Simulation of cogeneration combined cycle plant flexibilization by thermochemical energy storage

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Abstract:

In the course of the “Energiewende” the German electricity market is undergoing major changes. The state-aided priority of renewable generation has led to a significant decline in electricity prices. This reduces the profit margin of cogeneration units, but on the other hand it increases the economic impact of flexibilization potential like heat storage systems.

In this work, a 100 MWel combined-cycle power plant supplying heat and power to a paper mill is investigated. Currently the plant is operated heat-controlled and is therefore unable to react to changing electricity spot prices. With the integration of a heat storage, the plant is enabled to switch to power-controlled mode.

To evaluate the technical impact of the storage, the plant and a thermochemical MgO/Mg(OH)$_2$ storage are modelled using the stationary process simulation tool EBSILON. Different operation modes are investigated and results are used to derive a mixed integer linear programming model to optimize the operation of the plant/storage system. Taking into account measurements of the heat demand and EPEX spot prices, a benefit of some 100k €/a is possible compared to normal operation mode.

Keywords:
Cogeneration, Storage, thermochemical, Combined Cycle, Industrial Power Plant, MILP, EBSILON Professional

1. Introduction

1.1. The German “Energiewende” and its impact on the market

With the Nuclear Phase-out \cite{1} and the Renewable-Energy-Act (REA) \cite{2} the German government has set an ambitious roadmap to transform the German electricity generation from fossil- and nuclear-to renewable-based within the next 40 years. Beginning in 2000, the German government started to guarantee feed-in tariffs for renewable (namely photovoltaic, wind on- and offshore, biomass, hydro and geothermal) generation. The feed-in tariffs are decreasing by fixed rates for later built plants to support innovation. The REA has seen multiple revisions, the most recent in 2014 \cite{3}. Aside the fixed feed-in tariffs the REA gives renewables a feed-in priority to the grid.

This created attractive conditions for investments in renewable generation with interest rates far above the prime rate and very low risk. This lead to an extensive increase in renewable generation capacity over the past 15 years. Figure 1 shows the development of the German generation capacity since 1991. Since the implementation of the renewable energy act in 2000, the overall generation capacity has grown by 65 GW or 50 %. The share of renewable capacity has reached 50 % in 2015. At the same time, there has been little change on the demand side \cite{4}. This results in a significant decrease of electricity market prices. Within the last ten years, the yearly average of the EPEX day ahead price dropped by 50 % \cite{5}. Since the German electricity market is an energy only market, this has led to significant economic trouble for conventional generation units.
This also includes heat and power co-generation units, that are often operated heat controlled and are therefore unable to react to decreasing electricity prices. Things are even more critical for gas fired units as on the one hand, these plants have relatively high fuel costs and are therefore more sensitive to falling electricity prices. On the other hand, the combined cycle concept has a higher fixed share of electricity generation. While a directly fired steam power plant can theoretically produce district or process heat at an electrical net output of zero (by bypassing the steam turbine), a combined cycle plant has a minimum electrical generation of 30 – 50 % of the fuel energy input, as the gas-turbine has to be operated. This results in an inherent motivation for the flexibilization of these plants by decoupling heat and power generation at least for a defined period, giving the plant the chance to react to market price fluctuations while still providing sufficient heat output.

Figure 1: Installed capacity in the German power grid over the last 25 years, adopted from [4]

1.2 Motivation for flexibilization of cogeneration-plants

Falling prices and less operating hours are some of the challenges conventional power generation is facing within the “Energiewende”. Another one is the fluctuations of the renewable generation, resulting in more frequent and higher fluctuations of the residual load covered by conventional power plants. This effect can already be seen in the present [4] and is expected to increase in the future. It will result in an increased demand for control power. The German Energy Agency expects the demand for the different kinds of control power to double within the next 15 years. In many cases this control power can only be provided by conventional power plants. [6]

However, conventional plants are facing lower revenues and less operating hours while on the other hand their flexibility and controllability is needed more than ever. With an installed capacity of approximately 30 GW, co-generation units make up a third of the overall German conventional generation [7]. Today these plants are often operated heat-controlled and are therefore rather inflexible. Accessing this potential is one of the key issues for the integration of the renewables into the German grid within the next decade. One of the biggest challenges in this respect is finding a way to guarantee the heat supply efficiently while at the same time being able to react on fluctuations on the electricity market.

Thermal energy storage can be a cornerstone in this ambitious plan. This can already be seen as several German municipal energy suppliers are beginning to use storage in co-generation plants. All of these plants use sensible water storage systems at a size of 1…-2 GWh and produce heat for district heating at temperature levels below 100 °C (e.g. [8], [9], [10]). This storage system is unrivaled simple and cheap for temperatures below 100 °C, but cannot be applied at higher temperature levels.
2. Case study

2.1 Combined heat and power generation and investigated plant

Combined heat and power generation is a common concept to increase the degree of fuel utilization. It is independent from the type of fuel used. All types of steam power plants can be equipped with co-generation. Gas turbines or engines can be equipped with waste heat recovery for heat generation. In this paper, the focus here is on co-generation within CC power plants.

CC plants as shown in Figure 2 consist of a gas turbine and a heat recovery steam generator driving a steam turbine. State of the art CC plants reach live steam temperatures up to 600 °C and have an overall efficiency of >60 %. In most applications, heat for district heating or industrial applications is drawn from the steam turbine. There are two ways for heat extraction from steam turbines:

- Extraction condensing turbines work like normal condensation turbines with a heat exchanger for condensation at low pressure at the back end of the turbine. Steam for process or district heat is drawn from one or multiple extractions between turbine stages. As the extraction valves can be controlled or even closed, this turbine can be operated like a normal turbine when no heat is needed and the heat/power ratio is flexible within a certain range.

- Back pressure turbines do not necessarily have a heat sink at the low pressure end. At the end of the turbine the steam is in most cases superheated at elevated pressure and is used for process or district heating directly or via heating condenser. Unlike the extraction turbine, this type is much more inflexible as the heat/power ratio is fixed to a certain value meaning that a certain electricity generation is always related to a specific heat generation.

In the investigated plant an extraction turbine with ports at 10 and 5 bar is used, allowing the plant to react flexible to changing heat demands. The steam turbine has an electric gross output of about 30 MW and supplies up to 100 MW of heat to a nearby paper mill, mostly as slightly superheated steam on a 5 bar line. The heat recovery steam generator is a simple one pressure natural circulation boiler with live steam parameters of 90 bar and 530 °C. It is fuelled by heat from a GE 6 FA gas turbine, capable of an electric gross output of 80 MW and an additional gas firing with a peak fuel load of 30 MW.

Figure 2: Flow sheet of a simple natural gas combined cycle plant. 1: Gas turbine with generator, 2: Feed water tank, 3: Feed water pump, 4: Heat recovery steam generator (with economizer, evaporator and superheater), 5: Steam turbine and generator, 6: Condenser
2.2 Thermochemical energy storage

Above 100 °C, sensible heat storage using water (as mentioned above) is only possible at elevated pressures which has significant impact on the construction requirements, therefore other types of storage have to be considered.

Thermal energy storage

In literature (e.g. [11], [12]) typically three types of thermal energy storage systems can be found. Sensible storage store heat by temperature change of the storage media, latent heat storage uses a phase change of the storage material and thermochemical storage systems apply reversible chemical reactions for heat storage. While the first has a temperature gradient over the load cycle the latter two have theoretically constant temperatures for charge and discharge and are therefore especially suitable for steam generation. As mentioned already, sensible heat storage is already used on industrial scale. Latent and thermochemical heat storage are in a development state with little to no existing demonstration on industrial scale. Nevertheless, especially thermochemical storage has a huge potential, as there are cheap storage materials that make the storage of heat on a multi GWh scale possible. The most investigated thermochemical energy system is CaO/Ca(OH)$_2$. CaO is available in large scale and at very cheap prices resulting in storage material costs of ~15 ct/kWh. Anyway the chemical equilibrium of the CaO/Ca(OH)$_2$ system is at 500 °C at atmospheric pressure [13] and is therefore not suitable for application in co-generation temperature ranges.

The magnesium oxide/magnesium hydroxide system

A very similar system to CaO/Ca(OH)$_2$ is the magnesium/magnesium hydroxide system:

\[ MgO + H_2O \leftrightarrow Mg(OH)_2 + \Delta H_R \]  

Like CaO, MgO is found in large amounts in natural mineral deposits, therefore a similar cost structure for the raw material can be expected. The equilibrium of the system was discussed in several publications (e.g. [14], [15] and [16]). In this paper the approach by Kato [16] is applied:

\[ \ln \left( \frac{P_{eq}}{10^5} \right) = \frac{9376.5}{T_{eq}} + 17.369 \]  

The pressure dependence of the equilibrium is shown in Figure 3. A so called chemical heat pump effect can be realized by changing pressure between charge and discharge. In this paper, charging is performed at 0.5 bar while discharge is done at atmospheric conditions. This results in equilibrium temperatures of 245 °C for charging and 265 °C for discharging, respectively. Anyway, to guarantee reactivity a certain distance to the equilibrium is necessary. Therefore, the final discharging temperature is well below the charging temperature and there is no overall positive heat pump effect. Nevertheless, the temperature level and high energy density makes this system very interesting for industrial cogeneration applications.

The reaction enthalpy is calculated based on temperature dependent formation enthalpies using data from [17]:

\[ \Delta H_R = \Delta H_{F,Mg(OH)_2} - \Delta H_{F,MgO} - \Delta H_{F,H_2O} \]  

An average value at practical reaction conditions is -78 kJ/mol. Similar values can be found at [14], [15] and [16]. With a powder density of 0.5 t/m$^3$ this results in a storage density of about 200 kWh/m$^3$, which is about four times the storage density of the sensible water storage.
3. Modelling

Modelling of the power plant and storage system is done using EBSILON Professional, a commercial process simulation software [18]. EBSILON Professional is a stationary simulation tool for process simulation with a graphical user interface and a number of typical pre-implemented power plant components. For components not included in the standard library, programmable (Fortran) components can be used. Such components were used to model the storage system in this paper.

For the optimization of the storage operation, a Mixed Integer Linear Programming (MILP) tool was implemented in Matlab based on the process simulation results. Matlab is a high level commercial programming language developed by Mathworks, widely used in engineering applications [19].

In a first step the combined cycle plant is modelled in EBSILON Professional. After a validation of the plant model, the integration of the storage in the plant is investigated using EBSILON Professional. In a second step, a MILP-model of the plant is derived from the process simulation results. This model is implemented in Matlab and an optimization of the plant operation is performed using the measured heat consumption and 2014 electricity spot market prices.

3.1 Process simulation

As a basic step for the operation optimization the power plant and the storage are modelled in EBSILON Professional. These models are then combined and several operation modes are investigated to generate a data base for the MILP-optimization discussed in the following chapter.

Modelling of the existing site

Based on the geometry and operation data of the real site, a stationary process simulation model of the plant is created using EBSILON Professional. The model in the graphical user interface is shown in Figure 4. The gas turbine is modelled using manufacturer data from the VTU Gas Turbine Library [20]. The additional firing and the HRSG with the natural circulation system and injection coolers are modelled using plant geometry data. The steam turbine with governing stage is modelled according to Stodola law. The plant is operated in fixed pressure mode with a nozzle group control. To keep the temperature of the process steam in the 5 bar line constant, it is controlled by another injection cooler. In normal operation 90 % of the steam goes to the 5 bar line and only 10 % go to the last turbine stages and the condenser.

Figure 3: Pressure dependence of the chemical equilibrium for reaction (1). Data from [16]
Modelling of the storage

A simple balance model of the storage is implemented in EBSILON Professional using a Fortran-programmable component. The storage setup for the charging is shown in Figure 5. The core component is a fluidized bed reactor which is heated by live steam from the heat recovery steam generator through a bundled tube heat exchanger within the fluidized bed. Due to the fine particles in the MgO/Mg(OH)$_2$ system very little abrasion is expected and heating surfaces can be placed within the fluidized bed. The reactor is fed with Mg(OH)$_2$ from the top. The reactor is modeled using mass and energy balances under an estimation of full conversion and sufficient heat and mass transfer:

Mass balance of the reactor can be written as:

$$\dot{m}_{\text{Mg(OH)$_2$}} + \dot{m}_{\text{H}_2\text{O(g)},\text{in}} - \dot{m}_{\text{MgO}} - \dot{m}_{\text{H}_2\text{O(g)},\text{out}} = 0$$

(4)

The energy balance can be written as:

$$\dot{m}_{\text{Mg(OH)$_2$}} \cdot h_{\text{Mg(OH)$_2$}} + \dot{m}_{\text{H}_2\text{O(g)},\text{in}} \cdot h_{\text{H}_2\text{O(g)},\text{in}} + \dot{Q}_{\text{heating}} - \Delta H_R \cdot \frac{\dot{m}_{\text{Mg(OH)$_2$}}}{\dot{m}_{\text{MgO}}} - \dot{m}_{\text{MgO}} \cdot h_{\text{MgO}} - \dot{m}_{\text{H}_2\text{O(g)},\text{out}} \cdot h_{\text{H}_2\text{O(g)},\text{out}}$$

(5)

The temperature of the reactor is fixed to a value 50 K above (for charging) or below (for discharging) the equilibrium temperature (equation (2)) to ensure sufficient reactivity. Reactivity is assumed to be ideal at this conditions, chemical kinetics were neglected in the model. Especially for the hydration (discharging), literature is not conclusive about the reactivity of MgO [15], [16]. Recently, major improvement of the reactivity by doping with alkaline metals was reported [21]. This results were confirmed by first lab experiments at the Institute for Energy Systems, yet further research is necessary.
The Mg(OH)₂ is preheated in a two stage fluidized bed preheater. Fluidization media and heat carrier is nitrogen. The heat for the preheating comes from a fluidized bed cooler, which removes heat from the product MgO flow after the reactor. The heat transfer system is operated with nitrogen, since the presence of CO₂ in air would lead to magnesium carbonate formation and thus deactivation of the storage material. For increased efficiency the heat transfer system can be equipped with an additional heat transfer oil cycle to reduce the energy consumption of the fan.

![Diagram of storage configuration for charging mode with tanks and heat recovery system](image)

**Figure 5: Storage configuration for charging mode with tanks and heat recovery system**

**Basic setup for combined operation**

Figure 6 shows the integration into the CC process for charging the storage. Live steam from the HRSG is not expanded over the high pressure turbine but fed to the fluidized bed reactor. The live steam is cooled to 70 °C above the reaction equilibrium (50 °C for maintaining the reaction and 20 °C heat exchanger pinch point), which results in a steam temperature at the exit of about 310 °C and the corresponding heat is stored in the chemical storage material. Since reaction (1) creates a considerable amount of steam, it is mandatory for a high storage efficiency to use the condensation enthalpy of this steam in the paper mill. In charging mode, the storage is operated at 0.5 bar, to make use of the steam generated by the reaction, this steam has to be compressed to 5 bar. This can be achieved by using an injector pump driven by the cooled live steam, since this steam has to be throttled to 5 bar anyway. The 0.5 bar steam for fluidization is generated by throttling live steam to that pressure, the losses doing this are insignificant, as only 5 % of the steam are needed for fluidization and the steam is recompressed with the reaction steam in the injector pump and used in the paper mill. Of course, the storage can be operated parallel to the steam turbine. The live steam mass flow is then divided between turbine and storage.

In discharging mode, the storage is operated completely independent from the plant. Figure 7 shows a simplified setup for discharge operation. Condensate is fed into the system, the heat exchanger in fluidized bed is used as evaporator. 35 % of the slightly superheated steam at 5 bar is then used to fuel the reaction in the fluidized bed and is therefore throttled to the operation pressure of the bed at 1 bar. The fluidization is done by steam which is recycled using a compressor. The share of the 5 bar makeup is too small in this case to use an injector pump. The majority of the steam is transferred to the paper mill. The storage can be used to supply the paper mill while the CC plant is down, therefore...
reducing the electrical load to zero. Of course, parallel operation with the CC plant is also possible, creating higher possible electrical outputs from the CC, as less heat is drawn from the extraction turbine.

Figure 6: Flow sheet for charging of the storage. 100 % of the live steam are used in the storage, therefore the steam turbine is not shown

Figure 7: Configuration of the storage for discharge. Condensate is fed from the
3.2 Operation optimization

To estimate the additional profits gained from the heat storage, an optimization tool that determines the optimal plant operation schedule based on electricity prices and heat load is implemented in MATLAB. The objective of the tool is to solve the unit commitment and economic dispatch problem i.e. to decide which plant units should be operated at which power level. The main goal is to maximize the overall operation profit while meeting technical as well as other constraints like fulfilling the heat demand at any time [22]. A common approach to this is to formulate the problem as a mixed integer linear program by using binary operation variables (unit on = 1 or off = 0) and continuous variables as the input and output power levels of the units [22]. The following section describes the setup and solution of the mixed integer linear problem for the investigated plant.

First, the investigated power system is divided into its three main subsystems as shown in Figure 8: The combustion unit (consisting of the gas turbine, the HRSG and supplementary firing), the extraction unit and the storage unit. Each unit is assigned a binary operation variable \( \text{on}_{\text{Unit}} \) that defines its operating state (1 = on, 0 = off) in each time step. The storage unit gets an individual variable for the charge and the discharge mode, as only one mode can be active at a time. Furthermore, each unit gets continuous input and output variables in the form of its inlet and corresponding outlet heat-, power- and in case of the storage also mass flows. Based on these variables, each unit is modeled by equations and inequalities that can be divided into the following 3 groups.

**Operation range of the units:**

For each unit, a feasible operation area is defined by minimum and maximum values for their output variables, which can be derived from the plant simulation in EB SILON and limitations found in the manufacturer specification. For the gas turbine, a continuous power range between the minimum and maximum power output using the binary operating variable can be formulated as [23]:

\[
on_{\text{CU}} \times P_{\text{el,GT, min}} \leq P_{\text{el,GT}} \leq on_{\text{CU}} \times P_{\text{el,GT, max}}
\]

**Input/output relationships of the units:**

An important part is the formulation of linear relationships between the input (=consumption) and the output (=product) variables for the units. For this purpose, the EB SILON model is used to do a parameter variation of the output variables inside their feasible operation range and the associated committed input values are derived. Then a linear function is fitted to the resulting operation points. The resulting functions describe the load dependence of the efficiency-coefficients. In case of the gas turbine the obtained input/output-functions for the two products exhaust heat \( \dot{Q}_{\text{GT}} \) and electrical power \( P_{\text{el,GT}} \) can be described as a function of the committed fuel \( \dot{Q}_{\text{GT,Fuel}} \) with the following linear equations [23]:

\[
P_{\text{el,GT}} = \dot{Q}_{\text{GT,Fuel}} \cdot n_{\text{el}}(\text{Load}) = a \cdot on_{\text{CU}} + b \cdot \dot{Q}_{\text{GT,Fuel}}
\]

\[
\dot{Q}_{\text{GT}} = \dot{Q}_{\text{GT,Fuel}} \cdot n_{\text{th}}(\text{Load}) = c \cdot on_{\text{CU}} + d \cdot \dot{Q}_{\text{GT,Fuel}}
\]

**Startup of the Units:**

The third group of equations allows to model the start-up characteristics of the individual units. For this purpose, each of the three units receives another binary variable \( \text{start}_{\text{Unit}} \) which is 1 if the unit is starting up in a time step and zero else. For the combustion unit, a startup in the hour before normal operation can be forced by following logical equations [23]:

\[
on_{\text{CU}}(t) - on_{\text{CU}}(t - 1) - \text{start}_{\text{CU}}(t - 1) \leq 0 \quad \text{and} \quad on_{\text{CU}}(t) + \text{start}_{\text{CU}}(t) \leq 1
\]

These three sets of equations and inequalities form the main technical constraints of the optimization problem. Another primary constraint is meeting the heat demand of the paper mill at each time step using the heat from the condensing turbine and/or the storage system in charge or discharge mode. The heat demand is given as an input based on historical on-site measurement data with an hourly resolution.
3.3 Economics

The objective function of the optimization states the profit from the operation, which shall be maximized. Revenues originate from selling the electricity produced according to the hourly EPEX-spot market prices of 2014. The variable operation costs constitute of the expenses for fuel (including CO₂ costs) occurring in the gas turbine and supplementary firing, and costs for the plant startup and auxiliary power for the storage operation. Table 1 shows the main economic assumptions. Additional operating costs for the storage (e.g. for maintenance) are considered as a fixed annual expenditure. Investment costs for the storage are difficult to account for at the present state of the development. Therefore, this paper focuses on the possible revenue gained from storage operation, providing a target framework for possible investment costs.

Table 1: Basic assumptions for the operation optimization

<table>
<thead>
<tr>
<th></th>
<th>Value</th>
<th>Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electricity price 2014</td>
<td>EPEX spot market data (hourly)</td>
<td>[5]</td>
</tr>
<tr>
<td>Average natural gas cost 2014</td>
<td>23 €/MWₜₜ</td>
<td>[24]</td>
</tr>
<tr>
<td>Average CO₂– certificate cost 2014</td>
<td>7 €/tCO₂</td>
<td>[25]</td>
</tr>
<tr>
<td>Hot startup cost of the CC plant</td>
<td>2178 €/startup</td>
<td>[26]</td>
</tr>
</tbody>
</table>

The formulated mixed integer linear problem described above, is solved using the MATLAB intlinprog-solver. For each time step, a branch and cut algorithm decides which units are operated. Therefore, operation modes (setting of binary variables) as well as their output levels (setting the input and output variables) are applied, in order to maximize the profit, while taking into account the feasible operation areas, input/output- functions and startup constraints of the units and always fulfilling the heat demand of the paper mill.

For the year 2014 a long-term scheduling based on historical electricity prices and heat loads is carried out, using a rolling forecast method [27]: Assuming that the price of electricity is known ahead for the next 24 hours in every hour, the problem is solved. The result of the first hour is stored; the rest is discarded. The overall result is gained by optimizing over a 24-hour horizon for all 8760 hours of the year and concatenating the results.
4. Results and discussion

The results of the process simulation are presented for a reference case, while for the plant optimization actual heat-demand curves and corresponding spot market prices for electricity are used.

4.1 Process simulation

Model validation

In Table 2 the relative measured data for three operational cases (Normal operation, decreased heat and decreased power) are presented. These cases were selected because they are rather frequent within the typical operation of the plant and therefore sufficient stationary measurement data was available for validation. Figure 9 shows the results of the validation with errors well below 5% for all significant variables. A validation was also performed for a timespan of three months using hourly averaged measurement data. Due to the averaging of the measurement values for transient states of the plant, errors are a little higher in this case but still stay well below 10%. Therefore, the model of the plant can be considered accurate for the present state.

Table 2: Cases for validation

<table>
<thead>
<tr>
<th></th>
<th>Normal-operation</th>
<th>Decreased heat output</th>
<th>Decreased power output</th>
</tr>
</thead>
<tbody>
<tr>
<td>Relative gas turbine power [%]</td>
<td>100</td>
<td>97,1</td>
<td>85,6</td>
</tr>
<tr>
<td>Relative steam turbine power [%]</td>
<td>100</td>
<td>92,9</td>
<td>94,6</td>
</tr>
<tr>
<td>Relative additional firing [%]</td>
<td>100</td>
<td>35,3</td>
<td>107,1</td>
</tr>
<tr>
<td>Relative heat to paper mill [%]</td>
<td>100</td>
<td>69,0</td>
<td>100</td>
</tr>
</tbody>
</table>

Figure 9: Results of the process simulation validation

Integration of the storage

Figure 10 shows the energy flows of the steam cycle in normal and storage operation for heat demand of 83 MW by the paper mill. The gas turbine is run at full load for cases A) and B) in Figure 10. In normal operation (Chart A in Figure 10) the steam is extracted after the high pressure turbine. Since the expansion in the turbine leads to a higher enthalpy drop compared to the cooling in the storage and subsequent throttling, in normal operation the additional firing is used and an overall amount of...
128 MW of heat is available from the HRSG. When the storage is charged (Chart B in Figure 10), the additional firing is not in operation and only 100 MW are available. For the storage charging operation, that means only 17 MW are left for charging the storage. In the end, 11 MW can be stored in the MgO, resulting in a MgO-flow of 8.4 kg/s.

In discharging mode (Chart C in Figure 10), when the CC-plant is shut down, the 83 MW of process heat have to be supplied by the storage. Therefore, a mass flow of 45 kg/s of MgO is required. Thus approximately six hours of charging the storage correspond with one hour of discharging. As shown in Figure 7, approximately 35% of the steam generated from the storage have to be recycled to fuel the reaction.

It is challenging to define a reliable efficiency for the storage, that also considers the integration within the whole plant. A simplified approach for the complete system could be:

\[
\eta_{\text{Storage System}} = \eta_{\text{Storage System, charge}} \cdot \eta_{\text{Storage System, discharge}} = \frac{Q_{\text{process}} + Q_{\text{chem, storage}}}{Q_{\text{HRSG}} + P_{\text{el, storage}}} \cdot \frac{Q_{\text{chem, storage}} + P_{\text{el, storage}}}{83.1\,\text{MW}} = 89.6\%\quad (10)
\]

Another approach that does not take into account the process steam passed through the reactor is:

\[
\eta_{\text{Storage}} = \eta_{\text{Storage, charge}} \cdot \eta_{\text{Storage, discharge}} = \frac{Q_{\text{chem, storage}}}{m_{\text{Live Steam}} \cdot (h_{\text{Live Steam}} - h_{\text{Storage Exit}}) + P_{\text{el, storage}}} \cdot \frac{Q_{\text{process}}}{83.1\,\text{MW}} = 63.2\%\quad (11)
\]

Both approaches do not take into account that heat from a higher exergy level and electricity is transformed into process heat at low temperature level.

Figure 10: Heat flows for A) normal operation, B) storage charging operation and C) storage discharging operation for a heat demand of 83 MW from the paper mill

4.2 Plant operation

The plant operation optimization is performed under the assumption that all produced electricity is sold on the day ahead spot market. A dispatch scheme for a week in January 2014 is shown in Figure 11. At low electricity prices, the CC plant is shut down and heat for the paper mill is supplied by the storage (e.g. Jan 2, Jan 5 and Jan 6). At medium prices, the storage is charged. At high electricity prices it is not feasible to reduce the electrical output for heat storage, therefore the plant runs at
normal operation mode (also indicated by a higher electrical output). The assumption of a 24 h outlook on the energy market can also be seen as the prices at Jan 7 drop below those of Jan 6, but the storage capacity has been used on Jan 6, so no shut down is possible on Jan 7. The changing heat demand of the paper mill has a significant influence on the operation of the system, yet for clarity reasons it is not shown in Figure 11.

In the given model, the process heat is not accounted for in a monetary way. Process heat is just a constraint, that has to be met at any time. Therefore, the model is not capable of determining an absolute cash flow. To assess the benefit of the storage integration, the MILP optimization is therefore run without the storage under the same basic assumptions and the results are compared. The benefit of the storage implementation as described sums up to some 100k € in 2014. In the end this benefit has to be offset against investment costs, to clarify whether the storage is feasible for the plant.

It was found, that due to the rather long charging periods, the storage benefit can be significantly improved if the spot market prices are considered to be known for 36 (15 % improvement) or even 48 (30 % improvement) hours. The result is highly sensitive to the natural gas price. An increase of the price by 10 % doubles the benefit from the storage to over one Mio. €/year.

![Figure 11: Dispatch scheme for the plant with storage in a weak in January 2014. For high electricity prices the plant is operated in normal mode (blue spheres) generating as much power as possible, at medium prices, the storage is charged (green diamonds) and at very low prices the plant is shut down (orange squares) if the storage load is sufficient to supply the paper mill with heat.](image)

## 5. Conclusion and outlook

In this paper, the integration of a thermochemical storage in a co-generation combined cycle power plant providing heat and power for a paper mill is investigated. The target is to achieve a power controlled operation scheme for the plant that is presently operated heat controlled.

A process simulation model of the plant and the storage is set up using EBSILON Professional and from the results, a MILP-model of the plant is derived and an optimization of the dispatch scheme of the plant is performed.

It is found that a magnesia oxide/hydroxide storage is suitable for the desired temperature level and using state of the art heat transfer systems it can be integrated into the plant with a high roundtrip system efficiency.
Compared to a plant without storage, that was simulated applying the same conditions, the storage would generate an additional revenue of some 100k € in 2014. The economic considerations are still ongoing. An important next step is to estimate investment costs for the storage and calculate return on investment rates.

In the MILP-model it was assumed, that the complete electricity generation is sold on the spot market. In reality, electricity is consumed directly by the paper mill. This has the advantage that the paper mill saves taxes and transfer tolls. Furthermore, the German government is giving subsidies for electricity from co-generation. If the electricity generation of the plant is reduced to achieve more flexibility as presented in this paper, the amount of subsidies decreases and the paid taxes increase. This makes an operation as presented in this paper rather unfeasible at present legal conditions. Irrespective of the current market situation, thermochemical storage can be considered a powerful option when it comes to flexibilization of co-generation plants. Future development must show if the storage itself can be developed in the way necessary to make a large scale operation possible and given that, if the need for flexible operation outbalances the legal and economic drawbacks given at present day.

**Acknowledgements**

This research is part of the project “Thermochemischer Energiespeicher für thermische Kraftwerke und industrielle Wärme” and is funded by the German Federal Ministry of Economic Affairs and Energy (BMWi) under the funding code 03ET7025 according to a decision of the German Federal Parliament. The authors would like to thank Uniper Technologies GmbH and E.ON Energy Projects GmbH for providing necessary information and assisting the research.

**Nomenclature**

- **a, b, c, d**: Factors
- **h**: Specific enthalpy, kJ/kg
- **H**: Enthalpy kJ/kmol
- **m**: Mass flow rate, kg/s
- **on**: Binary signal
- **p**: Pressure, bar
- **P**: Power, MW
- **Q**: Heat flow, MW
- **start**: Binary marker
- **t**: Time, s
- **T**: Temperature, °C

**Greek symbols**

- **η**: Efficiency

**Subscripts and superscripts**

- **chem**: chemical
- **CU**: Combustion unit
- **ECT**: Extraction condensation turbine
- **el**: Electric
- **GT**: Gas turbine
- **in**: Inlet
- **out**: Outlet
- **PM**: Paper mill
Supplementary firing

Chemical symbols
Ca  Calcium
Mg  Magnesium
O   Oxygen
H   Hydrogen

Abbreviations
CC  Combined Cycle
HPT High pressure turbine
HRSG Heat recovery steam generator
LPT  Low pressure turbine
MILP Mixed integer linear programming
REA  Renewable-Energy-Act (Germany)

References


