 5 h	high residual loads
2023	142	5 s-25 min	app. 9 h	low residual loads

The upper part of Fig. 3 shows the hourly production of all power plants in Germany for two sample weeks in 2020: One winter week which is characterized by high wind and low solar generation and a summer week where it is the other way round. It illustrates that there will be times with negative residual loads in winter as well as in summer. This overproduction either has to be exported to other countries or curtailed. Power supply systems also require control power

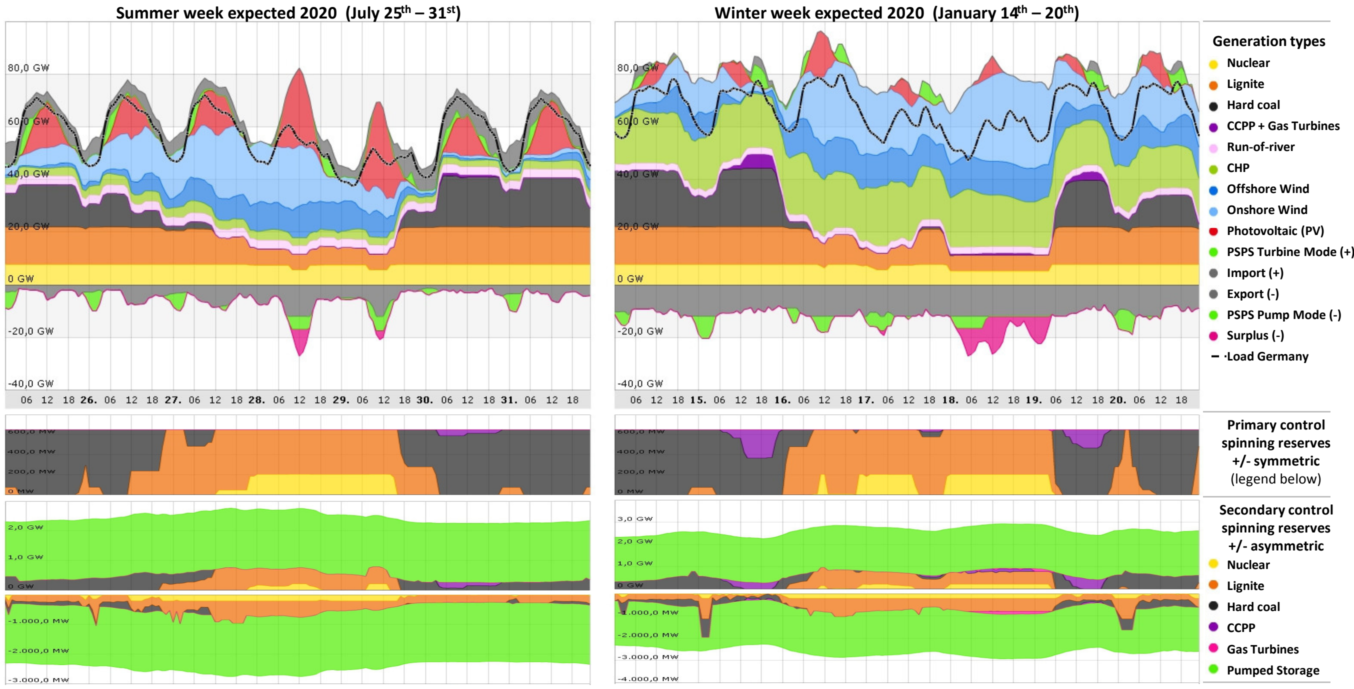


Fig. 3. Calculated generation of electricity (upper part) and spinning reserves (lower part) from power plants in Germany for a summer/winter week in 2020

which is primary, secondary, and tertiary reserves in the European system. The primary and secondary reserves are spinning reserves and have to be provided by online power plants or pumped hydro storage units. A higher level of wind and PV power will lead to higher forecast errors and therefore to a higher requirement of spinning reserves. The secondary reserves were assumed to increase by 1.5 % of wind power output in every time step. The lower part of Fig. 3 shows the provision of spinning reserves, seperated into generation technologies. In times of very high wind and solar production, fossil power plants are online merely to provide these system services. This situation, however, would be inefficient from an economic and an environmental perspective.

A main motivation for this modeling approach was to gain insight into the dynamics of single power plants within large systems. Fig. 4 shows the simulated hourly electricity production and spinning reserves of the 500 MW hard coal plant Rostock, which was used as a reference plant.

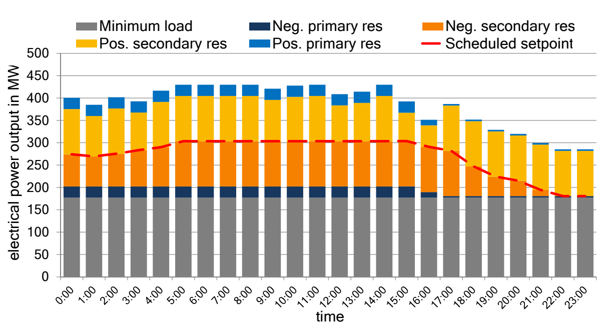


Fig. 4. Calculated 24 h schedule for a single 500 MW hard coal reference plant including spinning reserves for each time step

The major parameters defining power plant flexibility - maximum ramping and minimum load - were varied in order to measure their effectiveness in several case studies. Fig. 5 shows the resulting operation range for three different parameter configurations. The effects on the annual plant utilization, start-up characteristic, and hence the partial load efficiency are investigated in 1-year scenarios.

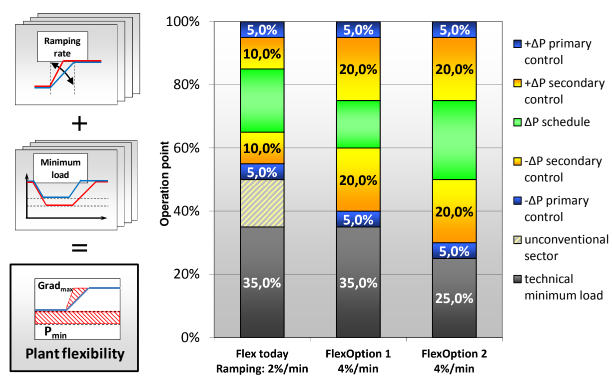
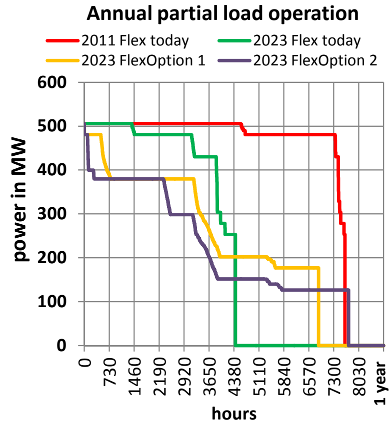
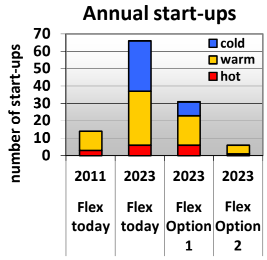


Fig. 5. Case studies for the hard coal reference plant in Germany: Enhancement of flexibility by reduced minimum power output and increased ramping which makes it possible to provide more secondary reserves

Fig. 6 shows that the annual plant utilization is reduced dramatically by 2023, while the partial load characteristic does not change significantly without enhancements. The plant is still operating at full load for most of the time. Upgrading the flexibility leads to more operational hours and fewer start-ups, improving the profitability of the power plant. The hourly power plant output obtained in these case studies was used as an input for a more detailed thermodynamic model in order to investigate wear-and-tear in more detail (see [18]).





Annual operating hours

[h]	2011 Flex today	2023 Flex today	2023 Flex Option 1	2023 Flex Option 2
full load	7399	3977	4024	3646
in operation	7629	4423	6860	7738

Fig. 6. Results for the reference plant in Germany with different design parameters in 2023 compared to today's flexibility in 2011

The model results indicate that new thermal power plants should have higher flexibility and in particular a continuous load change flexibility in partial load. These and other findings can provide guidance to relevant decision makers in public as well as private institutions concerned with restructuring the power system.

VI. Conclusion and Outlook

This paper describes a method that allows us to analyze power systems with hundreds of single power plants at different levels of detail. The impacts of integrating renewable power sources into large interconnected power systems on the operation of an individual power plant can be simulated.

Through analyzing the most common scenarios for the development of renewable power generation in Europe, several problems arising from the intermittent character of wind and solar power have been identified. Operational hours of thermal power plants will decrease and there will be times when fossil power plants are online only to provide spinning reserves, while at the same time renewable power has to be curtailed. Enhancing power plant flexibility is one option to face this challenge. The effects of different design parameters on the plants' operational characteristics were tested in potential future scenarios. The methodology developed and the results obtained can help to improve future power plant design leading to a economic, efficient, and reliable power supply system.

Despite considerable improvement of existing modeling approaches for investigations on future power systems, there are many directions for further research. Improvements of the modeling approach could be integrating load flow calculations, coupling of electricity and heating sector in generation and demand, as well as integrating a module for upcoming demand side management. Research into these directions will be conducted at the authors' institutes.

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