Relevance and chances for industrial on-site generation of electricity for high market shares of renewable energies

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Abstract:

The present situation of German electricity market is characterized by many unknowns regarding future security of supply, grid stability and flexibility. In 2030, renewables energies are expected to account for 50-65% of Germany's electricity supply [1]. Such increase in highly volatile production rates will presumably be accompanied by unpredictable electricity prices in the liberalized electricity market, if no countermeasures are taken.

In this regard, industrial generation of electricity for self-consumption represents a useful mean to integrate higher proportions of conventional electricity producers into the market. Hence, the potential of a market participation of on-site generating industrial power plants in Germany's day-ahead market is investigated regardless of present-day market regulations, levies, network charges and fees. The paper aims on evaluating the potential changes in overall production costs and CO_2-emissions, as some industrial plants are expected to purchase their electricity at market prices while others sell additionally available capacity.

The presented assessment first emphasises the relevance of industrial on-site generation by gathering data concerning all relevant German industrial power plants. The role of combined heat and power systems is examined in particular due to high efficiency ratings. Sorting all industrial electricity production by branches and determining their marginal costs of production yields the merit order of industrial on-site generation. When integrating all self-generating industries in the day-ahead market for the entire year 2017, average market prices are increasing accompanied by an increased volume of traded electricity. As competition grows and cost-efficient suppliers are favored, average variable electricity production costs of the overall system are reduced. Still, CO_2-emissions rise in such an integrated system, as alternative means to provide industrial process heat must be operated.

The study's findings are discussed with regard to potential benefits and drawbacks of the proposed market integration. Energy demanding entities such as private households and especially large-scale industries are affected from increased market prices. Yet, reduced variable electricity production costs are favorable when aiming for an integrated system of maximum efficiency, even though emissions would rise. Conclusions are therefore drawn considering different viewpoints and necessary changes in a regulatory sense. Methodology and results in this paper were compiled within the project eXtremOS, supported by the Federal Ministry for Economic Affairs and Energy of Germany (funding id: 03ET4062).

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Keywords: electricity costs, day-ahead market, integration, bidding process, merit order, on-site generation, industry, IEWT 2019

1 Motivation and objective

At present, a major concern in the context of changing regulations and social developments is the volatility and potential lack of flexibility of Europe's liberalized electricity markets. Rapid developments concerning Germany's electricity market and its regulations during the past decade highlight the difficulty of future predictions in this regard. A key reason for increasing fluctuations of electricity prices is the ever growing ratio of renewable energies. In the case of Germany, the government's objective is to expand this ratio up to 65 % of renewables in the market by 2030 [1]. Due to the German Renewable Energy Sources Act (EEG) renewable energy is preferentially fed into the grid where the EEG surcharge on electricity consumers guarantees sufficient revenue for renewable plant operators. For some days of summer, nearly the entire electricity consumption is supplied by renewable energies. Thus, wholesale market prices increasingly drop below 0 €/MWh during these days.

The inconstancy of circumstances in the market evokes the need to rethink prevailing structures and consider new approaches such as the presented investigation regarding on-site generation of electricity of industrial power plants (IPPs). In this context, on-site generation of electricity implies a situation where electricity is generated by a producer whose main interest lies in an industrial product other than energy. Depending on its priority, the IPP might either operate on-site sufficient, purchase electricity at the energy market in case of shortages or sell a potential surplus at the market [2].

Producing one's own electricity is considered a cost-effective, secure mean to operate the industrial site [3]. Independency from market fluctuations and security of supply often limits the source of energy for large-scale industries. For self-generating IPPs, renewable power plants lose their incentive as a high level of controllability and reliability is desired. Especially in the case of constant electricity demand, other types of power plants such as gas and steam power plants are favorable. For combined heat and power (CHP) operation, the generation of electricity is accompanied by heat production, which in many installations is the controlling production factor. In other cases, furnace gases or other waste products from the production process are used for energy generation, as the alternative of disposing the waste at high costs is nonsensical from an economic perspective [2].

Since several factors motivate the on-site generation of electricity in industry, financial incentives are not always the main drive. In many cases, IPPs are operated throughout the year regardless of the present electricity price, which is counterintuitive with regard to the exceptionally low prices mostly during summer. The explanation of this mode of operation lies in the considerably high amount of levies, network charges and fees that must be paid on top of the market price. As a consequence, it becomes economically beneficial to run one's power plant even if the power production is generally more expansive than electricity market prices. Hence, the electricity market price does not necessarily represent the cost minimum of the entire electricity production as IPPs are not included in the market pricing process. Minimizing CO_2-emissions is also not guaranteed, since IPPs are mostly operated with fossil fuels. While the expansion of renewable continues, IPPs entail the danger of impeding the overall reduction of costs and CO_2-emissions, if operated in the same manner as today. For this reason, changes in regulations and operational mode concerning the on-site generation of IPPs might become inevitable.

In this paper, an approach is presented to integrate self-generating IPPs in Germany into the electricity market. The IPPs would thereby engage in the price formation process for both selling and buying purposes. Possible options of operating an IPP will be discussed within the framework of a general electricity system covering both electricity producers and consumers. Here, a distinction must be made between a holistic system perspective and a consumer perspective when discussing the economically most viable options. Taking the holistic system perspective, the system with the lowest averaged variable electricity costs represents the most viable option. From the consumer perspective, the economically most favorable option is the system of minimum market prices. Thus, considering both perspectives, the usage of IPPs can be divided into three possible scenarios:

- **First scenario**: Integration of IPPs causes a rise of both market prices and averaged variable electricity costs; unfavorable from both consumer and holistic system perspective
- **Second scenario**: Integration of IPPs causes a rise of market prices but a reduction of averaged variable electricity costs; unfavorable from consumer perspective but favorable from holistic system perspective.
- **Third scenario**: Integration of IPPs causes a reduction of both market prices and averaged variable electricity costs; favorable from both consumer and holistic system perspective

Scenario 1 represents a generally positive outcome, whereas scenario 3 would inevitably be rejected. Scenario 2 is ambivalent and its approval depends on the dominant perspective.

The investigation aims on clarifying which of the three scenarios prevails when integrating self-generating IPPs covering the timeframe of one year. Resulting consequences in terms of market prices, variable system costs and CO_2-emissions are outlined. Based on the outcome, a substantiated recommendation regarding future IPP operation can be articulated.

2 Methodological approach

The procedure to evaluate the possible market integration of industrial on-site generation comprises three basic steps: (1) Assessing the current situation including the identification and categorization of all relevant IPPs; (2) Developing of new merit order including all self-generating IPPs; (3) Modelling market integration through updated bidding curves resulting in new market prices. This three-step methodology is described in more detail in the following.

2.1 Assessment of the status quo

The current state of Germany's electricity system is examined to fully comprehend the market pricing process and operation of IPPs. To begin with, the scope of the assessed system should be clarified. Several different systems of electricity production are of importance. First, electricity can be traded through direct contracts from producer to consumer without any intermediary thereby simplifying the process. Second, long-term supply contracts are common practice for large-scale demand to limit risks and ensure supply security. Third, occurring discrepancies between supply and demand, which cannot be anticipated, are balanced through day-ahead markets. Here, electricity is traded to be supplied at each hour of the following day. Fourth, if supply and demand remain unbalanced during the actual day of demand, the intraday market allows to compensate for this deviations in electricity [4]. Fifth, IPPs are not participating in any electricity trading and instead utilizing self-generating electricity directly.

For the present study, IPPs should be integrated into the liberalized day-ahead electricity market. The applied trading mechanisms in the day-ahead market are mainly determined by marginal production costs thereby favoring cost-efficient producers. Thus, integrating IPPs should ideally minimize marginal electricity production costs in a free market framework. The above-mentioned various other market situations remain untouched so that henceforth only day-ahead market processes are assessed.

2.1.1 The present pricing process for day ahead market and industry

When investigating the status quo within the mentioned scope of day-ahead market and IPP on-site generation, it is best to interpret the situation as two separate production systems (illustrated on the left of figure 1). System 1 comprises the electricity market, where power producers supply demanded electricity to consumers (partly including the industrial sector) at market prices. The hourly pricing process at the day-ahead market is conducted through bids for both supply and demand. Consumers are stating their demand and the price they are willing to pay per unit of electricity. Their bids are sorted in descending order thereby cumulating the needed amount of electricity. The graph on the right of figure 1 displays an exemplary resulting demand curve in green. Power producers are offering their available capacities at appropriate prices, which ideally equal their marginal production costs. The supply bids are then sorted in ascending order starting for cumulated electricity supply. In the case of renewable energies covered by the EEG-apportionment, the bids are located at the lower part of the order regardless of their marginal costs thereby ensuring their usage. The resulting supply curve is illustrated in orange in the right graph of figure 1.

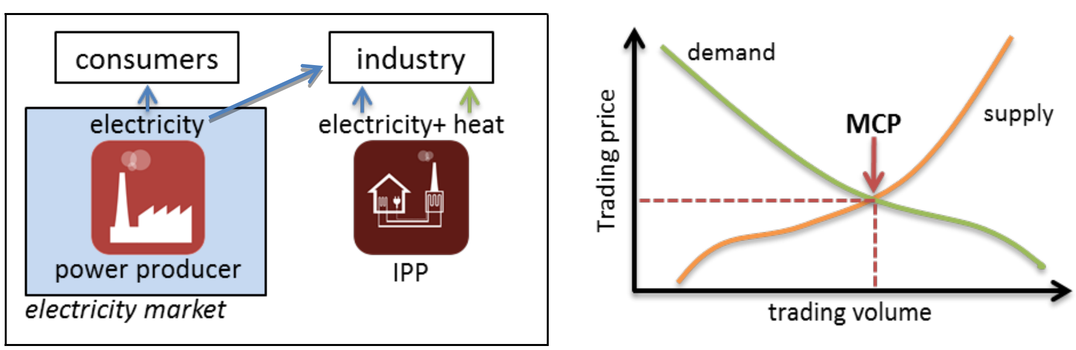

Figure 1: Left: Status quo of electricity system, electricity is produced in two separate sub-systems. Right: Pricing process of the day-ahead market.

As soon as the bidding process is completed for the hour, the intersection between the two curves is determined. The corresponding price of the intersection is called the market clearing price (MCP), which is the binding price per unit of electricity for every market participant. The MCP is equivalent to the last successful supply bid, where the profit margin is considerably lower than for bids further left on the supply curve. Vice versa, consumers submitting higher bids than the MCP on the demand side will eventually pay less than their original offer. Thus, it is risky for both producers and consumers to bid more respectively less than their marginal value of minimum profit, as they might not get the acceptance of bid. The pricing process in the day-ahead market therefore ensures cost-effectiveness [4]. The traded volume at MCP is the amount of sold electricity in this precise hour.

System 2 involves self-generating IPPs, which produce their own electricity. No trading mechanism is applied here. Depending on the specific industry and requirements, the owning company choses to operate the plant with little or no regard to the MCP.

2.1.2 Identification and classification of relevant IPPs

To gain an overview regarding the self-generating IPPs in Germany, data of industrial electricity production is acquired from different sources:

- The German Federal Network Agency (BNetz-A) provides a list of all German electricity power plants [5].
- The FfE internal database covers most IPPs in Germany including data such as capacity, energy source, system type and spot market prices on an hourly base.
- The European network of transmission system operators for electricity (ENTSO-E) provides electricity production data on an hourly base for most European power plants of 100MW rated capacity and more provided by transmission system operators (TSOs), power exchangers and qualified third parties [6].

Matching the first two data sources results in a list of self-generating IPPs. As the hourly electricity production is essential for market integration, the ENTSO-E data is paired with hourly spot market prices as well as supplementary IPP information. Unusual operating patterns such as constant electricity production or production curves reacting inversely to market prices represent typical IPP behavior. Figure 2 displays a characteristic IPP production curve with regard to market prices, where no relation between market price and production rate exists. For instance, the expected drop in production due to financial losses when selling electricity at particularly low prices fails to appear. Peaks in production are not connected to especially high market prices or vice versa. Hence, the displayed plant must be an IPP potentially producing electricity as a by-product at a CHP operation.

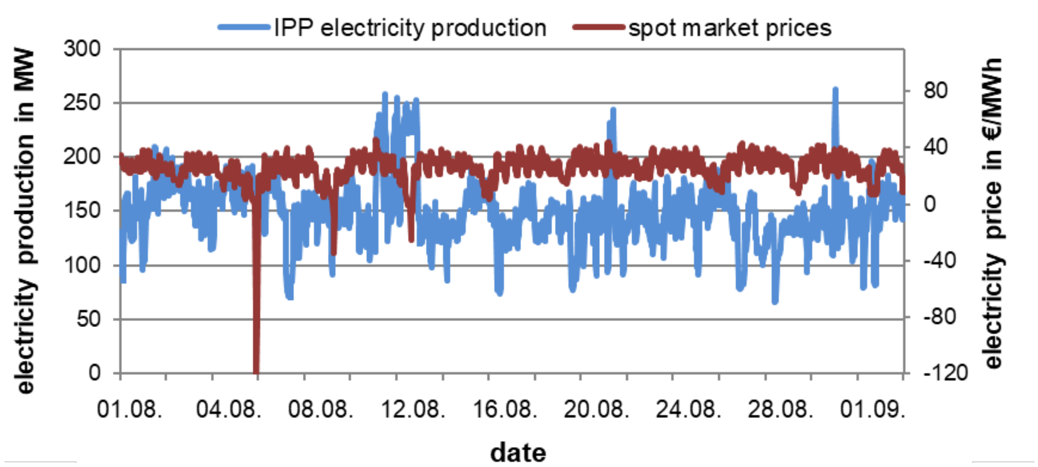

Figure 2: Characteristic operating pattern of an IPP in combination with spot market prices for 2017. No direct relation regarding price and production is evident.

Data regarding the annual net electricity of IPPs available at the German Federal Statistical Office (Destatis) exceeds the annual sum of IPP electricity production of the formerly gathered data, which implies that the obtained list of relevant IPPs does not cover each IPP in Germany. Thus, a scaling approach is necessary. As the Destatis data is categorized by industry branches [7], the scaling is conducted based on the most important branches in self-generating industries. To do so, all relevant IPPs are first sorted by industry branch, installed capacity, energy source and mode of operation (CHP, self-sufficient and/or grid connection). The distinction between conventional power plants and CHP plants is essential, as the cogeneration of heat and electricity largely determines the power output and electricity generation costs. Specifying the ratio of electrical on-site consumption to grid feed allows accounting for the relevant amount of on-site consumed electricity by IPPs.

Once the IPPs are categorized by branches, their summed installed capacity and hourly electricity production is scaled so that the resulting annual amount of electricity per energy carrier matches the electricity data provided by Destatis. For each branch a characteristic production curve is developed by averaging the ENTSO-E data allocated to the particular branch. At the end of the scaling process, all relevant IPPs in Germany are comprised in a table sorted by industry branches, where annual electricity production, rated power output and hourly production curves are on file.

2.2 Development of merit orders for industrial on-site generation

The next assessment step involves the calculation of marginal electricity production costs for each identified IPP. The marginal production costs for all relevant industry branches are then determined by averaging the costs of IPPs for each branch. In the context of this study, marginal costs display the overall specific costs for an energy producer to bring the electricity to the market. If market prices exceed marginal costs, no electricity is produced as no financial incentive exists. The marginal costs therefore determine whether a power plant participating in the market should generate electricity or not.

Apart from data regarding electricity generation and electric efficiency, which is derived from [8], information regarding the nominal heat production in case of a CHP plant is acquired from the FfE database. In addition, specific costs concerning energy source, CO_2 emissions and produced heat are based on [9], where both type of power plant and energy source determine the employed values.

Utilizing the gathered data, the marginal costs per unit of produced electric energy are calculated via a variation of the following equation:

$$marginal\ costs = \frac{1}{\eta_{el}} \cdot \left(c_{energy\ source} + c_{CO_2} \cdot e_{CO_2}\right) - \frac{\dot{Q}_{heat,rated}}{P_{el,rated}} \cdot c_{heat} - c_{opp}$$

where η_{el} is the electric efficiency, c are the specific costs corresponding to each subscript, e_{CO_2} are the specific CO_2 emissions for each energy source , $\dot{Q}_{heat,rated}$ is the rated heat production and $P_{el,rated}$ is the rated electricity production.

A strict distinction is made between demand and supply perspective. In the case of participating in the buying process (demand side), CHP operation and source of energy are decisive factors. If heat is cogenerated, the IPP operator would only buy electricity at a low price which allows for an additional purchase of heat. Thus, the hypothetical costs to receive thermal energy from another source reduce the marginal costs. If no heat is generated, the second part of the equation covering heat production is neglected. If the industrial plant uses waste products, renewable energy sources or furnace gases, specific energy source costs are reduced to zero as the energy source is available for free. Additionally, if the energy source causes any kind of opportunity costs, as is the case for furnace gases, which have to be disposed if not used for electricity production, these are added through the third part of the equation.

In the case that the IPP would participate in the bidding process for selling electricity (supply side), it might produce additional electricity on top of its self-supply if possible. Even in the case of a CHP operation, no heat production is considered as the additional heat would not be sold. For such additional electricity production, no waste products or furnace gases are used, as these are already employed to meet the demand. Thus, the marginal costs of supply comprise fuel costs and costs for CO_2 emitted into the atmosphere thereby neglecting the second and third part of the equation. As a result of these distinctions, two sets of marginal costs are determined for each IPP, which are identical only if the plant does not operate in CHP mode.

Once the averaged marginal production costs are allocated to the corresponding branch, the merit order for self-generating IPPs comprises two parts: (1) Marginal costs of demand representing the prices below which electricity would be bought; (2) Marginal costs of supply representing the prices above which electricity would be sold. As the ratio between actual power generation and additionally available generation capacity varies, a new merit order is developed for each hour of the year. These merit orders will then be used as a tool to integrate the IPPs into the market's pricing process.

2.3 Update of pricing process and MCPs

The inclusion of self-supplying IPPs into the German day-ahead market is modeled by modifying both supply and demand bids of the hourly pricing process (see section 2.1.1). As the market participants offer or buy electricity at marginal value, the curves of buying bits and the curve of selling bits can be seen as merit orders of marginal prices. Thus, the integration of IPPs is accomplished by employing the developed merit orders for industrial on-site generation. For each industry branch, the amount of electricity is sorted into the curves at the position of corresponding prices. The marginal costs of demand are thus integrated into the curve of buying bids, while the marginal costs of supply are integrated into the curve of selling bits. Since the market integration aims on solely displaying the potential effects on the pricing process without any claim on practicability, it is sufficient to neglect potentially occurring additional charges or levies.

The market integration results in changed bidding curves, which in turn alters the point of intersection, i.e. the MCP, for each bidding hour. To fully understand the possible events when integrating additional capacities to the cumulated bids four scenarios are displayed in figure 3, which illustrate occurring changes accompanying the simple integration of an exemplary IPP at different marginal costs:

- **A) First demand scenario**: Marginal costs of IPP are lower than market prices, so that on-site generation continues. The market price remains unchanged.

- **B) Second demand scenario**: Marginal costs of IPP exceed market prices, so that required electricity is purchased in the market and IPPs are not operated. The surplus in demand causes an increased market price.
- **C) First supply scenario**: Marginal costs for additional production capacities of IPP exceed market prices, so that no additional electricity is produced. The market price remains unchanged.
- **D) Second supply scenario**: Marginal costs for additional production capacities of IPP are higher than market prices, so that additional electricity is sold in the market. The surplus in supply causes a reduced market price.

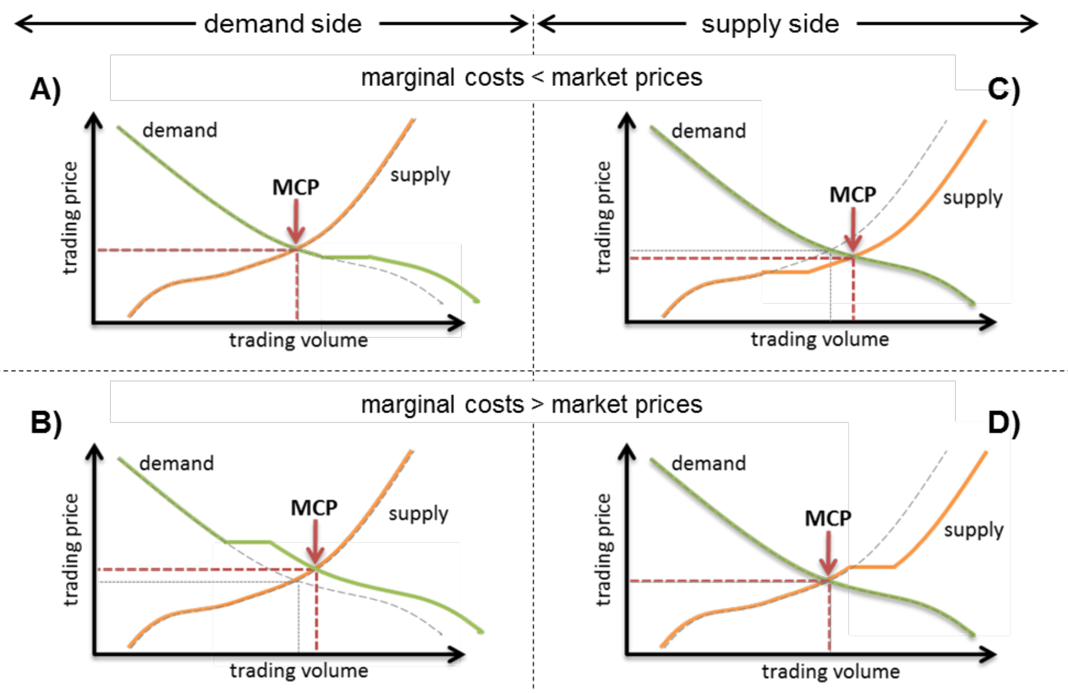

Figure 3: Effect of possible changes in bidding curves on market price and traded electricity volume

As demand and offer scenarios appear at the same time, the change in market prices depends on marginal costs for both demand and supply side. A high amount of demanded electricity integrated left to the previous MCP will favor an increased MCP, whereas a high amount of offered electricity integrated left to the old MCP will benefit a decreased MCP. After integrating each new bid of demand and supply for every industry branch, the updated MCPs are calculated for each hour of the year.

Finally, changes regarding the overall system including market and industry are investigated by comparing variable electricity production costs and CO_2-emissions of the new system to the previous situation (status quo). The difference in industrial variable costs is due to IPPs, which are now purchasing their electricity in the market while obtaining the desired process heat though an alternative heat-generating process (demand side). The difference in variable market costs is due to suppliers, which are producing now that the demand is increased (supply side). The total difference of variable production costs per unit of shifted electricity is determined via the following equation:

$$\Delta\, variable\, costs_{total} = \Delta\, variable\, costs_{industry} + \Delta\, variable\, costs_{market}$$

$$= \frac{\sum(c_{industry} \cdot \Delta W_{el,industry}) + \sum(c_{market} \cdot \Delta W_{el,market})}{\Delta W_{el,industry} + \Delta W_{el,market}}$$

where c are the variable production costs of each relevant electricity producer in the system and ΔW_{el} are the changes in electricity production. Data of industrial on-site generation regarding emissions and marginal costs is provided for each branch by the previously mentioned sources. For market developments, selling bits are considered to be identical to marginal production costs as a close approximation. In this sense, it is important to stress that a system perspective is taken. Potential charges or levies, which might be additionally imposed when participating in the market, become negligible as the objective is to investigate the attainable reduction of overall production costs of market integration.

To approximate differences in CO_2-emissions a similar approach is taken. For industrial on-site generation, emissions are reduced by the amount of IPPs, which stop their electricity production at the time. At the same instance, new CO_2-emissions arise from the alternative heat generation process in the case of a CHP system. In the market, CO_2-emissions increase by the amount of new market participants, which are partly IPPs selling additional electricity and partly other producers benefiting from rising MCPs. Emissions are calculated for each kind of energy source with regard to the plants efficiency. The alternative heat generation is based on emission data for conventional heating plants taking only the original energy source into account [10]. Due to such generalizations, results concerning CO_2-emissions can only be seen as a first estimate to show the effects and trends of market integration. Through the comparison of changes in market prices, variable production costs and CO_2-emissions the usefulness of a potential market integration of self-generating IPPs can be evaluated.

3 Results and discussion

In the following, results regarding the assessment of industrial on-site generation of electricity are presented for the year 2017, as it represents the most recent set of complete data available. The methodical approach explained in section 2 is conducted step by step, where particular emphasis is placed on quantifying benefits and drawbacks of the potential participation of IPPs in the German day-ahead market.

3.1 Assessing the status quo

To start with, utilizing data of the three mentioned sources of information (BNetz-A, FfE Database, ENTSO-E transparency platform) yields a list of 16 self-generating IPPs with hourly electric power production data available. Their installed electric capacity adds up to 2982 MW. In 2017, 15733 GWh of electric energy were produced, which implies high utilization rates and hours of full load throughout the year.

The 16 IPPs use five different primary energy sources, where the largest proportions in terms of generated electricity are due to furnace gases, a mixture of various gases including natural gas or natural gas only. Waste products and hard coal constitute the other important sources, which are deployed to a lesser extent. 15 out of the 16 IPPs are operating in CHP mode. In most cases, the produced heat is used to run industrial processes making the heat generation indispensable. Gas-powered CHP plants are the medium of choice whenever process heat is needed, as a fast response time is coupled with high efficiencies. In the day-ahead market, however, such CHP plants are operated only during periods of high market prices as fuel costs are generally high. Thus, CHP plants operated with gas constitute an excellent example of systems that are widely spread in industry because of the advantageous usage of waste gases, which would otherwise cause high disposal costs. Other IPP types such as conventional coal-fired power plants appear to be operated for reasons such as need for reliability of supply and exemption of levies and network charges.

The 16 IPPs identified through ENTSO-E data can be categorized in four industry branches. Taking the Destatis report of annual electricity production sorted by industry branches into account [7], it becomes evident that these four branches comprise most of the relevant branches in terms of electricity production. For remaining branches of importance, for which no hourly production data is obtained, average electricity production rates are used. Industry branches of lesser importance are partially allocated to similar branches or collected in an additional branch of residual electricity production. The procedure results in 6 industry branches with the individual IPPs data scaled so that the annually produced electricity matches the Destatis information. The outcome is presented in table 1.

Table 1: Resulting industrial on-site generation of electricity in 2017 sorted by relevant branches

Industry branch	Electricity production		Installed capacity	
Production and processing of fuels	1,804 GWh	3%	243 MW	3%
Paper and wood products	8,621 GWh	16%	1,200 MW	13%
Chemicals and synthetics	25,755 GWh	49%	4,342 MW	48%
Metal production	9,680 GWh	18%	2,155 MW	24%
Vehicle manufacturing	4,628 GWh	9%	789 MW	9%
Others	2,291 GWh	4%	412 MW	5%
Total	52,779 GWh	100%	9,141 MW	100%

The total self-generated electricity accounts for 9 % of the overall generated electricity in Germany in 2017, which underlines not only the general importance of this topic but also the potential savings in both economic and environmental regards. On average, 70 % of the IPPs operate in CHP mode, where the overall amount of generated heat is 2.3 times higher than the total electricity production in industry.

It is evident that the chemical industry including production of pharmaceutics and synthetics accounts for nearly half of the annual electricity on-site generation. This branch is especially reliant on on-site generation as the energy-consuming production process is mostly operated in shifts leading to a high number of full-load hours. An additionally high demand for process heat favors combined steam and gas CHP plants operated with natural gas or a mixture of gases with high overall efficiencies. Concerning the metal production industry, an extensive usage of furnace gases is noticeable. In that case, the utilization of flammable furnace gases arising during the production process as an energy sources ultimately reduces emissions and electricity costs. The production of paper and wood also represents an energy-intensive branch, where process heat is efficiently cogenerated in a similar manner as for the chemical industry. For the production of vehicles, CHP is only partly relevant. Decisive factors for on-site generation are reliability of supply and independence from market fluctuations. In the branch of fuel production and processing the utilization of waste products enables on-site generation to a certain degree. In addition, the electricity demand for this branch is on a generally constant level leading to a steady operation on high load for such IPPs.

The differences in operational mode and reasons for on-site generation show the importance of a distinction between each relevant branch. This distinction becomes crucial when assessing the averaged marginal costs of electricity production. The merit order of industrial on-site generation in figure 4 shows the high variability of marginal costs when distinguishing between branches, energy sources and between electricity production capacities which are in use and those which are available for additional production. The MCP at the exact time is included in the figure emphasizing that most of the available capacity marginal costs exceed market prices. It is evident that marginal costs for many branches during usual operations are relatively low. One reason for this observation is the high amount of must-run IPPs at the left side of the merit order. These are IPPs, which operate with renewables, furnace gases or waste products. Their marginal costs are that low so that such IPPs are not replaced during normal operation. A second reason for relatively low costs at the left graph are CHP systems, which reduce the marginal costs by the amount of opportunity costs for heat production. Especially for branches such as the chemicals industry, where a large percentage of self-generated electricity is produced by steam and gas CHP plants using natural gas, the determined marginal costs might justify self-sufficient power supply, as the MCP is not exceeded for the present case and supplementary fees are disregarded. The significant increase of marginal costs when considering additional usage of available generation capacity is mainly caused by the fact that no cogeneration of heat is accompanying this operation due to a lack of demand and no additional opportunity costs arise here.

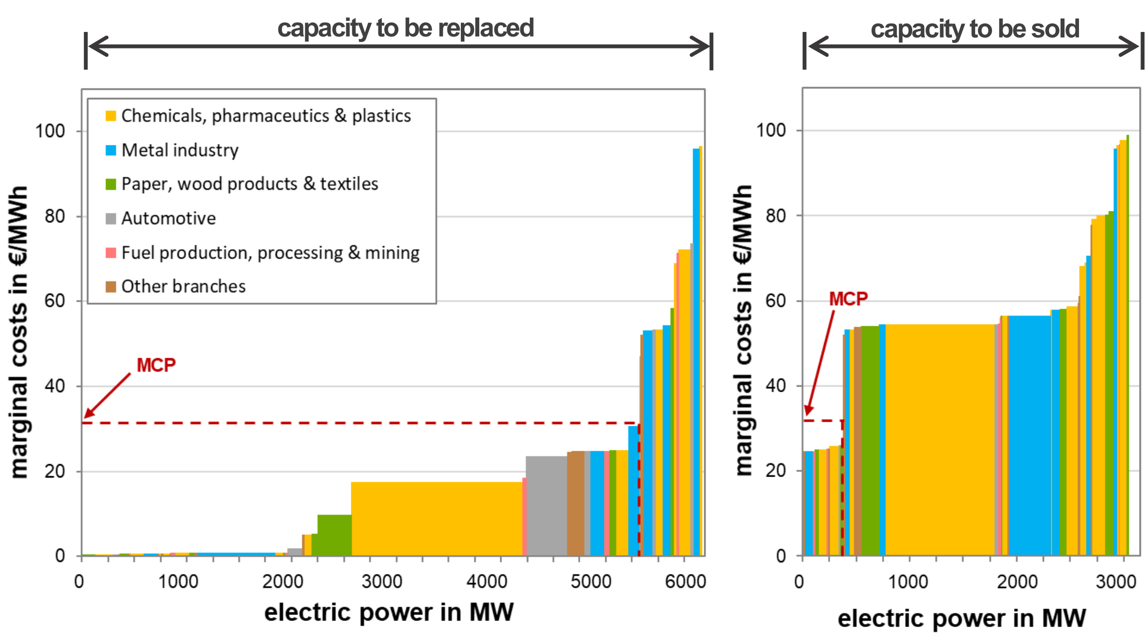

Figure 4: Merit order of industrial on-site generation including MCP for 10:00, April 10th 2017. For each branch, a proportion of the installed capacity is used for usual operation (left graph). The remaining capacity is available for additional electricity provision at higher marginal costs (right graph).

Some industries such as the metal production or the production of fuel operate IPPs, cover a large share of must run plants which operate whenever a furnace gas or waste product is produced to avoid potential disposal costs. Such IPPs comprise very low marginal costs thus ensuring this must-run behavior when participating in the market. Whenever additional electricity is produced by such must-run IPPs, their marginal costs rise to the usual level of the particular plant type. In the case of fuel production industries, those marginal costs reach high levels due to relatively inefficient plant types and high energy source costs. Thus, selling additional electricity seems unlikely in these cases. Yet, both merit order and MCP change for each point in time and no conclusions regarding the annual outcome can be drawn from the example presented here. For this reason, the merit order of industrial on-site generation is developed for the each hour of 2017 allowing for a comparison between marginal electricity production costs and MCPs.

3.2 Evaluating effects of market integration

The theoretical market participation of self-generating IPPs is modelled by integrating marginal costs for demand into the curve of buying bids and marginal costs for supply into the curve of selling bids. From an industry perspective, marginal costs of demand comprise all capacities, which are originally in usual operation, as these capacities could be substituted by buying electricity at a lower price. Marginal costs of supply cover the additionally available capacities, which can be activated to sell electricity if market prices exceed the corresponding marginal production costs.

3.2.1 Changes at an exemplary point in time

As an example, the updated pricing process is first investigated for 10:00 on April 10th 2017. Figure 4 is generated for the same instance. Figure 5 shows the resulting differences between original bidding curves and the updated version, where industrial on-site generation is included. When examining the zoomed view on the right, is becomes clear that the deviation regarding the demand curves is much higher than the deviation of the supply curves.

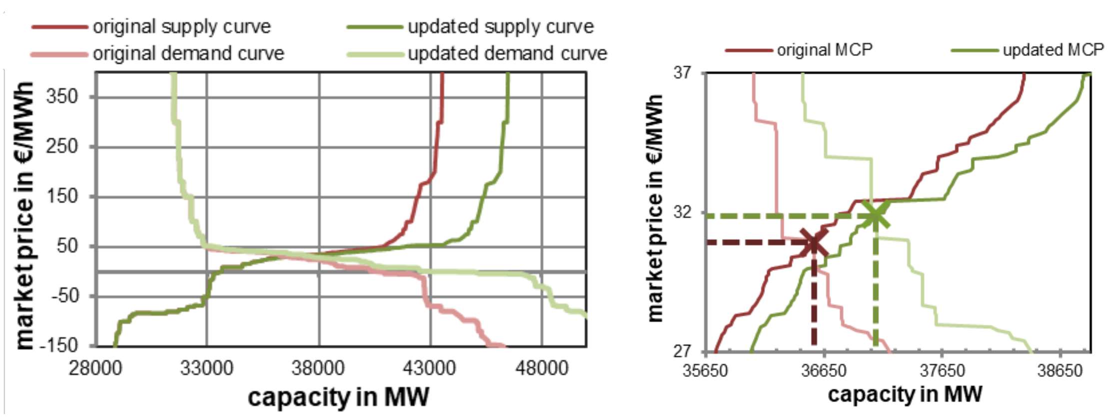

Figure 5: Chances in updated bidding curves (left) and magnified view of intersection between both curves highlighting the different MCPs (right) for 10:00, April 10th 2017.

Thus, many IPPs are purchasing their electricity in the market for the integrated scenario, whereas the additionally offered capacities are hardly sold due to higher marginal costs for additionally produced electricity. 1210 MW of industrial on-site generation are exchanged against other production types. Especially the marginal costs for on-site generation of the chemicals and synthetics production and of the metal industry are replaced (see merit order, left, figure 4). The other IPPs continue their usual operation. 350 MW of industrial electricity are additionally sold as a surplus to ongoing electricity generation. The resulting increase of 3.3 % in MCP is the expected outcome of an increased demand at the market, where some IPPs are replaced by lower-priced producers. However, the increase appears to be smaller than expected.

As new producers are selling electricity while others stop their production in the modified system, a new situation concerning the overall system perspective is presented leading to changing variable electricity production costs. The economically negative impact of additional producer supplying the surplus of electricity demand and the alternative heat generation for substituted CHP IPPs is thereby surpassed by the replacement of expensive self-generating IPPs as displayed in table 2. As a consequence, variable production costs are reduced for the integrated system leading to a saving of 24,710 € from a holistic system perspective for this hour. Note that for alternative heat production changes in electricity production are zero even though they are directly connected to replaced IPPs. The remaining difference between replaced and additional electricity production is due to displaced consumers, which were formerly able to purchase electricity at lower market prices.

Table 2: Differences in variable production costs and CO_2-emissions for 10:00, April 10th 2017

Market changes	**variable production costs**		**CO_2-emissions**
	ΔW_{el}	ΔC_{var}	Δm_{CO_2}
Replaced self-generating IPPs	1210 MWh	- 84,432 €	- 658 t_{Co2}
Alternative heat generation		+ 20,894 €	+ 255 t_{Co2}
Additionally activated IPP capacities	350 MWh	+ 8,888 €	+ 261 t_{Co2}
Additional market participants apart from IPPs	860 MWh	+ 29,940 €	+ 459 t_{Co2}
Total		- 24,710 €	+ 317 t_{Co2}

Concerning CO_2-emissions, the results in table 2 indicate that replacing the self-generating IPPs would increase CO_2-emissions. A plus of 317 tons of CO_2 during this hour displays the negative impact of market integration from a holistic system perspective, where the alternative generation of heats accounts for a substantial share of additional emissions. The financial drawback for increased emissions remains relatively low, so that the overall financial savings of variable costs (ΔC_{var}), which include emission costs, are not affected in a significant way at this moment.

3.2.2 Changes over the course of one year

Conducting the process of market integration by modifying every bidding curve for each hour of the year yields new MCPs for 2017. These MCPs alongside with the resulting changes in electricity generation are best discussed by comparing averaged values between the status quo and the updated system.

As examined in the previous section, an increase in market prices is expected whenever marginal costs of on-site generation exceed MCPs due to an increase in demand. The lower the MCP during the year, the more on-site generating IPPs are replaced by less expensive electricity producers. For very high price levels, however, market prices decrease as most IPPs continue their on-site generation of electricity, while replacing more expensive producers in the marked by selling additional capacities. Hence, periods of very high prices might counterbalance the rise of MCPs over the course of a year.

To illustrate the results over an appropriate time period, two characteristic months are presented in figure 6. Both months highlight the dependency of resulting price changes with regard to the original market prices:

- January 2017: The coldest month of the year is characterized by periods of high MCPs. During periods of low to medium prices, updated MCPs exceed original prices. As such low to medium prices prevail, the average MCP rises by 1.7 € (3.1 %)
- August 2017: The warmest month of the year is related to generally low MCPs involving significant differences between the status quo and the updated system. Updated MCPs are increased throughout the month resulting in an average rise of 2.3 € (7.4 %)

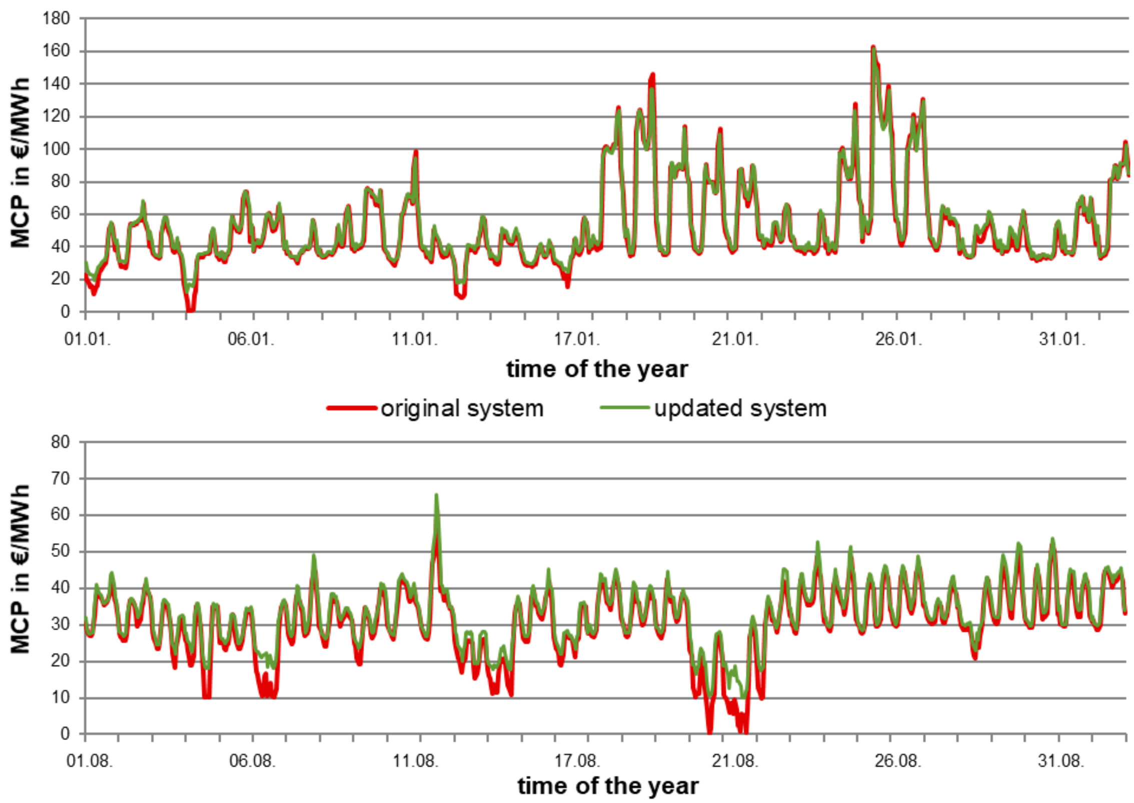

Figure 6: Changing market prices for January (top) and August (bottom) 2017.

In 2017, the effect of increasing MCPs during periods of low prices outbalances the effect of decreasing MCPs, where prices rise for 7900 hours of the year, drop for 800 hours of the year and remain unchanged for only 60 hours. As table 3 entails, a considerable increased averaged MCP is the result. The electricity capacity traded at the market is additionally enlarged throughout the year. Thus, through the integration of IPPs in the day-ahead market 11 % of the total industrial on-site generation is substituted by other means of electricity production thereby inducing 6 % higher market prices.

For some IPPs, marginal costs are exceeded most of the time. This holds true for the chemicals and synthetics industry as well as for the metal industry. Other IPPs continue their self-sufficient power provision throughout the year. Such IPPs sell additional capacities to a high extend thereby profiting from their market participation. Nevertheless, all demanding market participants are affected by the rise in MCPs, which makes the presented approach disadvantageous from an electricity customer perspective.

Table 3: Resulting changes in MCP and traded capacity on average for 2017

Market changes	**Original system**		**Updated system**	
	MCP	Traded capacity	MCP	Traded capacity
Average value	34.74 €/MWh	26,604 MW	36.92 €/MWh	27,042 MW
Difference to original value			**+ 2.18 €/MWh**	+ 438 MW
			+ 6.3 %	+ 1.6 %

From a holistic system perspective, however, the decisive evaluation criterion is the change in variable production costs over the year. Table 4 shows the resulting reduction of variable costs including emission costs. In case of a lower MCP occurring at high price levels, electric on-site generation continues as it would be too expensive to buy electricity in the market. Yet, available capacities of operating IPPs are sold at the market, when their marginal costs fall below market prices. As these marginal production costs are lower than the average variable costs of additional producers, the total costs for production decrease. For high prices at low to medium price levels, variable costs are reduced by the amount of previously self-generating IPPs which are now buying electricity at MCP. Despite of the additional need for heat generation and new electricity producers replacing the IPPs, variable electricity production costs are reduced by a total of 104 million euros in 2017, where 3 TWh of electricity are additionally sold at the day-ahead market and 6 TWh of industrial on-site generation are substituted by more efficient electricity producers. Concerning the differences in variable costs of shifted electricity, the huge proportion of replaced industrial on-site generation is the main reason for the achieved price reduction. Thus, taking the view of a holistic system manager, the proposed market integration is financially advantageous.

Concerning the changes in CO_2-emissions displayed in table 4, an unfavorable impact in environmental terms is obtained. The share of annually replaced IPPs is outbalanced by the share of additionally operating market participants in terms of CO_2-emissions. Additionally, the need for an alternative heat production causes even more emissions, since highly efficient CHP systems are replaced by two separate systems for electricity and heat production. As a consequence, 1.8 megatons of CO_2 are additionally emitted into the atmosphere making the approach under the given circumstances environmentally disadvantageous.

Both the amount of reduced variable costs and the amount of increased CO_2-emissions are relatively low with regard to the overall industrial sector. Hence, the findings can only be seen as a trend, which is subject to external factors and might alter for different assumptions and circumstances. The overall financial and environmental benefit of the proposed market integration highly depends on the prices for CO_2-certificates, which are relatively low for the presented case of 2017. Thus, the financial drawbacks regarding the increase in CO_2 is still outweighed by the overall savings of variable costs.

Table 4: Total differences in variable production costs and CO_2-emissions for 2017

Market changes	variable production costs		CO_2-emissions
	ΔW_{el}	Δc_{var}	Δm_{CO_2}
Replaced self-generating IPPs	6,115 GWh	- 398 Mio. €	-3,702 kt_{Co2}
Alternative heat generation		+ 75 Mio. €	+1,066 kt_{Co2}
Additionally activated IPP capacities	3,100 GWh	+ 108 Mio. €	+2,415 kt_{Co2}
Additional market participants apart from IPPs	3,015 GWh	+ 111 Mio. €	+2,048 kt_{Co2}
Total		- 104 Mio. €	+1,827 kt_{Co2}

4 Conclusion and Outlook

The presented assessment underlines the relevance of industrial on-site generation. 9 % of the total electricity production in Germany is due to IPPs, which produce at high marginal costs and on a fossil fuel base in most cases. The usage of CHP systems is particularly effective in industry due to the high utilization rate of process heat. Allowing these self-generating industries to participate in the day-ahead market would increase competition and eliminate inefficient electricity production especially during hours of high shares of renewable energies sold at low prices. Such expected high shares of renewable energies bear the risk of causing unpredictable fluctuations in the grid over the next decades, where the significant amount of conventional electricity production capacity of IPPs displays a useful resource to counterbalance instabilities.

The conduced study reveals that a market integration of industrial on-site generation generally causes an increase of market prices by 6.3 % accompanied by a 1.6 % increase of traded electricity. Throughout the year many industries exchange their self-generated electricity against market participation leading to a 11 % reduction of self-generated electricity. Cost-efficient IPPs continue their on-site generation but sell additionally available capacity at market prices. The variable electricity production costs of the overall system comprising market producers and industrial on-site generation are thereby reduced resulting in significant financial savings of 104 million euros in 2017.

Out of the three possible outcomes mentioned in section 1, the second scenario is identified to occur, where the updated market situation is beneficial from a holistic perspective and unfavorable from a customer perspective. An explicit statement regarding the usability of the presented approach would be impractical, as it depends on the prevailing perspective.

The negative impact of increasing electricity market prices for the end customer are affecting private households and small business only to some extent, as rising market prices decrease the EEG apportionment costs, which in turn reduces the final consumer price. However, energy-intensive large-scale industries are often granted a reduction or exemption of EEG apportionment costs. If market prices begin to rise, the positive effect of decreased EEG apportionment costs is diminished due to the small proportion those costs represent of the overall electricity costs. As a consequence, such companies would especially suffer from the proposed market integration. For this reason, it is highly important to consider an effective incentive for energy-intensive industries when proposing market participation. Arrangements such as exemption clauses for the market participation of self-generating industries, where electricity production costs exceed a fixed price limit, could be appropriate tools when rethinking the role of industrial on-site generation in the future electricity market.

Regarding the environmental impact of the proposed market integration, generally rising CO_2-emissions are detected. One reason is the replacement of IPPs mainly operating with natural gas and oil by coal-fired power plants in the market. Additionally, industrial CHP systems are replaced by two separate systems of electricity production through market participants and alternative heat generation. CHP systems therefore play a crucial role in industrial on-site generation due to their high overall efficiency and the great amount of demanded process heat for industrial purposes.

2017 displays a year of relatively low CO_2-certificate prices of 6 €/t. Higher CO_2-certificate prices would reduce the amount of replaced industrial CHP systems and gas-operated IPPs, as their marginal production costs would increase to a lesser extent than for less efficient systems using fossil fuels. Hence, for future scenarios of increased CO_2-certificate prices a relatively small share of IPPs is expected to be replaced by other electricity providers, while most of the CHP systems remain self-generating. The rise in market prices would thus be reduced as would the rise of CO_2-emissions, while overall variable production costs could still be minimized through market integration. It is noteworthy that such considerations are always speculative to some extent, which is why the results presented here merely display a tendency based on the situation in 2017. For future years, updated calculations are important to verify or refute this tendency.

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