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Report

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1st Report Future Power Market Workshop 2014, Florence, 25.4.2014

Suggested Citation: Neuhoff, Karsten; Ruester, Sophia; Schwenen, Sebastian (2014) : Gas and Electricity Market Design for a Flexible Operation of Gas-fired Power Plants, 1st Report Future Power Market Workshop 2014, Florence, 25.4.2014, Deutsches Institut für Wirtschaftsforschung, Berlin

This Version is available at:

<http://hdl.handle.net/10419/102758>

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Gas and Electricity Market Design for a Flexible Operation of Gas-fired Power Plants

Summary Report on Future Power Markets Workshop, held in Florence on 25 April 2014

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SUMMARY

Gas-fired power plants constitute a direct and important link between the gas and the electricity sectors and thus between the Target Models for electricity and gas. As the need for a flexible operation of gas-fired power plants will increase in tomorrow's low-carbon power markets, so also will the challenges for market design of both sectors in allowing for flexible trading arrangements. For the electricity markets, options to advance intraday and balancing market design are currently discussed, such as complex bids, the frequency of intraday and balancing market clearing, and the joint optimization of energy and reserve markets. For the gas market, concrete options for design advances are yet to be explored. The success – and the flaws – of the implementation of the new EC Network Codes for gas will provide new food for debates. Last, the interaction between gas and electricity TSOs in balancing the heavily interlinked short-term electricity and gas markets poses a need for (more) coordination between the different types of TSOs.

Challenges for flexible gas-fired power plants with today's gas and electricity market design

Power systems with high shares of intermittent RES require flexible mid-merit and peak technologies, as residual load becomes more volatile, and load gradients increase. Together with an increasing demand participation and electrification of other sectors, stochastic demand and supply face challenges in being matched, and thus the value of flexibility increases. Flexibility in general can be understood as the technical possibility and economic viability for market participants to balance own portfolios as well as for TSOs to balance the system as a whole at every moment in time.

There are technical constraints from the side of potential flexibility providers and costs to flexibility, such as ramping and start-up costs. Thus, the benefits of flexibility come at a cost for market participants, and the immediate question arises, how market design allows those costs to be properly remunerated. For gas-fired power plants that rely on flexible gas input for a flexible power output, this question refers to both electricity as well as gas market arrangements.

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The initial reasons that introduced the need for flexibility, decarbonization goals and RES integration add another side to the debate: flexible gas-fired power plants generally emit smaller amounts of CO₂ emissions than coal-fired power plants.

In summary, from a *power system engineering perspective*, gas-fired units are valuable to TSOs due to their favorable characteristics in terms of flexible operation (very fast start-up, high ramping rates, etc.). From an *environmental perspective*, gas as a fuel is favored by policymakers as compared to coal due to its substantially lower specific CO₂ emissions. *Companies*, however, currently favor coal for reasons described above. Assuming commodity prices for coal remaining relatively low, an ETS price to a multiple of today's level would be needed to facilitate a fuel shift again from coal to gas. With expectations for such increases in the short-term being low, and significant surplus generation capacity across most of the European countries, appetite for any long-term investment in flexible gas-fired generation is limited. This illustrates that technical flexibility does not necessarily translate into economic viability of flexibility.

On top of complex market arrangements and interactions, a political dimension is inherent to gas markets, too. In 2012, imports into the EU accounted for about 85% of total EU gas consumption. Foreign, non-EU producers, such as Gazprom, are often held in majority shares by States rather than private investors, and in addition form an oligopolistic market structure. Investments into liquefied natural gas (LNG) import capacities could substantially increase diversity of supply sources as well as supply routes and contribute to energy security, and with increasing shares of regasification capacities not committed under long-term contracts also can contribute to a flexible supply of gas. Next to gas market design, thus also gas market fundamentals and the future development thereof pose additional risks that might or might not be able to be cushioned by market design.

Last, challenges in gas and electricity market design are interrelated. Often, gas and electricity peak demand coincide and both systems have to cope with system stress in an integrated fashion. For example, in a cold winter week when gas supplies might be scarce, gas TSOs might have to ration supplies for heating or electricity generation.⁴

Gas-fired power plants: Operating between gas and electricity markets

As described above, gas and electricity markets are heavily linked and viable operation of gas-fired power plants depends on both gas and electricity market design as they operate in between these two markets, with gas as input fuel and electricity as output. They are connected to both the electricity grid and the gas grid. The latter illustrates the crucial role of coordination among gas and electricity TSOs, here especially with respect to balancing. Depending on market prices, it might be worthwhile to either use gas and sell electricity, or, in contrast, to sell previously procured gas on short-term markets. Liquid and accessible balancing markets are a requirement for such short-term optimization.

When discussing gas and electricity markets, the geographic dimension and the segmentation of markets have to be taken into account. Gas only moves slowly in the pipelines, and when buying pipeline capacity market participants to some extent at the same time buy temporary storage. Accordingly, there is a regional scale to evaluate flexibility. Regarding gas, this scale is not at EU level. It is debatable what the

⁴ One participant reported that in the US this trade-off usually is solved in favor of gas supplies for heating.

“right” regional scale to evaluate flexibility inherent within the gas system is. Participants stated that such scales are probably bigger than Belgium but smaller than Germany, and hence this issue is independent of national borders but rather depends on grid topology, gas sources and sinks, and transmission grid usage patterns. Consequently, there are basis differentials that change according to region (and type) of gas. In the US, for instance, with respect to the Henry Hub, Boston basis differentials in general can be 10 cent up to \$1.5 per MMBTU. In March 2014, the Henry Hub spot price was at \$4.5 while Gas at the Boston hub was priced at \$15. Vis-à-vis such regional gas price signals, power plants located in different regions negotiate bilateral contracts and contract on short-term markets according to their locked-in electricity sales.

For electricity market revenues, in turn, electricity market arrangements are relevant. In the ISO New England market for example, CCGT can bid firm capacity. These bids create situations where a CCGT unit that is booked as firm capacity cannot get access to sufficient gas supplies, because heating may be prioritized during scarcity events. This problem is aggravated by the fact that the New England power market has a capacity mechanism without sufficient penalties for non-delivery. As an alternative, it could be required that gas-fired power plants participating in the capacity mechanisms have access to firm capacity upstream, too (via pipeline, storage, LNG arrangements or dual fuel).

Besides physical congestion, also contractual congestion can play a role in causing market frictions. When firms’ contracts eventually are not nominated, capacity may remain out of the market, leaving large opportunity costs. To counteract contractual congestion, in the new EC Network Code on Capacity Allocation certain provisions such as “use it or lose it” and limits on re-nomination for cross-border transmission capacities exist. In the US, also FERC has started to implement similar regulation and requirements on inter-state pipelines.

Physical and contractual congestion thus stress the need for efficient intraday balancing mechanisms also in gas markets. In Belgium, gas systems are balanced on a daily basis and market actors have to stay within the corridor defined by upper- and lower limits. In contrast, in Austria there used to be a requirement for hourly balancing. As the EC Network Codes prove, much policy effort today is spent on finding rules and best practice for still varying balancing designs. This also holds for the US, where Western Interstate Energy Board has opened a multi-year project to integrate gas and electricity operations.

The following section takes a closer look at gas and electricity intraday markets and their impact on the operation of gas-fired power plants.

Flexibility arrangements on intraday markets

Flexible arrangement in intraday markets for electricity

Intraday markets for electricity may be designed in completely different ways, as major differences among the US and EU approaches show. In the EU, products are separated along the time dimension – intraday prices count for intraday products only. Units that are sold on the day-ahead market receive the day-ahead market price. In the US, in contrast, virtual intraday prices are fixed after real-time as a result of a two-step clearing of the day-ahead market. Based on the first submission of bids, in a first step, the

day-ahead results are calculated. Then, deviations in demand or supply are matched based on the same bids and the final real-time price is paid to everyone who was among the winning bidders in this process. The fact that the same bids are used for a longer period of time before delivery, while in the EU markets and market prices are segmented over time is also made possible by allowing firms to submit multi-dimensional bids – up to 50 bid components may be specified, for instance including ramping and start-up costs.

Sticking to the current design also means sticking to overlapping intraday and balancing interactions. In the EU, two rolling optimization processes are covering two overlapping time frames in that balancing for fast reaction takes place inside one hour, whereas intraday all decisions for re-trading, re-dispatch and reserve management scheduled for the remaining hours in advance of final balancing.

Also cross-border short-term arrangements have to be taken into account for trading energy from flexible sources. With respect to cross-border trades, several problems arise. How can there be real cross-border competition if markets in Member States are operated by national transmission system operators, which have wide latitude to change reserve constraints? Overall, the role of the TSO as a market facilitator is not clearly defined in Europe – and many TSOs also have functions that are typically expected from market participants rather than market facilitators, for example managing the sale of wind power and implementing re-dispatch measures, dispatching the network reserve in Germany, dispatching the strategic reserves by ELIA in Belgium, or balancing measures by RTE that are also involving intraday activities.

Good intraday market design is also necessary to incentivize flexibility. A plant that is fully flexible can take opportunity with adequate intraday design and the most efficient and flexible technologies should have a comparative advantage. However, this assumes that market design is neutral with respect to different flexibility providers. A good intraday market design needs to properly remunerate flexibility while ensuring fair access for all technologies and flexibility products.

Flexible arrangement in intraday markets for gas

The fact that many gas-fired power plants, such as the 850 MW CCGT power plant in Lingen, Germany, operated by RWE, chose in-house gas storage solutions indicates that gas plant operators tend to decrease their risk of operation also by storing their input commodity instead of fully relying on short-term market supplies. Furthermore, market risks in procuring gas on short notice hold for most gas turbines, as due to technical reasons (minimum connection pressure) in general for CCGTs a connection to the transmission system is required.

Therefore it is important to shed light on what is happening on the gas side with respect to intraday capacity allocation arrangements. The new Network Code on Capacity Allocation introduces a standardized auction procedure, with one auction design at all interconnection points between market areas, auctions starting simultaneously, and individual auction processes for each individual capacity product. Besides yearly, quarterly, monthly and daily products, intraday trade allows for the procurement of within-day capacity products auctioned every hour (with a certain lead time), being a band of total capacity for the remaining hours of the gas day.

The general principle of daily balancing as defined in the Network Code on Gas Balancing implies that grid users' end-of-day positions are relevant. Moreover, TSO may offer line-pack flexibility, again following the end-of day principle.

However, with variable demand and supply, unpredictable short-term variations also for very short time horizons occur. Hence, it is debated if we need even shorter period intraday markets with standardized products until 1h before real-time, or within-day gas balancing. In this context, the additional need for coordination between gas and electricity TSOs, especially after gate closure, remains open, however. In addition to TSO cooperation, also other trade-offs arise when enhancing flexibility. For instance, making contracts quick and flexible creates an issue on the storage side, where storage facilities are not necessarily built for flexible and fast use.

Last, for traders also liquid forward markets are one means to reduce risk and fixed costs (minimize booking costs of capacity) to be able to sell back gas and to have access to storage. Flexible arrangements for forward contracting for gas-fired power plants are relevant as market actors typically rely on locking-in margins (via locking-in gas input prices and electricity output prices) via mid-term contracts. For the full hedge of a power plant naturally both sides, the costs of gas input and revenues from electricity sales and according intraday markets that provide the reference for the hedge, are relevant.

Conclusions and outlook

Besides technical solutions to flexibility, such as dual-fuel firing which can help to increase a power plant's flexibility, contractual arrangements on short- and long-term markets can help in stabilizing revenues of and investment in flexible gas-fired power plants. Such contractual arrangements may comprise maximum and minimum intake, hourly intake, and access to storage on the gas side, and a variety of intraday and reserve products on the electricity side. These short-term market arrangements for gas input and electricity output of gas-fired power plants, and how market design accommodates these transactions, were at the core of this workshop.

There are many design aspects in gas and electricity markets that regulators may investigate when unlocking flexibility and at the same time incentivizing the operation of relatively low emission-intensive gas-fired power plants. Many of these design aspects refer to the electricity market and comprise amongst others complex bids, the frequency of intraday and balancing market clearing, and the joint optimization of energy and reserve markets. On the gas side, possibilities for market design changes are less explored, and hence the success and issues arising in the further development and implementation of the new grid codes will set the scene for further discussions.

For the future, it also has to be taken into account that in the EU, with the new EC state aid guidelines, RES generation from 2017 onwards will be remunerated differently via a premium instead of fixed tariffs, which might also change the business case for large companies that own both RES and flexible conventional power plants. For instance, with a premium system, RES owned by large incumbents provides additional infra-marginal capacity to increase market power. In Spain, when feed-in tariffs were removed in 2004, large incumbents only owned 15% of new installations, while now with a premium,

85% of new installations are owned by incumbents. Thus, new market portfolios arise that change the balancing needs for market participants.

Nonetheless, there are some ways forward, for instance with improving the way energy and ancillary service markets price scarcity. The operating reserve demand that is being implemented in some markets in the US is one possibility for a better co-optimization between the energy and the reserve market. Furthermore, moving closer to regional instead of fragmented balancing markets could increase liquidity and market trust. Furthermore, nodal pricing could offer advantages. Without nodal signals, establishing efficient electricity and gas interfaces is getting more and more challenging, because local gas scarcity signals with zonal electricity scarcity signals might not be able to allocate resources and thus gas for power generation efficiently.