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Report

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Mid-term contracting in Electricity Markets: What to consider in Market Design?

Future Power Market Workshop, Brussels, 27.9.2013

Workshop report by Karsten Neuhoff¹ and Sebastian Schwenen²

SUMMARY

Decarbonization goals of the European Commission foresee different future scenarios for the European power market of which all are exceeding 60% renewables in the power system.³ High shares of intermittent renewable sources require significant changes to the physical system and impact the profitability of conventional generation. While renewable remuneration mechanisms in many European power systems typically provide long-term revenue guarantees for 15-20 years, conventional generation assets combine mid-term contracts, covering between 1-4 years, and vertical integration to reduce revenue volatility and secure operation, re-investment, and closure choices.

To this end the participants of the Future Power Market Platform reviewed the empirical situation with mid-term contracts, identified incentives to contract and discussed possible commercial and regulatory approaches to support MTC. The main conclusions are

- For generation, mid-term contracts help to secure re-investment and inform closure choices – and thus contribute to generation adequacy
- For load, mid-term contracts hedge energy (input) prices, improve revenue stability and inform (re-)investment decisions. It is however unclear whether load has capacity and incentives to sign sufficient MTC to meet needs from generation and from power systems perspective.
- Commercial approaches to increase mid-term contracting volumes can comprise for example new contracts types like option contracts
- Regulatory solutions to support MTC and coordinate investment in generation may amend existing regulation, such as with transmission contract design or retail market regulation
- Obligations towards MTC can be seen as a capacity mechanism– but equally capacity mechanisms can undermine the ability of market participants to sign MTC and thus their own effectiveness.

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³ Different scenarios include shares of renewables ranging from 60% up to around 80%, see the Energy Roadmap 2050, EC (2011).

Motivations for market participants for mid-term contracting

The importance of and incentives to signing mid-term contracts for electricity differs among various actors on the demand side, on the supply side, and from a regulatory power system perspective.

The demand side

The demand side is interested in signing MTCs

- to stabilize fuel costs to avoid volatility in household (public) budget or firm profitability
- to secure (re-)investment choices in energy intensive industries

Both effects in principle are of increasing importance with more uncertainty about future price developments linked to climate policy and RE deployment. Additional factors apply to specific customer segments.

Retail customers to large degrees do not actively hedge the electricity price in other ways than signing contracts with retailers. In turn, retailers have an interest to hedge their purchase prices and stabilize revenues. However, usually retail contracts are terminable subject to a short notice and hence retail customers might switch retailers who committed to mid-term contracts if they ex-post turn out to be priced too highly. As a result retailers limit the volume and length of contracting.

Furthermore, retailers who have hedged their customer base with MTCs against high power prices might be concerned that competitors that did not pursue similar actions are supported through regulatory intervention if power prices are very high. This reduces the incentive to pursue a prudent risk management strategy.

For **industrial load**, the economic crisis has illustrated to companies the risk of signing firm power supply at expected demand. If their production and thus power demand drops, they are long on power contracts that are likely priced above prevailing spot prices. Arguably some contracts even contained take or pay provisions preventing resell of the power.

Furthermore, incentives to sign MTCs are reduced by the fact that firms increasingly sell their products on shorter-term arrangements rather than longer-term fixed prices and thus also prefer to expose themselves to prices of input factors (e.g. power) on shorter time frames instead of signing mid-term contracts. This is of particular relevance for very energy intensive products where energy prices constitute a significant share of total production costs and are therefore reflected in product prices also of competitors and thus in the overall market price. However, while this rational fully applies to coal and oil prices – for which international competitors will pay the same price in a global market – gas and even more so wholesale power prices have strong regional price components, that might not be shared with competitors at other locations. Therefore, in principle, hedging against power price risk remains of interest.

Finally, for both residential and (to a lesser degree) industrial load, the total power price rather than the wholesale price determines electricity costs. It comprises elements like grid charges and RE surcharges

which might be difficult to predict. Therefore MTC alone might not ensure stability of the “electricity bill”.

Generation

Generation is interested in and relies upon signing mid-term contracts to hedge price volatility. In particular, for the supply side the main incentives to sign MTC are

- to stabilize revenue streams and cash flow
- to inform decisions on and facilitate financing of re-investment and closure choices.

Generally, with increasing shares of RE and thus more volatile prices the incentives to hedge increase, especially for peak-load capacity.

However, if spot prices diverge from the contract price of MTC, then the MTC will constitute a significant financial value. This can create significant counter party risk and therefore imposes high capital requirements. This is reflected in large deposits for margin calls for exchange based trade and requirements for corporate guarantees in OTC contracting. Both, the increasing difficulty to anticipate future power price developments linked to policy uncertainty and constraints on balance sheets therefore translate into a declining ability to sign MTC.

Furthermore, for small generating companies without a portfolio of generation assets, risks exist that their power station might be unavailable at the time of peak power prices, and in these instances their hedge between fuel input prices and power prices creates a financial liability.

In addition, with higher shares of RE, traditional price structures on wholesale markets are changing. Average spot prices fall below marginal costs of CCGT units. As a result those units will in due course only be contracted forward at contract prices below marginal costs. Additional revenue will thus be required from serving the contract requirements through acquiring power at wholesale prices below MC (e.g. at times of high wind production) to serve contract requirements. This however implies significant risk, as the additional revenue required for the contract to break even, depends on the number of hours for which high RE production results in very low spot prices. Traditional forward contracts (i.e. blocks of energy – base or peak) hence become less attractive for risk-averse generating companies.

Systems perspective

From a regulatory perspective,

- MTCs can help to ensure system adequacy. With power prices signaling scarcity levels in the mid-term horizon, MTC can help to avoid situations where several companies close plants simultaneously with the risk of insufficient generation capacity emerging
- MTCs indirectly enhance regulatory credibility; if customers are hedged against spot prices, regulatory intervention is less likely compared to higher exposure to peaking spot prices. This effect will be of increasing importance, if power prices are seen as a means of coordinating the power system response to periods of low RE production that could result in high prices over several days (rather than current peak prices focused in individual hours).

However, a range of challenges emerge for market actors that rely on the current contracting pattern focused on base and peak load contracts.

First, current contract types might be less suitable to inform about scarcity levels. This is because increasing shares of hours of low power prices due to surplus renewable generation have a negative effect on contract prices and partially compensate potential increases in prices linked to actual scarcity. As a consequence, price spikes cannot only be traced back to scarcity situations and hence fail to provide adequate scarcity signals. Also, with increasing PV shares providing generation at day-time peak, the traditional peak load contracts might not match the time patterns at which power supply is tight. If such hours are during periods covered by the base load contract, then the effect is averaged across large number of hours and therefore less visible.

Second, liquidity is no longer increasing and in some markets is declining. While the EEX constitutes a rather liquid market, it could also draw some of the liquidity from neighboring markets that use EEX as (imperfect) reference point. Reduced liquidity on forward exchanges furthermore decreases the value of the forward price signal as a benchmark for OTC trades. Bilateral OTC contracts can be more tailored to emerging needs of generation and load. This would however require that similar contract types are traded on exchanges, e.g. option type contracts, as their value is difficult to derive from prices of base and peak load contracts. Furthermore, with reduced liquidity of comparable contracts on exchange based agreements, contracting parties face challenges in judging whether an OTC offer is “fair”. This might especially hold for small entities on the demand side that do not employ specialized trading departments.

Third, the divergence of regional power prices increases. Increasing price differentials can be traced back to at least two reasons: (i) increasing deployment of intermittent RE with market-specific varying deployment volumes and generation patterns and (ii) high gas prices that implied that CCGT are no longer price setting across several EU countries. As a result, market participants need to contract locally or to obtain transmission contracts to neighboring countries to hedge transmission risk. However, other than a few inherited contracts, international transmission contracts do not expand to more than one year. Increasing price divergence also implies that regulatory challenges partly remain specific to different European power systems.

To conclude, MTCs are central for power systems and generation in energy-only markets (or markets predominantly operating through energy market revenues) to provide adequate signals on the profitability of re-investment and closure choices. However, it remains open whether demand has sufficient capacity and incentive in signing the corresponding contract volumes that would be desired from system and generation perspective. Overall, the picture on MTC in European power markets is blurred and data and information on OTC/MTC trades difficult to obtain.

Commercial and regulatory means to support MTC and (re-)investment

Means to support MTC are likely to be both in private hands (contract design) and depend on regulatory actions to enable additional and possibly different contracting approaches.

Evolving contract design to better meet hedging demand: To date primarily base and peak load contracts are traded on exchanges, but new contract types are emerging – for example matching the daily time profiles of solar generation. Alternative developments could involve option contracts. If the strike price is close to variable generation costs, then the generation could fully hedge annual fixed costs through the option premium while load could benefit from the optionality. The primary challenge for any such contract type is the need of sufficient liquidity that provides confidence in the price signal and allows for resell. Liquidity could be kick-started by regulatory designed option contracts (via public procurement) to ensure a visible price discovery and liquid markets.

Renewable energy remuneration mechanisms typically offer rather stable contract prices to generation, and allocate the difference between the value of these long-term contracts (from tenders for long-run contracts for renewable energy to feed-in mechanisms) and the value recovered at spot market sales through a surcharge to all consumers. This surcharge is thus increasing in periods of low and decreasing in periods of high power prices. This points to the value of integrating the RE surcharges in the risk management strategy that guides mid-term contracting of electricity load. Such integration could be reflected in a variety of approaches, ranging from as little as an integrated communication of the development of RE surcharge and power costs to a fully integrated contract for industrial load that optimizes across exposure to wholesale prices and renewable surcharge.

Improving institutional and regulatory design to facilitate increased MTC: Adjustments to the design of transmission contracts could facilitate additional MTC. Current international transmission contracts are only available for a maximum of one year. This implies that for contract durations beyond one year, liquidity and competition is typically determined by the market participants within a specified country. Given increasing congestion patterns between countries, neighboring power markets do only provide very limited hedging opportunity. If TSOs were to make transmission contracts available with longer contract durations, then this would increase competition and liquidity in all markets.

Furthermore, regulation of retail markets could be amended to encourage and support risk management procedures that result in increasing volume and duration of contracting at the retail level.

Finally, energy price caps may be reduced either through the use of bid caps, or through the strike price of strategic reserves. This would decrease counterparty risks in mid-term contracting and thus enhance the ability of generation and load to sign MTC. However, this effect needs to be jointly assessed with the impact of lower price caps on the incentive for market participants to hedge their exposure to very high peak prices that was in the past argued to be a reason for load to acquire such contracts.

Regulation imposing requirements on contracting: Various types of capacity mechanisms impose explicit contracting requirements on market participants or TSOs. These additional requirements can complement, substitute, or undermine prevailing MTC, depending on the exact market design. In order to discuss the possible interactions we characterize regulatory designs for capacity mechanisms according to two dimensions (figure 1).

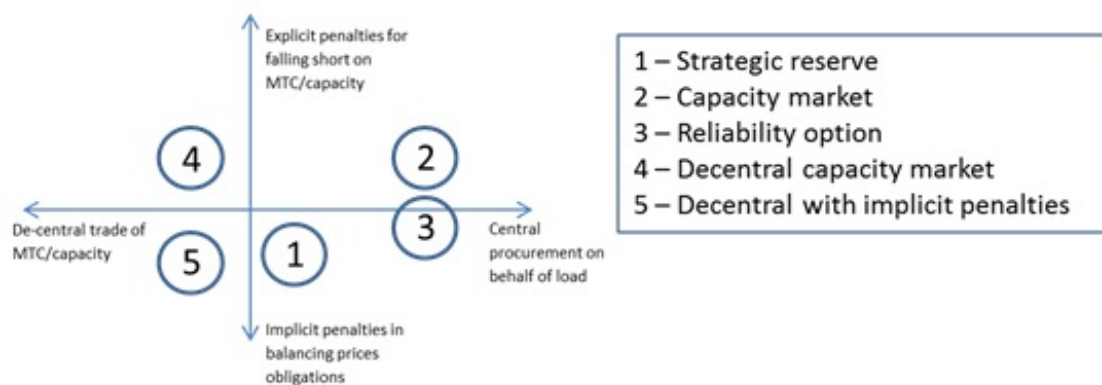


Figure 1: Dimensions of regulatory designs to support investment adequacy.

According to the first dimension, to meet the capacity requirement capacity contracts may be procured centrally, for instance through the system operator (currently TSO). In this case, the TSO signs contracts with generation on behalf of load. Alternatively, within a decentralized capacity mechanism, each individual load-serving entity would engage in contracting according to capacity requirement that are imposed through the capacity mechanism (typically linked to volume of demand served etc.).

The second dimension entails penalties for not complying with contractual obligations. Load may procure too few contracts, while generation may fail to deliver contracted capacity when requested. Without a penalty term, a decentralized capacity mechanism would merely comprise regulatory pre-specified mid-term contracts. The primary motivation for contracting is in this case hedging against volatile prices. Additional penalty terms could ensure that contracting beyond the individual hedging interest of a load serving entity is pursued, and thus additional contracting and possibly also additional generation capacity is incentivized.

Comprehensive **capacity mechanisms** such as the traditional capacity market, capacity obligations above peak demand with de-central procurement, and the reliability option, also impact MTC. With increasing shares of revenue of generation (and cost for load) provided through capacity mechanisms, the remaining revenue stream through energy markets declines. This will impact the hedging strategy, if uncertainty on future prices will less likely reflect uncertainty about scarcity price signals and more strongly dependent on fuel and carbon prices, and in the longer-term the generation mix of technology. In principle, this could facilitate contracting, because counter party risk declines in the absence of very high scarcity prices.

However, while in static perspective mid-term capacity payments provide a fixed contribution to revenue stream of generation, and clearly define the remaining revenue stream to be hedged, over time with evolving generation mix and capacity market details, it is difficult to predict what share of the total revenue stream for generation will be provided through capacity mechanism, and therefore how to hedge the remaining revenue through the wholesale energy market.

With **reliability options** a significant concern about the impact on MTC contracting emerges. Generation that has sold a reliability option has to pay the difference between the spot price and the strike price specified in the reliability option in periods when spot prices exceed the strike price. If generation would in addition contract energy on mid-term contracts, then it incurs losses during periods of peak prices. Therefore the reliability option approach would in principle undermine the incentive to sign MTC. To date, reliability options have not been implemented in market designs with significant forward contracting volumes. This might change if the proposals to shift to reliability options in New England are implemented. Here provisions are envisaged that load is relieved from the obligation to sign reliability options if it can demonstrate bilateral forward contracts with generation. However, load that has not signed reliability options will be first to be disconnected if the corresponding generation fails to deliver, and might thus be reluctant in pursuing such alternative options.

In contrast, the **strategic reserve** contracts only a minor market volume which is deployed if wholesale prices exceed a pre-specified strike price. Thus bilateral mid-term contracting is not directly impacted. In fact, the strike price of the reserve, when set low enough, can support contracting by decreasing counterparty risk, because the value of the contract is capped at the strike price. However, this has to be jointly examined with the effect of the decreasing contract volume on incentives to maintain and re-invest in peak capacity.

In general, whenever market design discourages market based contracting, the regulatory implemented hedge should serve as a substitute for market based contracting. It remains to be debated, whether fully fledged centralized or de-centralized capacity markets and reliability option designs deliver an adequate substitute to market based mid-term contracting. As hedging needs differ among market participants, a fully regulatory defined hedge might not meet all needs of load and generation. Thus market designs that leave room for additional bilateral contracting might be favorable.