December 2016

ECN-N--16-033

Required adjustments of electricity market design for a more flexible energy system in the short term

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Executive summary[1] [2]

The current electricity markets exhibit a strong day-ahead focus; in fact, they have been designed for conventional gas and coal power plants, whose availability can easily be predicted on a day-ahead basis. With the increasing share of weather-dependent renewable energy, whose predictability is more accurate in time scales that are shorter than day-ahead, the importance of short-term electricity markets is rising. The integration costs of weather-dependent renewable energy, such as imbalance and network costs, can be reduced by implementing a better market design which enables market participants to adjust their positions according to the changing circumstances and by more efficiently utilising the available flexibility of generation units and domestic and foreign demand (via interconnections).

It is not only the design of intra-day and balancing markets that is important within this framework, but so is the space that forward markets, such as the day-ahead market, offer for intra-day and real-time trade and balancing. In addition, the access to foreign flexibility is essential, in light of the progress towards a set of European markets for electricity (one market for each time horizon). A good market design takes these temporal and spatial dimensions into account.

Based on insights from the US related to the design of markets, the following three central themes have been identified as essential for market design:

a) Consistency between electricity markets for different time horizons
b) Simultaneous alignment of energy provision and reserve capacity
c) Simultaneous alignment of energy trading and congestion management

More consistency between electricity markets for different time horizons leads to a more uniform, time-related flexibility demand from market participants and to lower flexibility costs, because expensive corrections in real-time balancing markets can be partially replaced by less expensive corrections via intra-day trade. Simultaneous alignment of energy provision and reserve capacity enables market participants to arbitrate between both on shorter notice and, in doing so, increases the utilisation of the flexibility of production, demand and storage. Simultaneous alignment of energy trading and congestion management prevents sub-optimal transactions on electricity markets and, with this, the necessity for Transmission System Operators (TSOs) to correct these types of transactions afterwards by utilising flexibility to regulate upward or downward. This reduces the demand for flexibility and increases the access to flexibility supply from abroad.
The current market organisation of the Dutch and European markets is assessed on these three central themes.

[1] This note has originally been published in Dutch in February 2016.

[2] The author would like to thank the Dutch Ministry of Economic Affairs for funding. Opinions expressed in this paper are those of the author and do not necessarily reflects views of the Ministry.

Consistency between electricity markets for different time horizons
There are opportunities to adjust previously held positions on the day-ahead market at the national level into intra-day and balancing markets. The intra-day market is gradually becoming more liquid and, as a result, more advantageous for hedging previously held positions. Just like balancing, intra-day trade is possible on a 15-minute basis in the Netherlands, and the adoption of a joint, cross-border intra-day market is anticipated for 2017. The design of the Dutch balancing market stimulates market participants to passively participate in the regulation for reducing the system imbalance and, in doing so, provides market participants many opportunities for flexible provision. At the same time, consistency between successive electricity markets is hindered by the dissimilar granularity of products on the day-ahead market (DAM), the intra-day market (IDM) and the real-time balancing market (BM) (NL and EU), by different pricing rules for energy products in DA, ID and real-time BMs (notably EU; to a lesser extent NL) and by the application of proactive activation strategies by neighbouring TSOs (including in Germany).

Simultaneous alignment of energy provision and reserve capacity
Market participants can optimise their production schedules by using block bids whereby the production and accompanying flexibility are offered for several consecutive hours and the bid is only carried out if the desired average price is attained. Doing this enables them to more adequately include start-up and regulation costs in their bids and to limit the risks of an impracticable or uneconomical production schedule. By participating in the regulation on a real-time basis, market participants can also supply balancing energy to the TSO. With this, they can monetise their flexibility without having to fix the production capacity in advance and without having to make concessions in primary operating processes. One drawback is that TSOs still conclude longer-term contracts for a portion of the necessary reserve capacity, while energy products which are produced as a complement to or as a substitute for reserve capacity are purchased at shorter notice. As a result, market participants have difficulty making an adequate comparative assessment between supplying energy and supplying reserve capacity. Market participants in the Netherlands are also still obligated to make symmetrical bids for the supply of reserve capacity, which results in a lack of utilisation of the flexibility of RES and demand response. These two issues play a more significant role in the Netherlands than they do in Germany, for example. Other issues, such as a lack of or limited intra-day trade in reserve capacity and limited opportunities for the inclusion of technical and economic restrictions, such as start-up costs, in the bid format are equally important in the Netherlands and in Europe.

Simultaneous alignment of energy trading and congestion management
The Netherlands participates in the coupling of day-ahead markets in a European context whereby the *market coupling operator* (MCO) simultaneously optimises electricity trading and the utilisation of transmission capacity on cross-border interconnections on the basis of the *price coupling of the regions* (PCR) algorithm. On the intra-day market, there are various opportunities for energy trade with foreign counterparties. However, impacts on congestion are often not adequately taken into account by market operators for matching bids and offers (as network capacity often has no price). In the case of balancing, there are diverse pilot projects for the step-by-step development of cross-border trade between European countries. One problem with this is the limited amount of available cross-border network capacity on intra-day and real-time bases. This limits opportunities for cross-border trade in energy and capacity products. Furthermore, available network capacities for implicit auctions

are still dependent on the expected utilisation of generation units at the time of capacity calculation, even when applying a flow-based network representation. This limits the utilisation of foreign flexibility via interconnections. And finally, the difficulties of adjusting bidding zones are underestimated, so that the delineation of bidding zones insufficiently reflects the structural network restrictions thereby lowering market efficiency.

There are various possibilities for solving the issues outlined above for each of these three central themes. It is assumed that these possibilities pertain to the pursuit of one internal electricity market and therefore to the transition from decentralised national markets to more centralised markets at the regional level (Northwest Europe) and, subsequently, to Europe-wide markets. We will limit ourselves here to the first two central themes and refer the reader to Smeers (2008) for an outstanding, in-depth discussion of the third central theme. For the other two themes, the following seven important policy options have been identified for the improvement of the design of electricity markets.

Consistency between electricity markets for different time horizons

1. **Shortening the time resolution of day-ahead market products to 15 minutes**
   To better meet the need for energy products with greater flexibility, day-ahead products, in addition to balancing and intra-day products, must also be settled on a 15-minute basis. There do not appear to be any obstacles for additional DAM products with 15-minute time resolutions on the national or regional power exchanges. Adoption in an EU context can probably only occur in 2018. A disadvantage of DAM products with 15-minute time resolutions is that due to operational limitations such as ramping, conventional power plants will often be insufficiently flexible to adjust the quantity of energy to be supplied for such short periods to the development of the energy prices. To prevent higher imbalance costs, conventional power plants must offer their production by making use (on a larger scale) of block bids for groups of hours. An open question is whether block bids can be used on larger scale or whether this will result in the creation of insurmountable problems in price-setting.

2. **Stimulation of cross-border trade through marginal pricing of energy products over all time scales in (Northwest) Europe**
   With marginal pricing, all energy is traded at the marginal price whereby supply covers demand. A lack of harmonisation between countries in the pricing of both energy and capacity products is one of the factors that hinders the access to foreign flexibility for different time scales and, with it, the frequent adjustment of (cross-border) energy positions. In the European target models, marginal pricing is provided for energy products in day-ahead and balancing markets. The price coupling algorithm of the day-ahead market assumes marginal pricing of energy and network capacity and is already applied throughout a large part of Europe. In coming years, this algorithm will be rolled out in the remaining European regions. Marginal pricing of energy is foreseen for the energy balancing market within a year after entry into force of the anticipated European Regulation on Electricity Balancing (probably as of 2018).

   Marginal pricing of energy in the intra-day market is not explicitly provided for in the target model, but appears unavoidable due to the choices for pricing of network capacity and the application of flow-based network capacity calculations in which the effects of a transaction on the available network capacity for other translations is taken explicitly into account. This requires simultaneous optimisation of a set of transactions and, with that, trading at set times. Therefore, the advice to policy-makers is to adjust the capacity allocation and congestion management (CACM) regulation with regard to continuous trading and, with that, to make marginal pricing of energy traded on an intra-day basis possible.

3. **Adoption of balancing markets with reactive TSO activation strategies in (Northwest) Europe**
   Application of a reactive activation strategy by TSOs provides market participants with the flexibility to adjust energy programmes right up to or in real time. With this approach, TSOs activate bids in reaction to the momentary system imbalance and not ahead of time based on the expected system imbalance. Individual generation units may deviate from scheduled production or consumption on the condition that the portfolios in which they are included are still in balance. In addition, market participants may deviate from their portfolios on the condition that they reduce the system imbalance ('participate in the regulation'). When applying a reactive activation strategy, negative imbalance (less production or greater consumption than planned) is not penalised more than a positive imbalance.

   The current draft of the European Network Code on Electricity Balancing (NC EB) (ACER, 2015a) contradicts this on some points. It seems probable that the gate closure time (GCT) of the balancing energy market will lie quite far for real time and close to the gate closure time of the intra-day market, so that market participants are no longer able to participate in the regulation on a real-time basis. Furthermore, it is still unclear whether market participants will have the opportunity to contribute to the recovery of the system balance or if they may only strive for bringing their own portfolios into balance. EZ, TenneT and ACM have a role to play in convincing foreign and European stakeholders that market participants must be able to contribute at all times to the recovery of the system balance and must always be able to supply balancing energy in real time.

4. **Stimulation of cross-border intra-day and balancing markets by means of dynamic allocation of cross-border network capacity**
   Dynamic allocation of cross-border network capacity means that the anticipated value of cross-border network capacity for trading is compared mutually in day-ahead, intra-day and balancing markets. The network capacity is then allocated over the different market segments in such a way that maximum social welfare is achieved. As a result, more network capacity is likely to become available for cross-border trading of intra-day and balancing products. With that, the IDM and BM liquidity increase, and participants are better able to hedge positions they have taken on forward and day-ahead markets against the greater variability and unpredictability of weather-dependent electricity production from wind and solar. Dynamic allocation of cross-border network capacity can occur during closing of the day-ahead market or partly at a later time with the help of energy options. An energy option provides the choice between trading energy now or at a later time. This gives market participants greater opportunity to react to changing system conditions, such as the availability of wind energy. Given the bundled sale of energy and network capacity in an implicit auction, transmission rights are also part of the option. Consequently, not all transmission rights will be definitively allocated in the day-ahead market, but some of them will be assigned an option quality and will be

allocated at a later time. This does imply that some of the day-ahead schedules are less physically established, causing TSOs to experience greater uncertainty about which generation units will be utilised the following day at which locations and, with that, greater uncertainty about the resulting electricity flows. This translates into a greater need for flexibility in order to keep the system and the networks secure and stable in the event of any deficiencies or excesses of energy and in the event of any network component failures. On the other hand, the available flexibility supply in markets close to real time is increasing as anticipated with the development of demand response and storage. TSOs should only contract additional reserve capacity if this supply is demonstrably insufficient to provide for the flexibility demand. Furthermore, research, including market and system simulations, is necessary to attain better insight into flexibility demand and supply close to real time. For the adoption of energy options, the designs of intra-day and/or balancing markets must converge sufficiently between countries. If that is not the case, the intra-day or balancing prices (and with them price differences between zones or countries) are not a good indication of the needs for flexibility, and, as a result, there are no good reference prices against which market participants can hedge. Cross-border energy options could first be adopted within the NWE region (for energy options that are exercised on the intra-day market) or in *coordinated balancing areas* as an intermediate step towards pan-European adoption.

Simultaneous alignment of energy provision and reserve capacity

5. **Adoption of similar gate closure times for energy and reserve capacity markets for the purpose of stimulating day-ahead and intra-day trading in reserve capacity**
   By means of adopting similar gate closure times for energy and reserve capacity markets, market participants can make a better trade-off between supplying energy and supplying reserve capacity. Since the uncertainty about the yields in the alternative market ('opportunity costs') will decrease as will the risk premium, this will probably lead to lower prices for the supply of reserve capacity. Market participants, in particular new flexibility providers, such as storage and demand response, will also have more opportunities for day-ahead and intra-day capacity bids. TSOs will have more opportunities to contract reserve capacity on shorter-term time scales, preventing the contracting of too much reserve capacity on the longer term, given the higher uncertainty margins further away from real time.

6. **Evaluation of block bids and comparative analysis with multi-part bids**
   With advanced block bids, such as load gradient, minimum income condition and profile block bids, impracticable or uneconomical production schedules could be prevented, also in a future with less predictable daily demand curves. However, the question is whether participants with new flexibility supply, such as demand response, are able to express their flexibility sufficiently in these types of block bids. With multi-part bids, it is possible that various economic and technical limitations are more readily taken into account. Further research into the limitations of block bids and into the pros and cons of the adoption of alternatives, such as multi-part bids, is needed.

7. **Abolishment of symmetrical bids for reserve capacity products**
   In the Netherlands, capacity for FCR and aFRR is contracted on the basis of symmetrical bids. This means that participants must be able to supply upward regulating as well as downward regulating capacity. This hinders the participation of parties for whom it is not

economically profitable to supply both types of reserve capacity, such as RES. Separate pricing for upward regulating and downward regulating capacity is already being pursued by ENTSO-E and is also part of the draft EB Regulation.

Implementation plan
During this study, it appeared that on the basis of European legislation and regulations various policy measures would be adopted in the next 5-7 years, in particular the European regulations in the form of Network Codes for CACM and EB (the latter is still a draft).
As a supplement to this, we propose the following policy measures:

- Shortening the time resolution of day-ahead market products to 15 minutes
- Marginal pricing of products in the intra-day market
- Implementation of similar gate closure times for energy and reserve capacity markets for the purpose of stimulating day-ahead and intra-day trading in reserve capacity
- Stimulation of cross-border intra-day and balancing markets by means of dynamic allocation of network capacity and room for energy options

These measures have been proposed from the standpoint of the belief that adjustments to the electricity system will occur incrementally, with the current situation as the starting point ('brownfield' instead of 'greenfield' situation). Adoption of these practical policy measures may take place in the next five to ten years.

Suggestions for further research
Further research would be useful for the implementation of some of the aforementioned policy measures. Likewise, research into the need for additional policy measures, in addition to those mentioned above, is also conceivable. In this research, the following (policy) queries are important:

- Can block bids be used on a larger scale? Do multi-part bids have significant advantages over block bids?
- Is marginal pricing of capacity products desirable?
- Can energy and reserve capacity be optimised adequately in two simultaneous markets, or is one integrated market required?
- Is there sufficient flexibility supply close to real time to make dynamic allocation of network capacity possible?
- To what extent does the organisation of the market (e.g., pre-qualification requirement for the supply of reserve capacity, the design of block bids) hinder access to flexibility markets for demand response?
- What are the current and anticipated future business models of market participants on various sub-markets of the wholesale electricity market?
- What are the possible effects of a different market organisation on the future business models of providers of flexibility options (producers, aggregators of decentralised production and demand response, storage owners)?
- Is it possible to map out these effects quantitatively with ECN's COMPETES Model with which electricity markets are modelled? If so, how?

Contents

1. Introduction and problem formulation

The current electricity markets have been designed for conventional gas and coal power plants, whose availability can easily be predicted on a day-ahead basis. Future electricity markets will contain higher proportions of weather-dependent renewable energy which, by definition, is less predictable. This leads to increasing deviations between predicted and actual electricity production, to higher imbalance costs and, with these, to decreasing efficiency of day-ahead markets. Furthermore, higher proportions of weather-dependent electricity production combined with increasing electricity trading as a result of European market integration do have implications for electricity networks. Because the use of these networks is derived from production, trade and demand, this is also less predictable on a day-ahead basis. This results in gradually decreasing availability of interconnection capacity for the purpose of trading between countries and in more out-of-market actions, such as redispatch between and within countries.

Imbalance costs and other types of integration costs from intermittent RES-E can be reduced by means of a market design that enables participants to buy and sell electricity closer to physical delivery in real time. For such a market design, the extent to which market participants are allowed to react flexibly to less predictable electricity production is key. This holds not only for the design of intra-day and balancing markets, but, in particular, for the space that day-ahead markets offer for intra-day trading and real-time balancing. The following research question is a natural extension of this: **How can adjustments to the design of (short-term) electricity markets better facilitate the integration of weather-dependent electricity production?**

This paper attempts to answer this question by way of the following steps. First, after this introduction, the current market design in the Netherlands and in the EU are discussed (Section 2). This is followed by an analysis of the increasing need for flexibility in intra-day and balancing markets (Section 3). After that, three central themes in the design of electricity markets will be discussed, inspired by the market model that is being used in liberalised markets in the US (Section 4). In Section 5, we indicate what this means in relation to the market design for each theme, and then we discuss, per theme, the barriers and opportunities for improvements in the Dutch and European contexts. Section 6 summarises the policy implications in an implementation plan and provides suggestions for further research.

2. Current market design of Dutch and cross-border markets

Electricity is traded on various markets. These markets range from a year or more ahead, a month ahead or a day ahead to intra-day and real-time balancing markets.

For the purposes of trading electricity with relative degrees of flexibility, we make distinctions between the following markets: forward and future markets (year-, month- and week-ahead), day-ahead market, intra-day market and balancing market.

Forward and future markets
Forward and future markets serve to limit as much as possible the price risks related to purchasing and selling electricity. With a long-term contract, an electricity seller aims to protect himself against the risk that prices will decrease closer to physical delivery, and a buyer against the risk that prices will increase closer to physical delivery. On an Over-the-Counter (OTC) market (i.e., via an agent) and the electricity power exchanges, forwards and futures can be purchased for one or more years ahead, months ahead or weeks ahead. When the time for delivery approaches and the actual market price is lower than the agreed upon forward or future price, the seller can fulfil its contractual obligation by exercising the flexibility option to purchase electricity instead of generating it himself.[3]

Long-term contracts can also be concluded with foreign participants. But since prices in foreign countries often differ from Dutch prices due to network restrictions, market participants face pricing risks. These risks can be hedged by the purchase of transmission rights. Transmission rights represent a value if a price difference exists between two countries or bidding zones due to congestion. There are physical and, to an increasing extent, financial transmission rights called PTRs and FTRs, respectively.

PTRs make bilateral provision between producer and consumer possible over a congested connection. For the right to transport electricity over the connection, a fee must be paid to the relevant TSOs. Without PTRs, trading becomes imbalanced in the markets on both sides of the border. With physical transmission rights, the owner of the right must nominate, or inform, the TSO of the allocated transport capacity on a day-ahead basis, including which portion of the allocated transport capacity the owner wants to utilise (ACM, 2015b).[4] After nomination, the holder of the right must physically supply the electricity by generating it himself or by purchasing it. Nominated capacity is deducted from the transport capacity available for the day-ahead auction. Transport capacity that is not nominated is usually made available for the day-ahead auction by means of the 'Use-it-or-sell-it' (UIOSI) principle. The holder of the PTR then loses the right but, in return, receives the financial value of the resale of the capacity in the day-ahead auction.

FTRs do not have to be nominated by their holders. Instead, they are automatically entitled to payments equal to the price difference times the volume to be transported between the market areas. This product is equal to the congestion rents in the event of market coupling

[3] An electricity seller will also attempt to safeguard himself on the procurement side by fixing the gas or coal price. This is known as a so-called natural hedge due to the positive correlation between a higher fuel price and a higher electricity price. The opportunity to benefit from this hedge is lacking when electricity is generated from sustainable sources.

[4] Article 5.6.11.

through an implicit auction. In fact, an FTR is a claim on the congestion rents. For the producer, this makes the benefits of exporting to an area with a higher electricity price equivalent to those of selling the energy at a lower price plus collecting the FTR payment. And in a comparable manner for the consumer, the right makes the benefits of importing from a area with a lower electricity price equivalent to those of purchasing the energy at a higher price plus collecting the FTR payment. FTRs are so-called *spread options* and, as opposed to PTRs, have no physical significance. The holders of FTRs receive the payment regardless of their participation in the electricity market (Booz *et al*. 2011).

Day-ahead market

When liberalising the electricity market, a commonality has been sought with the design of the Scandinavian market, i.e., Nordpool. Within the Nordic region, the day-ahead market has an important position, given the magnitude of hydroelectric power with its accompanying storage possibilities. This results in a reduced need for markets with shorter time horizons (Smeers, 2008). Another reason for the important position of the day-ahead market is the need for optimisation of the contribution of generation units ('unit commitment') on a day-ahead basis; after all, the start-up and upward regulation of a large-scale power plant, such as a coal power plant, easily requires an entire day.

In the Netherlands, market participants have until 12:00 on the day preceding physical provision to present demand and supply electricity orders to the day-ahead market (ACM, 2015b).[5] The Dutch day-ahead market is coupled to the day-ahead markets of 18 other EU Member States with the same gate closure times by way of the *Price Coupling of the Regions* (PCR) project. The market coupling process has been organised in such a way that the objective of the power exchanges and TSOs is to maximise social welfare,[6] given trading orders and network restrictions. Since energy and transmission capacity are traded jointly, this can be considered an implicit auction.[7]

Roughly speaking, there are two options for market coupling: price coupling and volume coupling. With *price coupling*, information from the TSOs (available interconnection capacity) as well as from electricity auctions (order books) is used to calculate the volumes to be traded and the market prices. In the case of price coupling, this occur through one central system, while with *volume coupling*, the volume traded between countries is determined and then a separate market price is calculated by individual energy exchanges. The target model for the EU is price coupling, which is also applied within the aforementioned PCR project.

With EC (2015a), flow-based market coupling (FBMC) is provided in various areas with meshed grids, such as in the NWE and the CEE regions, while coordinated NTC-based market coupling may only be utilised in specific areas where, assuming the same level of operational

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[5] Article 5.6.19.1b.

[6] Because market coupling occurs per market for one time horizon (here: the day-ahead market), the maximisation of social welfare also occurs per market. Therefore, the effects of day-ahead maximisation on other prices (futures, intra-day) are not taken into account.

[7] With an explicit auction, the transmission capacity is auctioned first, followed by the electricity itself. The time difference between the two actions may result in the purchased capacity not being able to be utilised efficiently, because electricity prices have changed in the interim. It is also possible that the network capacity is contracted in the wrong direction (for example, from country A to country B, while the difference in electricity prices between the two countries indicates that electricity should in fact be contracted from country B to country A). Therefore, an implicit auction in which network capacity and electricity are traded simultaneously is more efficient.

network security, the application of the flow-based method has proven to be less efficient (EC, 2015a).[8] FBMC has a variety of benefits with respect to the available transfer capacity (ATC) method. These benefits include making the most interconnection capacity available where price differences between countries are greatest, higher security of supply by means of the explicit inclusion of parallel flows[9] and greater transparency about network limitations.

Intra-day market

After the closing of the day-ahead market (i.e., after gate closure), market participants can trade electricity on the intra-day market. As yet, the intra-day market is primarily a correction market for the fine tuning of previously taken positions on the day-ahead market and other forward markets. Not only are standard hourly products traded, but products which cover several hours or products which include start-up costs, such as block bids[10], are also possible. Intra-day trading may also take place with Belgium, Germany, Norway and the United Kingdom, although trade with each of these countries is designed in different ways, in anticipation of the realisation of the European target model for the intra-day market by 2017. Intra-day trading differs with regard to the availability of various types of trading platforms (OTC versus organised power exchanges), gate closure times and auction methods (energy and network capacity separate or bundled).

Electricity trading occurs via both the APX power exchange and, to a lesser extent, the OTC markets. OTC trading still occurs for transactions within the Netherlands and with Germany and the United Kingdom and offers market participants a great deal of freedom for tailor-made transactions. However, pursuant to the financial EMIR legislation, the clearing of transactions is obligatory. This results in the reduced appeal of OTC trading in which such clearing has not yet occurred when compared to trading via a power exchange, where clearing houses are standard. The cross-border intra-day trading of the Netherlands with Belgium and Norway already occurs entirely by way of an organised market(APX).

Trading frequencies and gate closure times vary even more for the various geographical markets. Intra-day trading within the Netherlands is possible for hourly as well as 15-minute products up to 5 minutes before actual provision takes place ('real time').[11] On the day preceding the transport, the Dutch intra-day market opens at 21:00 at the very latest for the following 24 hours. The time interval between day-ahead gate closure time and intra-day trading opening time is required for network security analysis (NMa, 2011).[12] With regard to

[8] See Article 20(2) and Article 20(7). In order to utilise coordinated NTC-based market coupling, permission from the relevant regulators is also needed.

[9] The flow-based method takes into account the physical consequences of commercial flows by means of Power Transfer Distribution Factors (PTDFs) and available margins in critical network elements. Given commercial flows between bidding zones, PTDFs are determined for all critical network elements. An examination is made of which transactions with their accompanying net-positions (positive is export, negative is import) are possible. For each critical network element, the PTDF multiplied by the net-positions of the various pricing zones must be less than the available space for day-ahead flows ('available margin'). In the case of congestion within countries that influence cross-border connections, this affects, by way of the PTDFs, the magnitude of the security of supply domain (also called the available capacity domain). In the case of congestion on cross-border connections, this results in differing market prices in bidding zones, and transactions with the lowest contribution to the social welfare are cancelled. Therefore, prices are only linked to commercial transactions between bidding zones. This is a consequence of the copper plate approach whereby it is assumed that transmission capacity *within* zones is infinite and that all generation units *within* zones can provide equally well for the demand, regardless of their locations.

[10] EC (2015a) calls these non-standard intra-day products.

[11] See https://www.apxgroup.com/trading-clearing/continuous-markets-intraday/

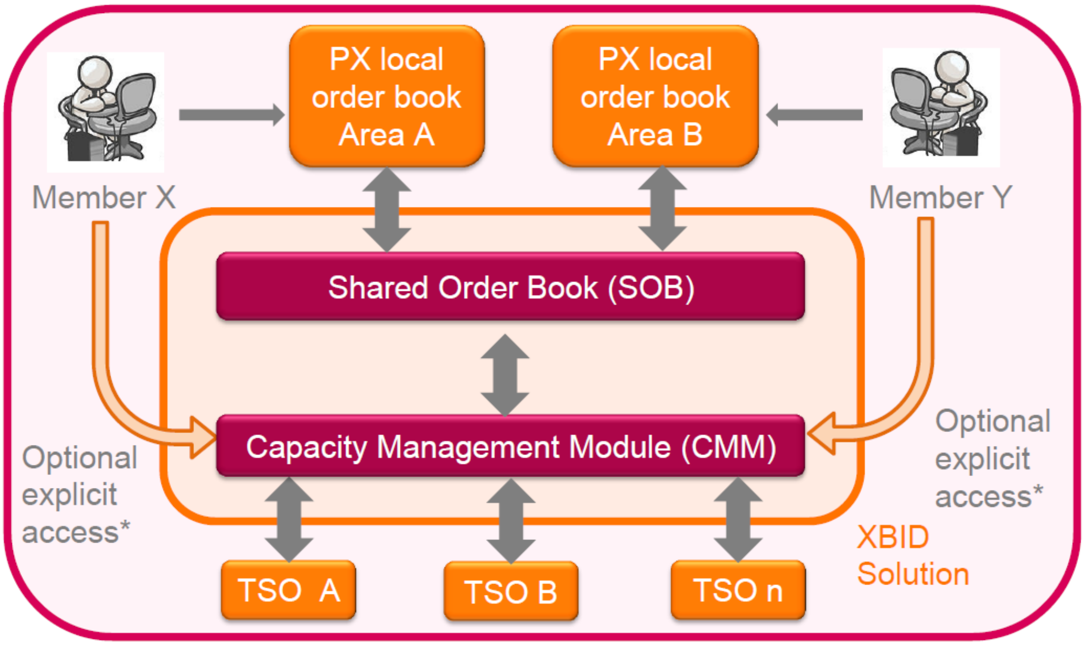
[12] Marginal 66.

cross-border trading, the trading with Belgium occurs on a two-hourly basis. This trading closes 1 hour and 30 minutes before transport on the even hours and 2 hours and 30 minutes before transport on the uneven hours (ACM, 2015b).[13] Dutch market participants may trade with German and Norwegian parties every hour up until 70 minutes (Amprion & TenneT, 2013) and 1 hour, respectively, before transport occurs (ACM, 2015d). With the United Kingdom, trading may occur twice a day on an intra-day basis up to a maximum of 4 hours before real time; both auctions have three nomination options (ACER/CEER, 2015).[14] For cross-border intra-day trading, traders primarily use residual network capacity after the day-ahead market. No cross-border (cross-zonal) network capacity is reserved for this in advance by TenneT, although TenneT does recalculate the network capacity on the borders with Belgium and Germany after the closing of day-ahead trading. Due to reduced uncertainty, this may result in an extra intra-day capacity of 200 MW on the border with Belgium and 100 MW on the border with Germany (ACER/CEER, 2015).

With regard to the auction method for network capacity, implicit trading occurs on the borders with Belgium and Norway, while the trading is explicit on the borders with Germany and the United Kingdom. In addition, the former borders have a *continuous auction*; in other words, energy trading and allocation of cross-border network capacity occurs continuously instead of by matching purchase orders and sales orders at specific points in time (E-bridge, 2010). To do this, power exchanges (PX) use a Shared Order Book (SOB) module which bundles the purchase orders and the sales orders from various countries. TSOs keep track of the available network capacity and update this, as needed, in the Capacity Management Module (CMM). Cross-border orders are matched as long as network capacity is available (given continuous trading and, in fact, on a first-come, first-serve basis). As a result, network capacity has a price of nought. This is nearly entirely in line with the EU target model that is foreseen for the intra-day market; see Figure 1. The only difference is that the option is left open for the network capacity to also be priced explicitly, in part, in order to allow OTC trading to remain possible. The regulators of the relevant Member States must request this, though, from the relevant TSOs (EC, 2015a).[15] In the longer term, the intention is to replace explicit capacity allocation by non-standard intra-day products within the implicit auction (EC, 2015a).[16]

[13] Article 5.6.26.
[14] Marginal 532.
[15] Article 64.
[16] Article 65.

Figure 1: EU intra-day market model



Source: ENTSO-E (2015b)

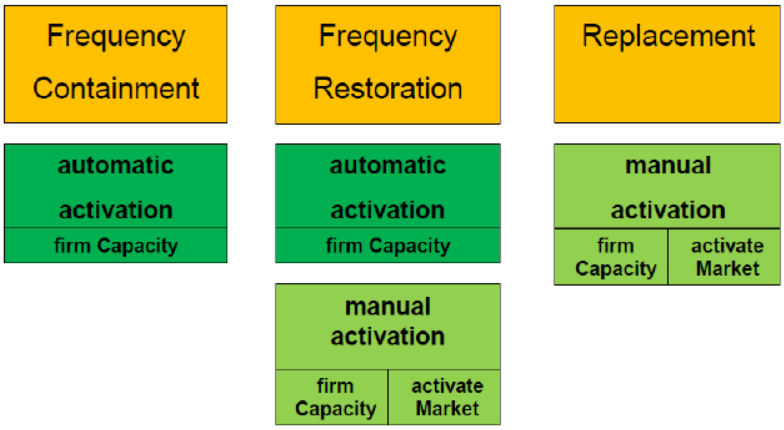
Balancing market
Balancing is defined as all actions and processes with which TSOs guarantee that the total electricity take-off is continuously equal to the total feed-in, in order to keep the system frequency within a pre-defined stability range. This results in a need for capacity reserves for balancing on various time scales, i.e., frequency containment, frequency restoration and reserve replacement. These three types of reserve products are defined as follows:

- ‘frequency containment reserves or 'FCR' means the spinning and non-spinning reserves activated to contain system frequency after the occurrence of an imbalance;
- ‘frequency restoration reserve or 'FRR' means the active power reserves activated to restore system frequency to the nominal frequency and a synchronous area consisting of more than one LFC[17] area power balance to the scheduled value;
- ‘replacement reserves or ‘RR’ means the reserves used to restore or support the required level of FRR to be prepared for additional system imbalances, including operating reserves’ (EC, 2015b).[18]

These reserves are employed in a sequential process; in summary, TSOs first utilise FCR, after which FCR is taken over by FRR and, finally, by RR. Figure 2 shows the relationship between the three types of reserves and whether TSOs activate these automatically or manually (e.g., by means of a telephone call).

[17] LFC stands for Load Frequency Control
[18] Article 3.

Figure 2: Three types of reserves and their sourcing



Source: ENTSO-E (2014b)

TSOs deploy the balancing market to balance the electricity system in real time. The balancing market consists of three important parts:

1. Balancing responsibility
2. Provision of balancing services
3. Imbalance settlement[19]

Balancing responsibility

In the case of balancing responsibility, market participants or a chosen representative party bears the responsibility for their imbalances. For this purpose, they must set up energy programmes for production and consumption, submit these daily before 14:00 to TenneT (imports, exports and transits before 9:00) and act in conformity with these energy programmes. Balancing responsible parties (BRPs) usually have large portfolios containing a combination of generation and demand. They have the opportunity to correct previously held positions by submitting changes to domestic transactions of approved programmes up until 10:00 on the day after provision ('ex-post nomination') (ACM, 2015a).[20] For that purpose, they trade with other BRPs, or they make use of the flexibility within their own energy portfolios. Deviations from final programmes result in differences between predicted and realised energy production or consumption and therefore lead to imbalances.

Provision of balancing services

To neutralise the imbalance, TSOs contract balancing services. We make the distinction here between two groups of balancing services or products: reserve capacity and energy. Generally speaking, reserve capacity is supplied by contracted participants, while qualified participants (*balancing services providers* or BSPs), which are either contracted or non-contracted participants, make bids on a voluntary basis for upward and downward balancing energy products. The TSOs' need for reserve capacity varies per product, as do the pre-qualification requirements and types (and height) of the compensation.

The *frequency containment reserve* (approx. 110 MW) is purchased weekly on a German auction platform (www.regelleisting.net). A minimum of 30% of this must be supplied within

[19] Freely adapted from Mott MacDonald (2013).
[20] Article 3.6.19.

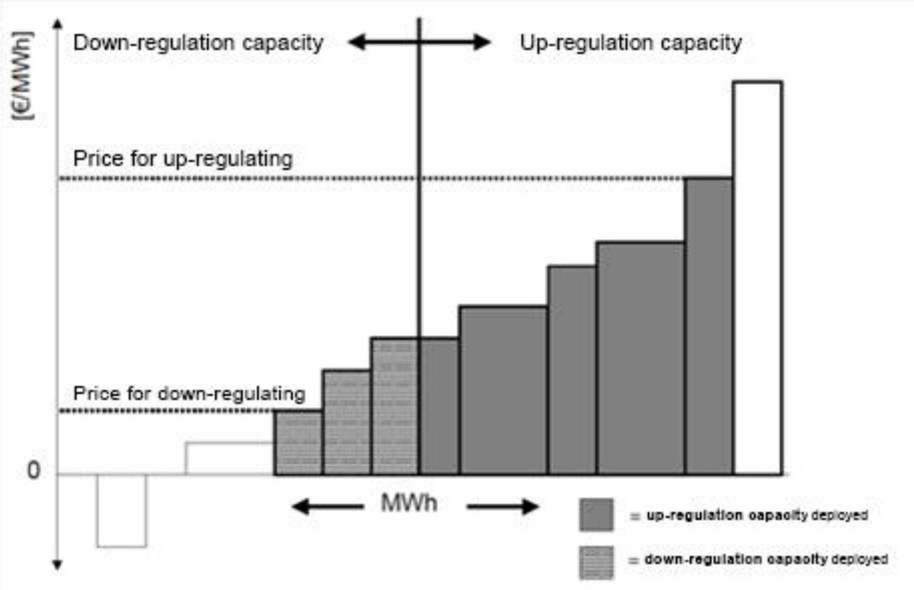
the Netherlands. The contracted party receives a payment on a pay-as-bid basis for the capacity it makes available (ACM, 2015a).[21] The minimum size of the bid to regulate upward or downward is 1 MW, and only qualified participants with automatic frequency regulation and 100% availability within 30 seconds may participate (TenneT, 2015b).

With regard to the *frequency restoration reserve*, TenneT contracts part of the regulating and reserve capacity (approx. 300 MW, for 2016 215 MW; see TenneT (2015a)) outside the market to prevent balancing capacity from competing with electricity trading and thereby being unavailable during times of peak demand. To this end, yearly and quarterly auctions are organised. Market participants that produce or consume more than 60 MW are obliged to provide their capacity as well as the surplus or deficit of energy that can be generated the following day for bidding. The affiliate can adjust the magnitude (by a minimum of 4 MW) as well as the price of his energy bid upward up until an hour before the programme time unit to which the adjustments pertain (ACM, 2015c).[22] Contracted market participants receive capacity compensation for the making capacity available. Market participants that produce or consume less than 60 MW may, on a voluntary basis, provide energy for bidding on the market for regulating and reserve capacity.

A bid ladder is constructed on the basis of the obligatory and voluntary energy bids which can be made within 15 minutes (see Figure 3). The bids are ranked on the basis of price and direction. Bids to regulate downward are depicted on the left side of the bid ladder, and bids to regulate upward are on the right. The position of the bid on the bid ladder (and any additional requirements, such as network location and regulation speed) determines whether the TSO calls the bid (Mott MacDonald, 2013; Van der Veen, 2012).[23] TenneT does not take into account whether the bid pertains to reserve capacity from a contracted or from a non-contracted party. The upward regulating bids are deployed by TenneT in the order of increasing bid price, while the downward regulating bids are deployed in the order of decreasing bid price. (The latter is related to the fact that the generation unit usually pays to regulate downward, and this, after all, saves fuel costs.) The price per direction is the bid price of the marginal bid in that direction. Therefore, the upward regulation price is the price of the highest bid that is accepted and therefore deployed, and the downward regulation price is the price for the lowest bid deployed. Participants receive an energy allowance for their physical, measured deployment.

[21] Article 2.2.19.
[22] Article 5.1.1.1a.1.
[23] Based on Mott MacDonald (2013), glossary.

Figure 3: Example of a bid price ladder for determination of the imbalance (per PTU)



Source: DTe & TenneT (2004) (translated by ECN)

Another component of the FRR is the emergency capacity. This capacity is only used if the regulating and reserve capacity is insufficient. TenneT needs 700 MW of emergency capacity. Of this capacity, 350 MW is available via mutual TSO support (Germany and Belgium), and 350 MW is contracted in the Netherlands (TenneT, 2015b).[24] The minimum bid size is 20 MW (may also be a product of aggregation), and contracted participants receive a capacity compensation (pay-as-bid). In this case, the energy allowance is equal to the maximum of the upward regulating price plus 10% *or* the APX price from the previous day plus 200 euros (in the cases of a negative APX price, the minimum allowance is 200 euros) (TenneT, 2013a).

Finally, TenneT counts on the passive contribution of market participants to the system balance (TenneT, 2013b). In addition to offering regulating, reserve or emergency capacity, market participants can also react to the real-time imbalance signal, the so-called balance delta, by voluntarily participating in the regulation. The benefit of participating in regulation is that participants need not bind themselves contractually ahead of time, and they can be more flexible in their commitments in light of coupled heat- or process-driven production or demand (DTe & TenneT, 2004). The balance delta represents the sum of the reaction requested from suppliers of regulating capacity (by means of the frequency-capacity regulation) (ACM, 2015a)[25] and is published every minute on the TenneT website. With the balance delta, market participants that do not offer any regulating, reserve or emergency capacity are encouraged to supply flexibility, so that more flexibility is made available for the electricity system. Approximately 2 GW of flexible upward and downward capacity are used for participating in the regulation.[26]

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[24] This relates to upward regulating emergency capacity. TenneT has also recently received permission to contract downward regulating emergency capacity.

[25] Article 3.9.1g.

[26] Estimate based on Ecofys (2014): given a total of 2400 MW of [RR sic] capacity, 350 MW of which is emergency capacity, approximately 2 GW is used for regulation.

Imbalance settlement
The third component of the balancing market relates to the settlement of imbalances from BRPs with the TSO. The balancing market is, in essence, a correction market. Deviations from the planned energy programme are settled for a specific time unit. In principle, this settlement can occur at a marginal or 'pay-as-bid' price.

For FRR energy in the Netherlands, one or two imbalance prices are set for each programme time unit (15 minutes), depending on the regulation status (upward regulation or downward regulation) and the direction of the imbalance of the BRP relative to the system imbalance. Usually this leads to one imbalance price, except in the specific situation in which the TSO requires both upward and downward regulation within the programme time unit in order to maintain the system balance. In that case, there are two separate imbalance prices: one for the feed-in and one for the take-off. Both situations provide the correct financial incentives to market prices. In the first case, participants can participate in the regulation and profit from deviations to their programmes as long as this improves the system balance, while in the second case, market participants are encouraged to remain close to their programmes (TenneT, 2014).

Harmonisation of balancing practices in Europe
In Europe, the aim is to achieve convergence of national balancing practices and to make cross-border balancing possible. Balancing is one of the European target models for the establishment of the internal energy market. A European Regulation on Electricity Balancing (EB) is also being developed (for the most recent version, see ACER, 2015). Main points of this regulation are (TenneT, 2013b):

- Imbalance netting: A process to prevent simultaneous, oppositional activation of FRR by taking into account the relevant frequency restoration control errors and the activated FRR and to use them to correct the input for the frequency restoration process.
- TSO-TSO model: A model in which the exchange of balancing services between countries is organised exclusively via TSOs (and therefore not via BSPs).
- Coordinated Balancing Areas: Cooperation between two or more TSOs with regard to the exchange of balancing services, the sharing of reserves or the imbalance netting process.
- Common Merit Order Lists: The formulation of joint bid ladders for a coordinated balancing area, in other words, for several countries.

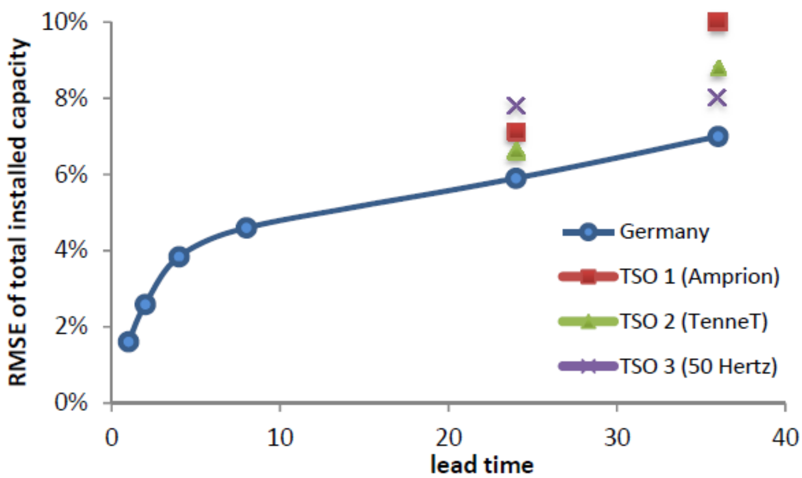
3. Increase in imbalance and decrease in interconnection capacity demands a greater role for intra-day and balancing markets

The increase in electricity production from wind turbines and solar panels leads to greater imbalance and lower availability of interconnections for electricity trading.

Greater imbalance…

Imbalance results, for the most part, from prediction errors due to uncertainty about demand profiles, from power plant failures and from the production from wind turbines and solar panels. In the case of renewable electricity, the further the production from real time that the production is traded (the lead time), the greater the average prediction error and the greater the imbalance. Figure 4 shows that the average prediction error for Germany, expressed here as the *root mean square error* (RMSE),[27] decreases from 5.9% of the installed capacity 24-hours ahead to 3.8% at 4 hours ahead. What can also be seen here is that the prediction error decreases as the imbalance is viewed over a larger geographical area. The imbalances of subsections of larger areas then partly offset one another, with a smaller aggregated imbalance as the result. Given that the prediction error of wind capacity is substantially higher than that of conventional power plants, the prediction error of the system as a whole also rises with the increase in the quantity of installed, weather-dependent generation capacity. At the limit, the system prediction error converges with the prediction error of wind and solar by a certain lead time (Weber, 2010; Mott MacDonald, 2013).

Figure 4: Prediction error of electricity production by wind turbines as a function of the time before real time



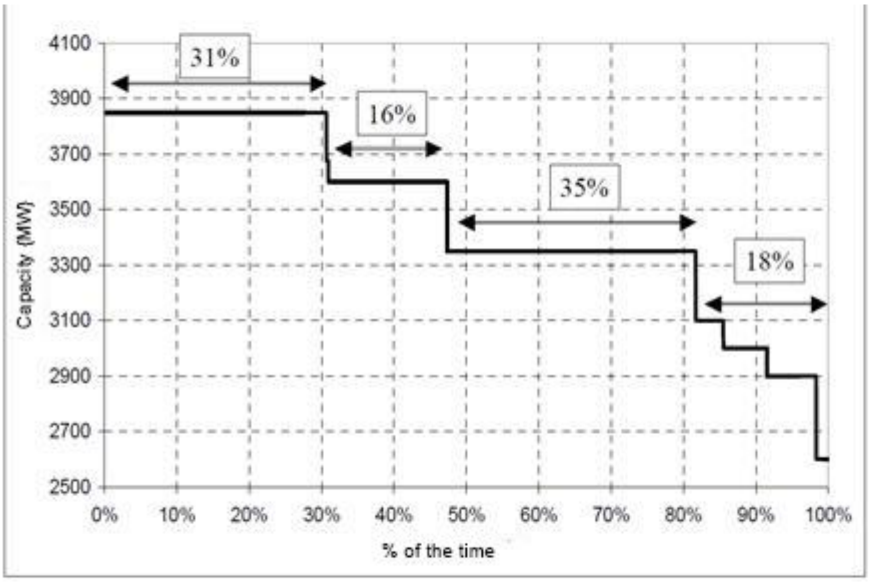
Source: Borggrefe and Neuhoff (2011)

and lower interconnection capacity…

[27] These estimates, however, are not related to the underlying variable. Mott MacDonald (2013) notes that the RMSE is only significant in relation to the average price of the underlying variable.

In addition, the uncertainty regarding wind predictions also means that network capacity must be reserved on interconnections in order to be able to adequately transport the electricity produced. To determine the securely available cross-border transport capacity, network calculations are made for various scenarios, including for situations which include the failure of a grid component, for example, a transformer or a line ("N-1" situations), and during maintenance. The transport capacity is set to the scenarios' lowest values for import and export capacity, respectively (ACM, 2015c).[28] TenneT (2005) states that the increasing variability of electricity flows is the most important reason for the limited increase of day-ahead interconnection capacity that is made available on the market. Figures 5 and 6 show the capacity available for import to the Netherlands from Belgium and Germany at peak hours for 2004 and 2014, respectively. In spite of an increase of approximately 700 MVA[29] in the physical capacity of cross-border connections with Germany and network expansions within Belgium, Germany and the Netherlands, which make more cross-border transactions possible, the available import capacity for electricity trading in 2014 amounted to 3100 MW or less in 24% of the cases (2004: 18%).

Figure 5: Available Dutch import capacity for transports from Belgium and Germany at peak hours on work days in 2004

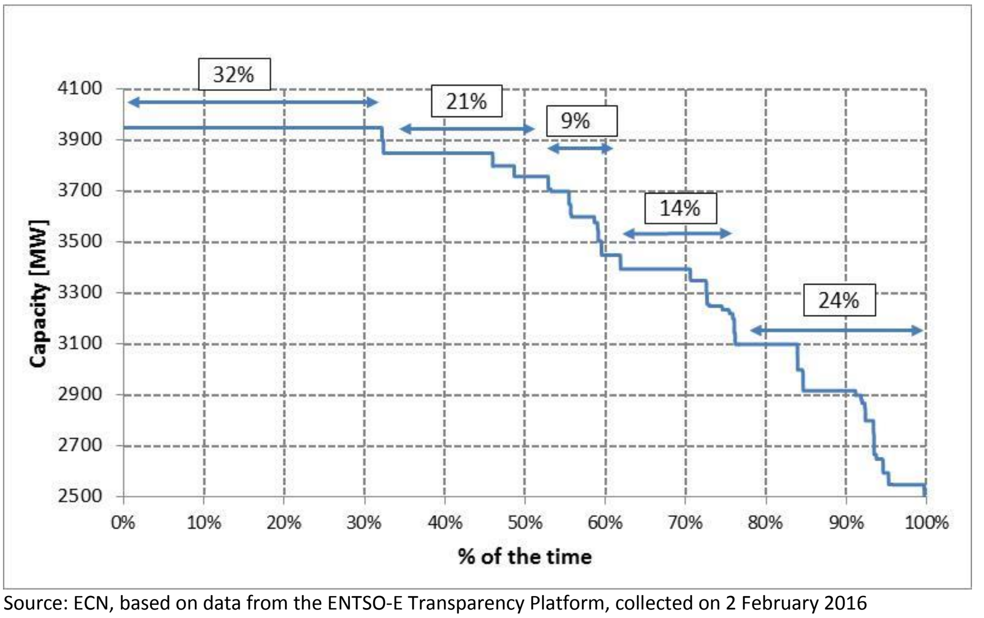


Source: TenneT (2005)

[28] Article 5.7.1.

[29] The total physical import capacity from Belgium and Germany in 2004 was 12,346 MVA, and in 2014 it was 13,036 MVA; see UCTE (2005) and ENTSO-E (2016), respectively.

Figure 6: Available Dutch import capacity for transports from Belgium and Germany at peak hours on work days in 2014



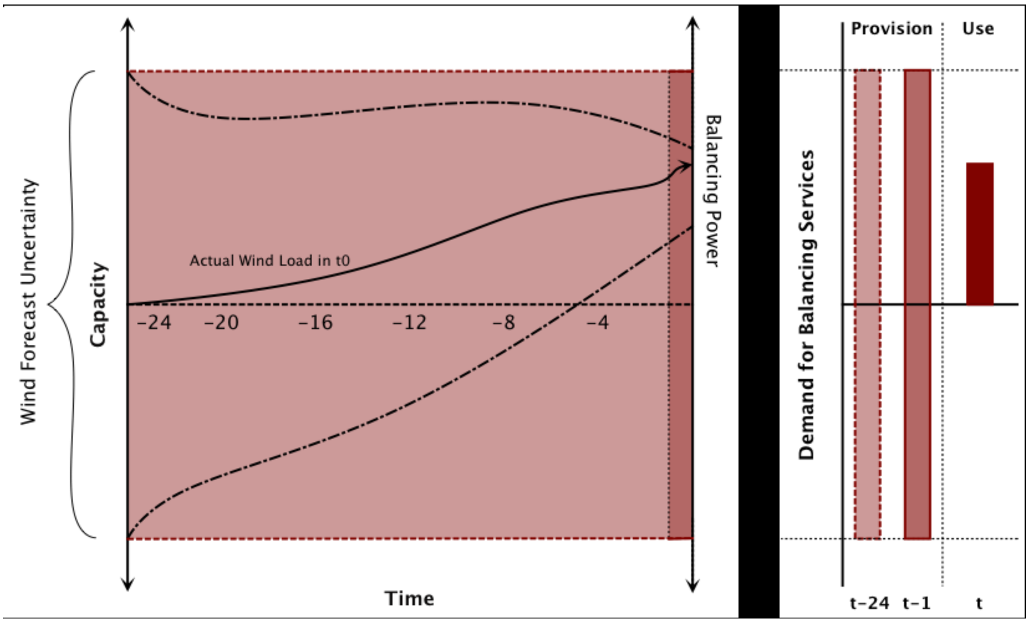
Source: ECN, based on data from the ENTSO-E Transparency Platform, collected on 2 February 2016

… demands a greater role for intra-day and balancing markets

The increase in imbalances and the decrease of available interconnection capacity for electricity trading can (in part) be counteracted by trading electricity closer to real time. Greater utilisation of short-term electricity markets (i.e., intra-day and balancing markets) also augments market liquidity through smaller bid-ask spreads. A shorter predication time results in a smaller prediction error and reduced demand for balancing.

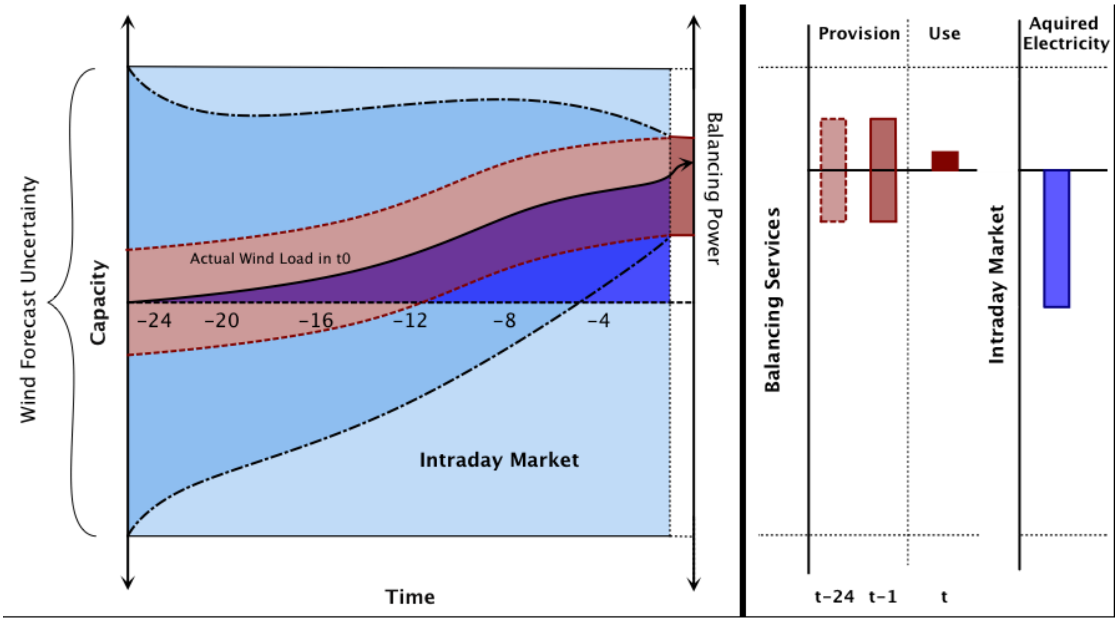
Figures 7 and 8 illustrate the added value of an intra-day market. Both figures show the unpredictability of wind forecasts starting from 24 hours before real time up until the moment of physical production. More is produced than expected, and this causes demand for an intra-day market and for balancing services to limit electricity surpluses. For that, the TSO must contract balancing services (‘provision by market participants’), in this case on a day-ahead basis, and utilise them. Figure 7 clearly shows that without an intra-day market, more balancing capacity must be contracted and utilised than in the situation with an intra-day market shown in Figure 8. In the latter figure, the surplus in the intra-day market is already reduced to such an extent that the residual need for the utilisation of balancing capacity is considerably smaller. As indicated above, this leads to cost savings, because in an intra-day market, further from physical provision, more flexibility supply is available at a lower cost than in a balancing market, close to physical provision. Holttinen (2005), among others, has shown this quantitatively. Holttinen has looked at the increase in net income from wind turbines in the Scandinavian market from trading on an intra-day market 6 to 12 hours before provision or 2 hours before provision, as opposed to on the day-ahead market (12-36 hours ahead). Due to a decrease in balancing costs, net incomes rise in the first case by 4% and in the second case by 8%.

Figure 7: Unpredictability of wind forecasts and the need for balancing in a situation without an intra-day market



Source: Borggrefe and Neuhoff (2011)

Figure 8: Unpredictability of wind forecasts and the need for balancing in a situation with an intra-day market



Source: Borggrefe and Neuhoff (2011)

Furthermore, a decrease in uncertainty about the actual production means that network calculations are needed for less diverse scenarios, reducing TSOs' need to reserve network capacity.

Current roles of intra-day and balancing markets are still limited however
The limited role of intra-day markets is evident from the limited traded volume of electricity on the intra-day market. In fact, the volume of intra-day trading in the Netherlands in 2013 was only 0.7 TWh in comparison to 47.2 TWh on the day-ahead market (APX) and 113.5 TWh on all organised markets (ACM, 2014).[30] The volume of intra-day trading as a fraction of the electricity demand in the Netherlands in 2014 was only 0.2%, in comparison to 1.0% in Belgium, 4.4% in the United Kingdom and 4.6% in Germany (ACER/CEER, 2015).[31] The scale of the balancing markets is also limited; the turnover from these markets represents only 2-3% of the total turnover from wholesale markets (Mott MacDonald, 2013).

The question is why the scale of intra-day and balancing markets is still so limited, not only in the Netherlands, with its limited share of intermittent renewable energy, but also in other countries in the Northwest European market, such as Germany, which has a much greater share and with which the Netherlands has increasingly closer ties. Often, a list of widely varying reasons for this is proffered, such as a lack of market liquidity, the complexity of the balancing markets etcetera. At a more fundamental level, the cause must be sought in certain market design choices which have been made in conjunction with the liberalisation of the electricity sector. These choices will be examined in greater depth in Section 4 on the basis of three central themes for market design from the US, while the European and national interpretations of these themes will be discussed in Section 5.

[30] Table 3.
[31] Table 16.

4. Lessons from the United States for complete electricity markets

The functioning of electricity markets can be assessed by the extent to which the market design approximates competitive and complete markets (Wilson, 2002; O'Neill et al. 2006; Helman et al. 2008; Smeers, 2008). When striving for competitive markets, the main focus is on measures designed to restrict the exercise of market power in order to preserve incentives for efficient investment and operational decisions. The term completeness here refers to system optimisation incentives, which are used in each consecutive time period to achieve market efficiency (Wilson, 2002). Market efficiency can be achieved if an equilibrium price exists for each asset/product in every possible situation. Due to the enormous number of possible situations, the electricity market, and with it the electricity price, is extremely differentiated with regard to time and space and, therefore, comprises a great number of different 'products'. This is related to various physical properties of electricity systems, including:

- The absence of significant storage capacity, which means that electricity generation and consumption must be instantaneously in balance and that the electricity system is vulnerable to instability;
- The limited controllability of electricity transport in alternating current networks (Kirchhoff's circuit laws), which results in various network restrictions; and
- The presence of operational limitations to network infrastructure (thermal, stability and voltage limitations) and generation units (required start-up time and limitations to ramping and operating at part load).

These physical properties have two important consequences for the market design (Smeers, 2008). Firstly, they confine the spot market to only being able to exist in real time. Given that electricity cannot be stored (to any significant extent), this is, in fact, the only time at which electricity can effectively flow from producer to consumer. Forward markets, such as day-ahead and intra-day markets, trade products derived from the products that are traded in real time on the spot market (Mott MacDonald, 2013). Therefore, forward prices are also linked to the spot prices, in spite of the fact that the real-time market is, in essence, a residual market (Smeers, 2008). Forward markets are used to decide which power plants must be utilised. The potential production levels are restricted at a later time due to the start-up costs and ramping limitations of power plants (Wilson, 2002). Consequently, there are inter-temporal effects which market organisation policy-makers must take into account by designing markets for different time periods.

Secondly, if one of the aforementioned operational limitations is binding at a specific point in time, this means that the value of electricity is dependent on location. Since electricity follows the path of least resistance (Kirchhoff's circuit laws), electricity trading between two parties results in flows along various paths. This influences the physical space for other flows, in other words, for other trading transactions ('network externalities'). Because of this, trading transactions are mutually interdependent. Consequently, the locational effects of market transactions should be taken into account in the market design.

In the market design in the US, participants have taken these time- and location-specific dimensions of electricity into careful consideration.[32] The two most important economic aspects of the market design are discussed below (Wilson, 2002):

a) Optimisation of markets for energy, transmission and reserves by an ISO,[33] taking into account inter-temporal costs and limitations, such as start-up, ramping and potential energy in hydroelectric reservoirs. The optimisation of these markets occurs simultaneously by means of an integrated process. For this, a so-called smart market is utilised. A smart market is a market in which a computer is used for security constrained economic dispatch (SCED); in other words, for the balancing of supply and demand and the determination of marginal prices (Smeers, 2008). Pricing and settlement are based on system-wide opportunity costs which can be inferred from the shadow prices for the balancing of supply and demand in real time and from limitations in transmission capacity. Markets are organised as sealed-bid, multiple-unit auctions in which market clearing occurs with uniform prices. In other words, bids from buyers and sellers are not known by others, and bids contain not only prices and quantities but also start-up costs, 'no-load' costs and a number of physical characteristics, including response speed. Furthermore, with uniform pricing, market clearing for all generation units takes place at the highest marginal bid.

For spatial arbitrage, the ISO uses an Optimal Power Flow (OPF) tool, which is also used to set locational marginal prices, or LMPs. Producers receive a bundled price (LMP) for the short-term costs of energy, congestion and network losses.[34] In addition, they receive separate compensation for costs related to purchasing or selling, such as the cost of starting up a power plant, if the LMP does not adequately guarantee revenue sufficiency. Consumers pay the load-weighted, average LMP for a zone or, in other words, a zonal price (Helman *et al.* 2008). The SCED guarantees physical feasibility and coordination between energy and derivative products, such as transmission and reserves. Generally speaking, this optimisation occurs on a day-ahead basis and again, subsequently on an intra-day (hours ahead) basis and in real time.

b) Based on bids, the ISO determines which power plants will be utilised when, including the accompanying production levels and duration of deployment. Unit commitment is integrated into the day-ahead market, while for real-time markets, a programme is implemented before the auction to predict which units must be committed or decommitted. Subsequently, at the auction itself, it is only the dispatch of the committed units that is adjusted every 5-15 minutes (Helman et al. 2008). Central unit commitment is also deployed by power pools. However, these power pools do not employ nodal pricing, and they operate in a regulated environment as opposed to in a market environment (Stoft, 2002). In many ways, the ISO resembles a 'single buyer', although participants can also bilaterally commit power plants. In that case, they receive the LMP from the auction.

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[32] In the US, there are two types of markets: markets based on bilateral contracts between electricity companies and producers and markets in which Independent System Operators (ISOs) organise regional auctions and allocate transmission capacity (Helman et al. (2008)). For the remainder of this discussion, we will take the latter type as our point of reference.

[33] ISOs manage the network, and ownership lies with the regional transmission owners (RTOs). In Europe, both ownership and management are in the hands of the TSOs, and these activities are subsumed in various departments within the TSOs.

[34] As a result, this price excludes the long-term network costs for transport from a producer's location to a reference location.

The following three central themes emerge from the description above (Wilson, 2002; O'Neill et al. 2006; Smeers, 2008; Borggreve & Neuhoff, 2011):

a) Consistency between electricity markets for different time horizons
b) Simultaneous alignment of energy provision and reserve capacity
c) Simultaneous alignment of energy trading and congestion management

Each central theme has important and universal implications for how electricity markets handle flexibility. As a result, the themes are not only relevant for the specific situation in the US but also within the European context.

a) Consistency between electricity markets for different time horizons

The different electricity markets for electricity production (and demand) must be consistent with one another in time. For each forward market, it must be possible for every buyer or seller to adjust its financial position in the next market by re-buying or re-selling either a portion of its position or its entire position. The final adjustment takes place on the physical, real-time balancing market. Based on this, prices for the provision of the actual product can be calculated (O'Neill et al. 2006). The term "multi-settlement" system is often used in market design terminology. This refers to a system with several settlement points.

… **leads to a more uniform, time-related flexibility demand and lower flexibility costs**

A multi-settlement system prevents the day-ahead scheme from differing significantly with the intra-day and real-time schemes and facilitates gradual adjustments in the direction of the real-time/physical system conditions as opposed to large and fundamental corrections at later times. This is very important for a future which holds greater weather-dependent electricity production in which weather and, with it, production forecasts improve significantly throughout the day. With a multi-settlement system, market participants can make corrections in their portfolios for the purpose of counteracting deficits or surpluses, and the need for balancing by the TSO (as the entity with final responsibility for the system) decreases. This results in an increased demand for flexibility in portfolio management and a decreased demand for flexibility in balancing, and hence a more efficient distribution of the flexibility demand over time, since greater flexibility supply at a lower cost is available at time scales further away from real time. After all, the required reaction time and the stability of the flexibility provision in the former situation are less critical for the system than they are in the latter situation. Conversely, it is also true that the closer one gets to physical delivery, the fewer available power plants there are that can adjust their production to the needs of the system and the higher the costs of flexibility become.

b) Simultaneous alignment of energy provision and reserve capacity

Producer services, such as energy, balancing and reserve, act in part as complements and in part as substitutes. On the one hand, energy and balancing are complementary services, given that energy provision is a pre-condition for the supply of downward regulating capacity and that operating at part load is a pre-condition for the provision of upward regulating capacity. On the other hand, energy and balancing are substitutional, since the provision of balancing (in other words, energy) results in the same generation unit being unable to supply as much energy to forward markets as it otherwise would. In this way, the provision of reserve capacity by power plants limits the utilisation of production capacity for energy provision on day-ahead and intra-day markets (O'Neill et al. 2006). It is important that these complementary and substitutional operational characteristics of a generation unit (and potentially also of demand and storage) are adequately reflected in the market design.

… increases access to the flexibility supply of production, demand and storage
The importance of coordinating the supply of energy with the supply of reserve capacity increases in a future with greater weather-dependent production. Since the uncertainty regarding wind forecasts decreases after the closing of the day-ahead market, the need for reserve capacity may also decrease. Consequently, this reserve capacity can be diverted to energy provision on the intra-day market. Conversely, if the need for energy on the intra-day market decreases, suppliers must be able to offer their flexibility on the balancing market (Borggrefe and Neuhoff, 2011). In order to be able to take the greatest advantage of the available flexible capacity, decisions related to the utilisation of flexible capacity (including demand response) for day-ahead and intra-day energy trading, on the one hand, and for the reservation of capacity for real-time balancing, on the other hand, must be coordinated as optimally as possible. In the past, this was less important, because the demand for balancing capacity was predictable on a weekly (week days versus weekend days) and on a daily (peak and off-peak hours) basis. However, in the (near) future, with large shares of weather-dependent electricity production in the mix, the residual demand profile (demand minus wind production) and, with it, the demand for flexible balancing capacity will vary much more at the aforementioned time scales and on an hourly basis. This makes it necessary to implement a market design that stimulates simultaneous decisions regarding the provision of energy and reserve capacity.

c) Simultaneous alignment of energy trading and congestion management
In addition to time limitations, location-specific limitations related to the transport of electricity are also important for the market design. As mentioned above, each trading transaction influences the physical space for other trading transactions (not, by definition, a negative influence: a transaction can also free up space for additional transactions by causing counterflows). Therefore, alignment between energy trading by market participants and congestion management by TSOs is essential.

If energy trading by market participants and congestion management by TSOs does not occur simultaneously but sequentially, TSOs, due to physical network limitations (thermal, voltage or stability limitations), must regularly correct market transactions with out-of-market actions, such as re-dispatch, and they must do this after the fact. With re-dispatch, a transaction which is beneficial from a market perspective, is (partially) undone by regulating downward on the surplus-side of the network limitation and by regulating upward on the side with a deficit. In this way, the operational network security is guaranteed.

Energy trading by market participants and congestion management by TSOs can also occur simultaneously by considering the benefits to trading brought about by the transactions, on the one hand, and the occupation of the network capacity, on the other hand. To do this, the network limitations must be reflected in the network representation of the market and be assigned a price. Simultaneous alignment of energy trading and congestion management is important for all markets: day-ahead, intra-day and balancing markets, although its importance is greatest for markets with a short time horizon. After all, those markets have the least time available for TSOs to take corrective actions in order to have the markets dovetail with the physical reality.

… reduces the demand for flexibility and increases the access to flexibility supply from abroad

If energy transactions are corrected after the fact by means of congestion management, flexibility must be diverted (power plants, demand response etc.) for this purpose. By allowing energy trading and congestion management to occur simultaneously, suboptimal transactions on the electricity markets can be prevented and will not have to be corrected afterwards by utilising flexibility for upward and downward regulation.

When making (cross-border) network capacity available for different time horizons, the opportunity costs associated with the utilisation of network capacity at other times, i.e., the lost revenue from trading at other moments, should be taken into account. If network capacity is reserved, for example, in its entirety for the day-ahead market, market participants can trade this capacity on the day-ahead market and make a profit, but revenue from the intra-day and balancing markets will be lost. If the opportunity costs of network capacity are adequately taken into account, access to foreign flexibility supply will improve on short-term time scales at the expense of access to foreign flexibility supply on longer-term time scales. For a future which holds a great deal more weather-dependent electricity production, greater flexibility supply in the shorter-term is of eminent importance.

Furthermore, new, more accurate information throughout the day reduces the uncertainty for TSOs about the development of electricity flows over interconnectors, so that TSOs can make more network capacity available for cross-border, intra-day electricity trading and balancing actions. As a result of this, the access to available flexibility from foreign countries increases. This, in turn, increases the magnitude of electricity markets and, with that, the market efficiency, as well as diminishing the opportunity to exercise market power.

5. Important market design parameters, barriers and policy options for the Netherlands and the EU

The follow-up question is how the Netherlands and the other EU countries score in the three themes that are essential for a complete market. For an in-depth discussion of simultaneous alignment of energy trading and congestion management, please refer to the important paper written by Smeers (2008). For both of the other themes, it is useful to look in greater detail at important underlying factors or design parameters related to markets. While doing so, the focus lies on a limited number of parameters or aspects for which adjustments can contribute to a better market design in the context of the increasing need for flexibility. There are many more design parameters imaginable (for balancing markets, for example, see Van der Veen, 2012), but some parameters are more closely related to the technical design or are less essential for this study and, therefore, fall outside its scope.

5.1 Consistency between electricity markets for different time horizons

Without consistent pricing, artificial arbitrage opportunities arise which do not correspond with the economic and physical reality and, as a result, are undesirable from a system perspective. Consistent markets can be designed in a variety of ways, with simultaneous and sequential optimisation of markets by one or more participants, respectively.

In the US, simultaneous optimisation of markets for energy, transmission and reserves takes place by means of a centralised economic dispatch process performed by an ISO. Generally speaking, the ISO carries out this optimisation on a day-ahead basis and subsequently on an intra-day basis ('hours ahead') and again in real time. The ISO calculates prices based on system-wide opportunity costs with a bundled price for energy and the short-term costs of network and reserve capacity.

In the EU, sequential optimisation is used. PXs with inputs from TSOs first optimise markets for energy and cross-border transmission by means of implicit auctions, after which TSOs resolve any network limitations at the national level. Reserve capacity is contracted by TSOs in a separate process. This results in bundled prices for energy and the short-term costs of network capacity for national borders within the EU and different prices for energy and the short-term costs of network and reserve capacity at the national level.

The fact that day-ahead, intra-day and real-time markets are interrelated from an economic prospective has therefore not been adequately taken into account in the formulation of the EU target models (Smeers, 2008). This applies both to energy products as well as to the derived products for reserve and network capacity.

Energy products for these markets are traded by various participants on trading platforms with varying designs. Day-ahead trade usually occurs at fixed times (hours) on the power exchanges. Conversely, the target model for intra-day trading assumes continuous trading by power exchanges whereby energy trading occurs continually. In the target model for balancing, it appears that there is extremely limited space for market participants to make adjustments to their positions[35], and no role is provided for power exchanges, only for TSOs.

Network capacity products are also designed differently in consecutive markets. On the day-ahead market, the power exchanges auction energy at the same time as network capacity by means of an implicit auction. In the event of a shortage of cross-border network capacity, the energy price is adapted to the situation. In addition, network capacity is allocated to zones using the flow-based method (see Section 2). On the intra-day market, the available cross-border network capacity is allocated on a first-come, first-served basis at a price of nought. The intention, in the long term, is that the network capacity is priced in an implicit auction and by means of a flow-based capacity calculation. It is true that for both the day-ahead as well as the intra-day markets congestion within bidding zones, or countries, is resolved after the fact by TSOs in a separate market by means of re-dispatching. On the real-time energy market, network limitations will be expressed directly in the price, since balancing offers insufficient time to attribute a price for network capacity in a separate market after the fact. As opposed to the zonal network representation in day-ahead and intra-day markets, the real-time market will have a nodal network representation.

Markets for reserve capacity products are a separate matter. Generally speaking, the TSO has already contracted reserve capacity ample time before day-ahead trading, and contracted participants must be available throughout the entire contracted period. Although the need for reserve capacity is smaller on a day-ahead basis, and even smaller on an intra-day basis, markets for reserving more or less reserve capacity on day-ahead and intra-day bases are lacking. On a real-time basis, a market for reserve capacity is unnecessary: all of the reserve capacity needed is already committed. The only question is which flexible capacity the TSO will dispatch.

When designing consistent energy, network capacity and reserve capacity markets in time, the following specific aspects play a role:[36]

- Granularity of products on DA, ID and real-time markets
- Pricing mechanism or rule: marginal or pay-as-bid prices
- Activation strategy: proactive versus reactive balancing by the TSO
- Cross-border network capacity for DA, ID and real-time markets

For each of these parameters or aspects, the barrier will be discussed first, followed by the possible adjustment(s).

Barrier: Unequal granularity of products on DA, ID and real-time markets
The product time-resolution differs for energy products on the day-ahead market (1 hour), the intra-day markets (usually 1 hour; in Germany 15-minute products have also recently been introduced) and the balancing markets (15 minutes in Belgium, Germany and the

[35] In light of statements in ACER (2015a) to the effect that the gate closure time for balancing markets may not come before the gate closure time of the intra-day market and that it is possible that market participants may only be permitted to keep their portfolios balanced and may not contribute to the recovery of the overall system balance. For further elaboration on these points, see the section below related to the adoption of balancing markets with reactive TSO activation strategies in (Northwest) Europe and the row of the table in Section 6 that is related to this topic.

[36] Harmonisation of the gate closure times of the day-ahead, intra-day and balancing markets is already covered in and part of the CACM Network Code (EC, 2015a; DA: Article 47, ID: Article 59) and the draft EB Network Code (ACER, 2015a; balancing energy: Article 35; balancing capacity: Article 12(4)).

Netherlands; see ENTSO-E, 2015). Given that the price variability is higher for 15-minute products than for one-hour products, 15-minute products better reflect the value of flexibility. This means that – ceteris paribus – market participants will offer more flexibility in balancing and intra-day markets than they will in the day-ahead market. This is undesirable given that it can lead to significant adjustments in trading positions in the final hours before real-time as opposed to more gradual adjustments spread over the entire time period from before day-ahead through real-time.

The greater need for flexibility results from the increase in weather-dependent electricity production and, with it, the variability in the electricity system, so that the slope of the residual demand curve also becomes much steeper at various time periods on a day-ahead basis. This means that participants with hourly offerings on the day-ahead market will find it increasingly difficult to follow the demand curve at those moments, which will result in greater imbalance which can only be resolved with more expensive flexibility in intra-day trading or on the balancing market (since it is closer to real time).

Possible solution: Shortening the time resolution for day-ahead market products to 15 minutes

One solution is to not only settle balancing and intra-day products every 15 minutes but to do the same for day-ahead products (Neuhoff *et al.* 2015). One disadvantage of this is that due to operational limitations, such as ramping, conventional power plants are often insufficiently flexible to adjust the quantity of energy to be supplied for such short time periods to the development of the energy prices (and with that to the need for flexibility). This lack of *load-following capability* leads to imbalance costs, unless the relevant power plant is part of a portfolio with more flexible sources which can compensate for the imbalance. Apart from that, adjustments within a portfolio also come at a cost. In that case, higher imbalance costs are replaced by higher costs for portfolio management (although the costs associated with the latter are probably lower, since portfolio management occurs earlier than system balancing). To prevent higher imbalance costs, conventional power plants could offer their production by means of other bidding formats, such as block bids for groups of hours. This topic is discussed further in Section 5.2.

Barrier: Different pricing rules in different energy markets hinder European harmonisation

With marginal pricing, all energy is traded at the marginal price where supply meets demand. Given the fact that the marginal price applies to all participants, it is also referred to as the uniform price. With pay-as-bid pricing, each bid that is accepted is paid at the specific bid price. In this case, the least expensive supply and the most expensive demand bids are selected until the supply is equal to the demand for the relevant product.

The bidding strategy of the market participants differs per pricing rule. In the case of marginal pricing, the best bidding strategy is to bid the variable costs. If the market price rises above the variable costs, the market participant can earn back a portion of its fixed costs. In the case of pay-as-bid pricing, the market participant must earn back the fixed costs by means of an increase that is included in its bid price. At the same time, the market participant must not price itself out of the market by setting too high a price.

From the standpoint of economic theory, marginal pricing is preferred for energy products, primarily because with pay-as-bid prices there is a risk of inefficient production choices; it is not the units with the lowest costs but those with the lowest bids that are selected (Cramton en Stoft, 2007; Van der Veen, 2012; Neuhoff et al. 2015).[37] Current practices in the Netherlands and various neighbouring Member States, however, do not always assume marginal pricing. In fact, prices for bilateral (including OTC) energy trading vary, by definition, per transaction and are therefore pay-as-bid. This also applies to the Dutch intra-day market and the joint intra-day markets with Belgium and Norway in which market participants – as was noted in Section 2 – trade electricity on a continuous basis. In Germany, balancing energy is also settled with pay-as-bid pricing rules. Conversely, energy in day-ahead and balancing markets (energy for regulating and reserve capacity) in the Netherlands is settled on the basis of marginal prices.

In contrast with energy products, it appears that for capacity products a clear economic argument for either marginal or pay-as-bid prices is lacking. In the Netherlands, capacity products in the reserve market (FCR, FRR) are settled on a pay-as-bid basis. With regard to FCR, neighbouring countries, such as Germany, Belgium and the United Kingdom, also settle on a pay-as-bid basis, while West Denmark and Norway work with marginal prices (ENTSO-E, 2015). In the case of FRR, the same distinction between countries holds, with the exception of West Denmark, which in this case also settles on a pay-as-bid basis (ENTSO-E, 2015). For reserve capacity products, preference is given to pay-as-bid pricing in a majority of countries, which suggests that this form of pricing leads to lower reserve capacity costs (Van der Veen, 2012).

Network capacity is traded primarily on cross-border forward and day-ahead markets, is traded to a limited extent on cross-border intra-day markets and is not yet traded on balancing markets. As in the case of reserve capacity, a clear direction is still lacking. Network capacity on borders between bidding zones in day-ahead markets is traded on the basis of short-term marginal prices which reflect congestion and network losses. While the trade in intra-day network capacity on the border with Germany occurs at pay-as-bid prices. In the latter case, a first-come, first-served capacity allocation method applies, whereby sellers have the opportunity to trade at a price above the marginal costs and therefore at pay-as-bid.

In other words, there is a lack of harmonisation between countries with regard to pricing rules for both energy and capacity products. This is one of the important factors which hinders access to foreign flexibility for different time scales.

Possible solution: Stimulation of cross-border trade through marginal pricing of all energy products
Developments are already being made toward this solution approach. The price coupling algorithm of the day-ahead market assumes marginal pricing of energy and network capacity and is already applied throughout a large part of Europe. The extension of this to the remaining European countries is anticipated in coming years. Marginal pricing of energy is

[37] In addition, the use of pay-as-bid pricing leads to faulty incentives for market participants that are both BRPs and BSPs. With pay-as-bid pricing, the reward for the provision of balancing energy can in fact differ from the price derived from imbalance settlement. Since the imbalance price is usually the weighted average of the bid prices from selected bids, with pay-as-bid, half of the bids are lower than the imbalance price and the other half of the bids are higher. If the imbalance price is lower than the bid price, market participants that are both BRPs as well as BSPs have an incentive to not supply the desired balancing energy. While in the opposite case, they have an incentive to not commit flexibility but to instead keep it for portfolio management (Van der Veen, 2012).

foreseen for the energy balancing market after entry into force of the anticipated European Regulation on Electricity Balancing (ACER, 2015a).[38] Marginal pricing of energy in the intra-day market also appears to be part of the target model in an indirect way. In fact, before the middle of August 2017, TSOs must formulate a proposal for intra-day pricing of network capacity, and in many cases, they will have to calculate this capacity using the flow-based method, given that flow-based capacity allocation is the standard approach for both day-ahead and intra-day markets (EC, 2015a).[39] With the flow-based method, a transaction (explicitly) influences various critical network elements, thereby competing with other transactions for these elements. As a result, simultaneous optimisation of a set of transactions also appears to be unavoidable for the intra-day market (Neuhoff en Boyd, 2011), and, with it, the introduction of non-continuous, implicit auctions for the intra-day market, as these are also used for the day-ahead market. Just as occurs on the day-ahead market, intra-day products can therefore also be settled on the basis of marginal prices. However, this contradicts the idea of organising the intra-day market according to the financial model of continuous trading (see Smeers, 2008), which is also a part of the CACM Regulation (EC, 2015a). The adoption of marginal pricing on intra-day markets appears to require a significant change to the CACM Regulation, which could obstruct a change in pricing. At the same time, it is plausible that energy products on day-ahead and balancing markets will be priced marginally in the foreseeable future.

Barrier: Costs of adjustments using proactive TSO activation strategy higher than necessary
Within many (Northwest) European countries, the opportunities for adjusting previously held energy positions are often limited. Market participants must often follow their programmes strictly and may not passively participate in regulation.

In this respect, the distinction between proactive and reactive activation strategies is important (TenneT, 2013b; Ecogrid, 2013). With a proactive activation strategy, the TSO attempts to prevent imbalance as much as possible ('preventive'); here markets close a minimum of 1 hour before provision. The TSO activates bids for real time based on the anticipated system imbalance (Van der Veen, 2012). In doing this, the TSO usually uses a relatively large proportion of slow replacement reserves with a longer activation time. Imbalance is settled with dual imbalance prices, in other words, prices that depend on the direction of the imbalance. This results in prices for positive imbalance being lower than prices for negative imbalance and Balance Responsible Parties running a great financial risk in the event of a faulty action (Ecogrid, 2013). In this scenario, the TSO prevents network users from resolving part of their imbalance in real time, and market incentives are eliminated. Examples of balancing markets with this activation strategy can be found in Germany, France and, to a lesser extent, in the Scandinavian countries.

With a reactive activation strategy, the TSO only activates bids in reaction to the momentary system imbalance ('curative'). With this strategy, the TSO gives market participants a great deal of flexibility to adjust energy programmes right up until close to real time in order to limit, as much as possible, the need for the TSOs to provide balancing. Some TSOs publish information about the system balance on a real-time basis in order to stimulate market participants to also react in real time to reduce the system imbalance. Individual generation units may deviate from scheduled production or consumption on the condition that the

[38] Article 42.
[39] Article 20.

portfolios in which they are included are still in balance. In addition, market participants may deviate from their portfolios on the condition that they reduce the system imbalance. TSOs with a reactive activation strategy use a relatively large proportion of fast reserves (mainly automatic FRR) with a shorter activation time. Imbalance is usually settled with single imbalance prices which are independent of the direction of the imbalance. Balancing markets with this activation strategy can be found in Belgium and the Netherlands.

So, there are important differences between balancing markets with a proactive and those with a reactive TSO activation strategy. With a proactive activation strategy, part of the available flexibility supply is not taken into account by TSOs, and opportunities for adjustments of previous energy positions are more limited than with a reactive activation strategy. In the former case, adjustments are also often discouraged by means of preventive TSO actions and (implicit) penalties for imbalance, for example by dual imbalance prices, which results in imbalance prices not accurately reflecting costs. On the other hand, a proactive activation strategy is sometimes considered necessary, for example if the TSO bears the responsibility for balancing renewable energy or if there are different portfolios for production and consumption (Van der Veen, 2012). The utilisation of a proactive activation strategy by TSOs can also lead to more stable activation pathways (Van der Veen, 2012) and to the use of fewer valuable reserves.

Possible solution: Adoption of balancing markets with reactive TSO activation strategies in (Northwest) Europe
As mentioned above, TenneT employs a reactive activation strategy which allows market participants to easily update previously held energy positions within the Netherlands. These energy positions are reported by BRPs in energy programmes, and updating occurs by means of intra-day trading (via PX, OTC and bilaterally) and by passively participating in regulation by reacting to the delta imbalance signal. Programmes can even be adjusted up until 10:00 the following day (‘ex-post nomination’). In comparison with other EU countries, the Dutch balancing market is relatively flexible.

In order to maintain the current level of flexibility in regional and European balancing markets, it is important that European regulations, such as the NC EB, enable this. The current draft, including ACER proposals, strives to give market participants a great deal of space and suggests that TSOs will be able to partially follow a reactive activation strategy.

This way, activation of bids by TSOs before the gate closure times of balancing energy markets is not permitted, except in the event of an alert or emergency in the system, as this safeguards fair competition between BSPs (ACER, 2015a, Art. 43). Balancing energy must be contracted as close to real time as possible, and the gate closure time for balancing energy must lie after the intra-day market to the greatest extent possible (ACER, 2015a, Art. 35).

Furthermore, not only may contracted suppliers of reserve capacity place bids for balancing energy, but all BSPs that fulfil the pre-qualification requirements are also be permitted to do so (ACER 2015a, Art. 27 (6)).

In addition, the imbalance settlement must prompt BRPs to strive for a balanced position or to help the system to recover the balance (ACER 2015a, Art. 55 (1c)). A single imbalance price is provided which is independent of the direction of the imbalance. Participants that profit from new support measures for renewable electricity production are also balancing-responsible as of 1 January 2016, unless no liquid intra-day market exists (EC, 2014).

However, the proposed design of regional and European balancing markets is a step backward with regard to at least two points. Firstly, the gate closure time of the balancing energy market is earlier and potentially closer to the gate closure time of the intra-day market. As a result of this, market participants are no longer able to supply balancing energy in real time. Also, ex-post nomination is not considered by ACER to be worthwhile (ACER, 2015a, Annex I), so that market participants must conclude administrative processes before the market gate closure time and are able to trade for a shorter period. Secondly, there is the question of whether market participants may still be permitted to contribute to the recovery of the system imbalance, since Article 55 of ACER (2015a) includes the possibility of requiring market participants to pursue a balanced portfolio exclusively, leaving the TSOs a greater role in system balancing. In other words, when it comes to imbalance settlement, incentives to stimulate an active role for market participants may not be provided. EZ, TenneT and ACM certainly have a role to play in convincing foreign and European stakeholders that in an efficient balancing market, market participants must be able to contribute to the recovery of the system balance and must likewise be able to supply balancing energy in real time.

Barrier: Shortage of cross-border network capacity on intra-day and real-time bases limits possibilities for cross-border hedging
In Europe, only the residual network capacity after day-ahead trading is available for cross-border intra-day trading and balancing actions, and no cross-border network capacity for intra-day and balancing is reserved in advance. Therefore, network capacity must also be nominated on a day-ahead basis and is considered firm, or definitive, after nomination;[40] in other words, the utilisation of the network capacity is fixed after the close of day-ahead trading. As a result, the available network capacity for the exchange of energy for intra-day and balancing markets in the same direction as the day-ahead trading is largely limited to the network capacity that remains after day-ahead trading.[41] In addition to this, network capacity may become available as a result of updates to network capacity calculations due to the decrease in network planning uncertainty faced by TSOs over time. However, after day-ahead calculations are made, TSOs rarely perform updates to capacity calculations for their networks (ACER/CEER, 2015). So, in many cases, it is very unclear whether or not there will be cross-border network capacity available for IDM and BM. This results in access to short-term, foreign flexibility being extremely limited.

Possible solution: Dynamic allocation method for cross-border network capacity
When a dynamic allocation mechanism is implemented, the expected values of the cross-border network capacity in markets for different time horizons (Poyry, 2014; Thema, 2015) are compared with one another, and the network capacity is allocated over the various sub-markets in such a way that maximum social welfare is achieved.[42] ENTSO-E (2014b) refers to

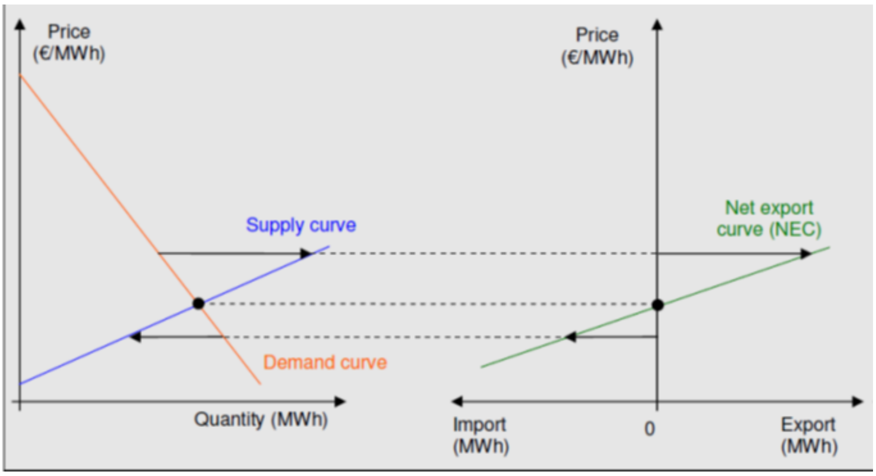
[40] With the exception of situations of force majeure.
[41] Otherwise, participants can trade without any problems in the direction opposite the flow direction which emerges from the DA trade.
[42] There are a number of possible models for dynamic allocation of cross-border network capacity. ENTSO-E (2014b) proposes three different models which vary depending on the extent to which they employ predictions or actual balancing capacity and day-ahead prices. In some of the models, TSOs are responsible for dynamic allocation of cross-border network capacity,

such a mechanism in the context of the cross-border balancing market. Using this mechanism, the market value for the exchange of a balancing product, such as reserve capacity, is compared with the market value for exchange of energy on the day-ahead market. Optimal allocation of cross-border network capacity means that the marginal value of the exchange of balancing services is equal to the marginal value of the exchange of energy in the day-ahead market. The application of a dynamic allocation mechanism can be expanded to the intra-day market (Poyry, 2014).

Instead of the current practise of estimating the yields of cross-border trading on the intra-day market at the closing of the day-ahead market, energy options can be used. An energy option provides the choice between trading energy now or at a later time. As a result, market participants have more opportunities to react to changing system conditions, such as the availability of wind energy. Given the bundled sale of energy and network capacity in an implicit auction, transmission rights are also part of the option. Consequently, not all transmission rights will be definitively allocated in the day-ahead market, but some of them will be assigned an option quality and will be allocated at a later time.

The effects of energy options can be illustrated using net export curves (NECs), which are used for day-ahead market coupling with implicit auctions. A net export curve is nothing more than the difference between a country's supply and demand. If the difference is positive, there is net export, and if the difference is negative, then there is net import (see Figure 9).

Figure 9: Net export curve



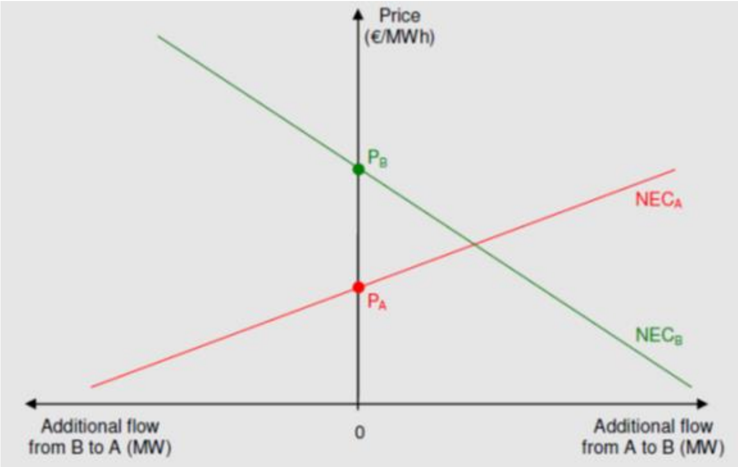
Source: ERGEG (2009)

An NEC can be constructed for a country for any unit of time, for example one hour. The NEC shows the market price for each additional MWh that is traded with a foreign party. By using NECs, the prices that are established on two markets in light of the available cross-border network capacity can be shown, as can the magnitude of the resulting trade (see Figure 10).

and in other models, this responsibility lies with the power exchanges and the market coupling operators. See Thema (2015) for a more in-depth discussion of this topic.

If the NECs also include energy options with their accompanying prices, the (opportunity) value of cross-border network capacity in the day-ahead algorithm becomes clear.[43]

Figure 10: Net export curves of two markets / countries



Source: ERGEG (2009)

In the US, these types of energy options already exist. There, they are called *virtual bids and offers* (O'Neill et al. 2006; Helman et al. 2008). The term virtual bid is used because these bids are not necessarily supported by physical assets or actual demand. A seller must buy back virtual supply bids (which were accepted at the DA price) at the real-time price, while a buyer must re-sell virtual demand (which was accepted at the DA price) at the real-time price. With this, market participants can apply price arbitrage between the DA and the RT markets, which leads to price convergence between both markets. It also leads to an increase in the liquidity of DA markets. Furthermore, the settlement of FTRs can be shifted from the day-ahead market to the real-time market by assuming an opposite position on the day-ahead market and by buying back this position on the real-time market.

However, additional flexibility for market participants to adjust their positions brings with it greater uncertainty for SOs about the physical realisation of the day-ahead programme in real-time.[44] First and foremost, virtual bids mean greater uncertainty about the extent to which supply and demand that are settled in the day-ahead market are physically adequate to meet the supply and demand in real time. This, in turn, leads to greater uncertainty about which generation units will be utilised the following day at which locations and, with that, greater uncertainty about the resulting electricity flows. In order to limit this uncertainty, ISOs in the US have implemented additional reliability unit commitment after the closing of the day-ahead market. In other words, an ISO removes accepted virtual supply bids from the results of the day-ahead auction and compares its own prediction of the load for the following day with the demand as settled in the day-ahead market. If the prediction of the load is greater than the demand, then the ISO reserves additional power plants.

[43] Liquid markets for energy options are a pre-condition for this.

[44] Another risk at certain locations is market manipulation. ISOs can take specific measures against this (see O'Neill et al. 2006). However, these measures could be considered discriminatory in the context of the EU, since they exclude certain market participants from participation in cross-border energy option trading.

When implementing cross-border energy options in the European context, TSOs will probably also want to reserve greater balancing and cross-border network capacity in order to maintain the stability and security of the system and the networks. In Europe, deviations between anticipated electricity flows at the time of capacity calculations (on a D-2 basis) and actual electricity flows in real time by means of a probability distribution lead to a higher reliability margin for TSOs and, with it, to lower cross-border network capacity for market participants (EC, 2015a).[45] Of course, the need to reserve balancing and cross-border network capacity depends on the flexibility demand and the available flexibility supply in markets close to real time. If the flexibility supply in markets close to real time meets the flexibility demand, for example, because of the fact that the demand side reacts to the price more strongly than is now the case, then such reservations appear to be unnecessary.

All in all, cross-border energy options in the day-ahead market have clear-cut advantages from the standpoint of the creation of a more complete and flexible market with greater consistency between the various time horizons. With these options, market participants are able to purchase more flexibility to hedge against volume risks in the intra-day and balancing markets. Sellers of flexibility options exchange uncertainty and volatile revenue for stable revenue. At the same time, options also entail potential costs in the form of a decrease in cross-border network capacity for market participants on a day-ahead basis and potentially greater reservations of reserve capacity. Further research, including market and system simulations, is necessary to attain better insight into the net effects and operational implications. There is, as yet, insufficient convergence of balancing markets between countries to make the exercising of energy options at real-time balancing prices possible. The same is true of intra-day markets, but for these the prospects are more favourable; as expected, regional intra-day markets will become a reality in 2017. Then, at that time, cross-border energy options which can be exercised in the intra-day market within the CWE region can be adopted as an intermediate step toward pan-European adoption. The next step is the adoption of cross-border energy options which can be exercised in the balancing market, first on the scale of *coordinated balancing areas* and later on in larger areas.

5.2 Simultaneous alignment of energy provision and reserve capacity

In order to coordinate the provision of energy with the provision of reserve capacity, the optimisation of energy and reserve capacity can occur either sequentially or simultaneously. In the case of sequential optimisation, markets for reserve capacity and energy are priced one after the next. In the case of simultaneous optimisation, bids for both energy and reserve capacity are made at the same moment, and therefore decisions regarding the utilisation of generation units for the provision of energy and the provision of reserve capacity are taken at the same moment. It is important for both types of optimisation that substitution options are taken into account for the purpose of preventing market power issues and reversed pricing. Reversed pricing occurs when, for example, the power plants with the greatest flexibility receive lower compensation than power plants with lower flexibility.

Another important choice is which party decides which power plants are made available for utilisation in markets. In a power pool-like system with central unit commitment and

[45] Article 22.

dispatch, like that in the US, an ISO optimises the utilisation of power plants for the provision of energy and the provision of reserve capacity. Initially, sequential optimisation was used for this, however, virtually all of the ISOs that utilise auctions currently use simultaneous optimisation. In doing so, substitution options are expressed in terms of optimisation restrictions, and the ISO sets the total purchase cost in one optimisation action. These optimisation restrictions are hierarchical in order to guarantee the efficient use of the available flexibility of producers and consumers (Helman et al. 2008). This means that the flexibility has the greatest value in the market in which the fastest reaction is required (e.g., FCR in the European context) and has less value in markets for which a less rapid reaction is sufficient and can be provided by a greater number of participants (e.g., day-ahead markets). This prevents the aforementioned reversed pricing.

In a system with self-commitment and dispatching, as is utilised in most EU countries,[46] market participants must decide for themselves which power plants are reserved for the provision of energy and which for the provision of reserve capacity. To do this, they must weigh the costs of provision in one of the markets against the opportunity costs of provision in the other market. Producers are guided in this consideration by market incentives, such as the gate closure times of sub-markets and potential revenues from the various sub-markets on which trading occurs bilaterally or via power exchanges and those on which TSOs are active. The hierarchical optimisation limitations, as mentioned above, are also possible in a system which includes self-commitment and dispatch. For example, in the Dutch market for emergency capacity, the revenues are supplemental with respect to revenues that can be earned on the day-ahead market (see section 2). In principle, markets with self-dispatch would be able to contain all aspects of unit commitment and scheduling (Wilson, 2002).

However, due to the unpredictability of the residual demand and the non-convex character of unit commitment choices which may result in several market balances, others call into question whether optimal coordination of the provision of energy and reserve capacity can be achieved with self-dispatch (Green, 2008; Borggrefe and Neuhoff, 2011). It is becoming increasingly more complex for market participants to decide whether they will provide energy and/or capacity services via bilateral (including OTC) transactions, via the day-ahead and intra-day markets of power exchanges or via reserve and balancing markets which are organised by TSOs. Furthermore, portfolio bidding brings with it uncertainty about the commitment of power plants for TSOs. As a result of this, TSOs are obliged to adhere to reliability margins in their congestion management in order to overcome deviations between predicted and actual commitment of power plants at various locations. These reliability margins limit the available interconnection capacity for market participants and, with it, access to foreign flexibility. So, portfolio bidding leads to inefficiencies in the simultaneous coordination of energy and congestion management. For both of these reasons, the question becomes whether self-dispatch and portfolio bidding (which originate from a bilateral market organisation) can be maintained in a more centralised and increasingly European market design.

Green (2008) and Borggrefe and Neuhoff (2011) consider the integrated purchase of energy and reserves by the TSO to be unavoidable for the purpose of deploying the available flexibility of generation units as efficiently as possible in the context of the increasing demand for reserve capacity in a more sustainable energy system. In addition, they advocate

[46] Italy, Greece, Poland, Romania, Slovakia (see ENTSO-E, 2015a) and Ireland are exceptions to this.

the adoption of power pools in Europe, although they also mention the transaction costs that are involved with such a fundamental adjustment to the market. Because this contradicts the current European target model, which assumes self-dispatch and congestion management based on zones (ACER, 2015a)[47], implementation of an adjustment like this is improbable in the short term. Therefore, throughout the remainder of this discussion, we will assume the current Dutch (and European) context which includes self-dispatch.

Given self-dispatch, the following parameters hinder optimal coordination of the provision of energy and reserve capacity:

- Dissimilar gate closure times for energy and reserve capacity markets
- (Too?) limited opportunities for including technical and economic limitations, such as start-up costs, in the bidding format
- Obligation to make symmetrical bids limits flexibility supply of RES

The barrier related to each of these parameters or aspects will be discussed first followed by possible policy measures.

Barrier: Dissimilar gate closure times for energy and reserve capacity markets
In the Netherlands, the gate closure times for markets for FCR capacity (weekly) and for aFRR capacity (yearly, per quarter) differ from the gate closure times of the day-ahead and the intra-day markets. Consequently, producers must commit themselves for the long term for the provision of aFRR, in particular, and do not have the option to offer aFRR capacity for a portion of the year or to revise an earlier choice to provide capacity and/or energy to another market. This sequential market design is sub-optimal and also limits the number of potential providers of aFRR. ACER/CEER (2015) has shown that in 2014 the cumulative market share of the three most important providers of aFRR in the Netherlands was 100%. Furthermore, it is probable that premature setting of reserve capacity leads to higher capacity prices, given that bids will be based on opportunity costs and that the uncertainty with respect to fuel costs and the resultant day-ahead and intra-day prices is high. This uncertainty is probably factored into the opportunity costs and, along with them, into the capacity bids (ACER/CEER, 2015).

Possible policy measure: Adoption of similar gate closure times for energy and reserve capacity markets for the purpose of stimulating day-ahead and intra-day trading in reserve capacity
By implementing similar gate closure times for energy and reserve capacity, market participants will be better able to consider the trade-off between the provision of energy on the day-ahead market and the provision of reserve capacity on FCR or aFRR markets. This also reduces the uncertainty regarding prices in the day-ahead and intra-day markets and, with it, the risk premium for opportunity costs in capacity bids. The question, though, is whether this encourages a sufficient supply of reserve capacity. It is possible that pre-qualification requirements, such as a reaction speed of 30 seconds, an upward regulating and a downward regulating speed of a minimum of 7% per minute and the availability of automatic capacity regulation, can only be successfully met by very few of the market participants. In that case, more frequent market clearing is hindered by a lack of market liquidity. In addition, Green (2008) calls into question whether separate, simultaneous day-ahead auctions for energy and reserve capacity can successfully coexist.

[47] Annex I, p. 8.

If there is a sufficient supply of (foreign) reserve capacity on intra-day time scales, TSOs can contract (a portion of) the reserve capacity on an intra-day basis. From the perspective of operational network security, TSOs will want to be certain that there is still sufficient capacity available on these time scales to meet the need for reserve capacity and will, therefore, want to offer conventional power plants sufficient start-up time by continuing to contract a portion of the capacity on a day-ahead basis. On the other hand, the uncertainty regarding programme deviations and, with it, the need for reserve capacity is probably less in the short term, resulting in the fact that TSOs need to contract less additional capacity on an intra-day basis. TSOs should then also be obliged to update their calculations for the required amount of reserve capacity on an intra-day basis and to obtain a portion of the required reserve capacity on an intra-day basis if this is deemed economically efficient and possible based on the operational network security calculations. It is also conceivable that if the potential flexibility of storage and demand response increases, these new flexibility providers can meet the TSO's need for reserve capacity. In their pre-qualification requirements, TSOs must offer sufficient space to these new providers. These measures will result in lower system balancing costs.

Barrier: Opportunities for including technical and economic limitations, such as start-up costs, in the bidding format may be too limited
With bilateral trading, participants may use any bidding format they wish. Initially, in organised markets, there were only simple bids. Market participants internalised fixed production costs and technical limitations in their bids. However, if a sale is 'at the money' (i.e., the supply at the equilibrium price is greater than the volume required to meet the demand), only a portion of a simple bid is carried out at the relevant point in time. With partial execution of a bid, though, producers run the risk of a technically impracticable (due to required ramping starting from the previous hour or up until the following hour) or uneconomical production schedule. That is the reason that block bids have been permitted. With a block bid, an owner of a conventional power plant can offer its production for several consecutive hours, whereby the bid is only executed if the desired average price is attained. However, a standard block bid provides no opportunity to explicitly include technical and economic limitations, such as start-up costs, in the bid.[48]

Possible solution: Advanced block bids or multi-part bids
With the increase in the share of weather-dependent renewables in the electricity system, daily demand curves have become less predictable. It is for this reason that new types of block bids have been developed. Start-up conditions can be explicitly included in at least two types of block bids: load gradient and minimum income condition (MIC) block bids (PCR, 2013; PCR, 2014). In a load gradient block bid, limitations apply to the maximum increase and decrease between the accepted volume in a period and the accepted volume in contiguous periods. In an MIC block bid, the execution is contingent on a seller meeting an MIC or on a buyer meeting a maximum payment term. The limitation or condition consists of a component for fixed costs and a component for variable costs per MWh, both for the total amount of energy of the order. Furthermore, technical and economic limitations, such as start-up costs, can also be included in profile block bids, whereby the execution is dependent

[48] In addition, block bids result in non-linear prices and make market clearing more difficult than it would be with a simple bid with linear pricing.

on the execution of another block bid. According to the APX website, trading is currently possible in the form of MIC and profile block bids.[49]

According to Neuhoff et al. (2015), block bids have three disadvantages. First of all, standard formats cause limitations when it comes to representations of flexibility, in particular in relation to demand response. Secondly, different types of block bids are used in different Member States. Thirdly, in many types of block bids, start-up costs cannot be explicitly included. In those cases, market participants must internalise a portion of the inter-temporal costs. The third disadvantage seems less important as long as at least a load gradient, an MIC or a profile block bid is available for market participants.

With multi-part bids, components of the short-term marginal costs of sales bids, such as start-up costs and technical production limitations, including response speed and minimum and maximum production limits, can be represented explicitly. Neuhoff et al. (2015) see this as a way to achieve harmonisation between EU Member States that may not be able to be attained with further refinement of block bids. Multi-part bids are being used in the US, Ireland and Spain (and in Italy and Spain for system services). Whether or not it is necessary to replace block bids with multi-part bids is still unclear and requires further research, which falls outside the scope of this study.

Barrier: Obligation to make symmetrical bids limits flexible supply of RES
In the capacity markets for PCR (the Netherlands and Germany) and aFRR (the Netherlands), market participants must supply positive as well as negative reserve capacity. This makes the provision of reserve capacity for RES less profitable. If RES must be able to provide upward regulating capacity, RES can produce less than possible and, as a result, revenues from the sale of electricity, including production subsidies, are lost. From a social perspective, this can also lead to the waste of renewable energy.

Possible solution: Abolish symmetrical bids for reserve capacity products
According to Ecofys (2014), TenneT is already considering making non-symmetrical bids for reserve capacity products possible. TenneT (2015b) indicates that ENTSO-E is already working toward separate contracts for upward and downward regulation. Provision of non-symmetrical products is also part of the draft European Regulation on Electricity Balancing (ACER, 2015a). Therefore, implementation of this solution seems to be only a matter of time.

[49] https://www.apxgroup.com/trading-clearing/day-ahead-auction/

6. Policy implications and research suggestions

The table below outlines the implementation of the various measures proposed in the coming 5-10 years and the responsible parties, including their roles.

No.	Measure	Implementation	Responsible party/parties
1	Shortening the time resolution of day-ahead market products to 15 minutes	There do not appear to be any obstacles for additional DAM products with 15-minute time resolutions by the national or regional power exchanges. In an EU context, consultation regarding adjustments to DA products is planned between market participants, TSOs and regulators after the end of July 2017 (EC 2015a, Art. 40). In line with this, DAM products with shorter time resolutions may be adopted at the EU level in 2018.	APX & other NEMOs (proposal), TenneT / TSOs (implications for energy programmes and transport prognoses), ACM/NRAs (approval) NEMOs (implementation)
2	Stimulation of cross-border trade through marginal pricing of energy products over all time scales in (Northwest) Europe.	Marginal pricing DA market already a reality throughout a large part of Europe and point of departure PCR algorithm (EC 2015a, Art. 38). Marginal pricing on ID market appears to be a logical consequence of adoption of flow-based method (planned for 2017, EC 2015a, Art. 55) but contradicts the intention to implement continuous trading. Marginal pricing balancing energy within 1 year of EB Regulation entering into force, approx. 2018 (ACER 2015a, Art. 42).	TSOs (proposal and implementation BM), NRAs (approval), NEMOs (implementation DAM and IDM). EC/ ACER/ ENTSO-E: Adjustment of EC (2015a) on the point of continuous trading to make marginal pricing on ID market possible.

No.	Measure	Implementation	Responsible party/parties
3	Adoption of balancing markets with reactive TSO activation strategy in (Northwest) Europe	Activation of bids by TSOs before the gate closure times of balancing energy markets is not permitted, except in the event of an alert or emergency in the system; the reason for this is to safeguard fair competition between BSPs (ACER, 2015a, Art. 43). Balancing energy must be contracted as close to real time as possible, and the gate closure time for balancing energy must lie after the intra-day market to the greatest extent possible (ACER, 2015a, Art. 35). ACER does not consider ex-post nomination worthwhile. In addition to contracted suppliers of reserve capacity, all BSPs that fulfil the pre-qualification requirements may also place bids for balancing energy (ACER 2015a, Art. 27 (6)). The imbalance settlement must encourage BRPs to strive for a balanced position or to help the system to recover the balance (ACER 2015a, Art. 55 (1c)). Proposal for single imbalance price is planned within 1 year of EB Regulation entering into force, approx. 2018. Implementation before 1 July 2019 (ACER 2015a, Art. 24). Balancing responsibility for RES is planned as of 1 January 2016 for all new support mechanisms (EC, 2014).	TSOs (proposal and implementation), NRAs (approval), other stakeholders including ENTSO-E, ACER and NEMOs (consultation); see ACER, Articles 5 and 6 (2015a). ACER and EC have back-up roles. EZ, TenneT and ACM play a role in persuading foreign and European parties that market participants must be enabled to deliver balancing energy in real time. The same applies to market participants, which must always be enabled to contribute to the recovery of the system balance.

No.	Measure	Implementation	Responsible party/parties
4a	Stimulation of cross-border intra-day markets by means of dynamic allocation of network capacity	Adoption of a single ID market is planned for the summer of 2017 (16 months after the end of July 2015; thereafter 1 month consultation, a minimum of 6 months for approval). Thereafter, the adoption of energy options may occur if preparations begin this year (earlier adoption may be possible at the regional level).	TSOs (proposal and implementation allocation network capacity), NRAs (approval), NEMOs (implementation energy options). Consultation between ENTSO-E, ACER and market participants (EC, Article 12, 2015a).
4b	Stimulation of cross-border balancing markets by means of dynamic allocation of network capacity	Implementation of dynamic allocation of network capacity is planned within two years of EB Regulation entering into force, possibly in 2019. Initially, this will only be used for RR at the regional level, given adoption of multilateral TSO-TSO model with CMOL list as of 1 July 2018 (Art. 15 from ACER (2015a)). Also for mFRR at the regional level, given adoption of multilateral TSO-TSO model with CMOL list after 1 July 2020 (Art. 17). Also for RR and mFRR at the EU level as of 1 July 2022 (Arts. 16 and 18, respectively). Also for aFRR at the regional level after 1 July 2020, given adoption of multilateral TSO-TSO model with exchange and optimisation of activation of all balancing energy bids, and as of 1 July 2022 for aFRR at the EU level (Arts. 19 and 20, resp.).	TSOs (proposals and implementation), NRAs (approval of proposals), other stakeholders including ENTSO-E, ACER and NEMOs (consultation); see ACER, Articles 5 and 6 (2015a). ACER and EC have back-up roles.

No.	Measure	Implementation	Responsible party/parties
5	Adoption of equal gate closure times for energy and reserve capacity markets for the purpose of stimulating day-ahead and intra-day trade in reserve capacity	Plans for similar GCTs for reserve capacity markets are included in ACER (2015a), Art. 12. Implementation in a regional context within 6 months of regulation entering into force, possibly at end of 2017, Art. 23. Reserve capacity must be contracted as close to real time as possible, max. 1 month in advance, for a maximum period of one month (ACER, 2015a, Art. 37 (2)). Thereafter, adoption of the same GCTs for energy and reserve capacity markets can occur by moving the gate closure time for contracting reserve capacity up to the GCT of the day-ahead market and subsequently re-opening the reserve capacity market for intra-day contracting. First on a regional level, thereafter on the EU level.	TSOs (proposal and implementation), NRAs (approval), other stakeholders including ENTSO-E, ACER and NEMOs (consultation); see ACER, Articles 5 and 6 (2015a). ACER and EC have back-up roles.
6	Evaluation of block bids and comparative analysis with multi-part bids	Results of evaluation and comparative analysis may serve as input for consultations between market participants, TSOs and regulators regarding DA and ID products which are planned after the end of July 2017 (EC 2015a, Arts. 40 and 53, resp.).	NEMOs (consultation and implementation)
7	Abolishment of symmetrical bids for reserve capacity products	Separate procurement of upward and downward regulation for FRR and RR (ACER, 2015a, Art. 37 (5)). Within 18 months of entry into force of regulation (ACER, 2015a, Art. 13), approx. end of 2018.	TSOs (implementation)

During this study, it appeared that based on European legislation and regulations several of the policy measures above would be adopted in the next 5-7 years, in particular the European regulations in the form of Network Codes for Capacity Allocation and Congestion Management (CACM) and the draft Electricity Balancing (EB) Regulation.
As a supplement to this, we propose the following policy measures:

- Shortening the time resolution of day-ahead market products to 15 minutes
- Marginal pricing of products in the intra-day market
- Implementation of similar gate closure times for energy and reserve capacity markets for the purpose of stimulating day-ahead and intra-day trade in reserve capacity
- Dynamic allocation of network capacity on an intra-day basis and cross-border energy options

These measures have been proposed from the standpoint of the belief that adjustments to the electricity system will occur incrementally, with the current situation as the starting point ('brownfield' instead of 'greenfield' situation). Adoption of these practical policy measures may take place in the next 5-10 years.

Suggestions for further research
Further research would be useful for the implementation of some of the aforementioned policy measures. Likewise, research into the need for additional policy measures, in addition to those mentioned above, is also conceivable. In this research, the following (policy) queries are important:

- Can block bids be used on a larger scale? Do multi-part bids have significant advantages over block bids?
- Is marginal pricing of capacity products desirable?
- Can energy and reserve capacity be optimised adequately in two simultaneous markets, or is one integrated market required?
- Is there sufficient flexibility supply close to real-time to make dynamic allocation of network capacity possible?
- To what extent does the organisation of the market (e.g., pre-qualification requirement for the supply of reserve capacity, the design of block bids) hinder access to flexibility markets for demand response?
- What are the current and anticipated future business models of market participants on various sub-markets of the wholesale electricity market?
- What are the effects of a different market organisation for the future business models of providers of flexibility options (manufacturers, aggregators of decentralised production and demand response, storage owners)?
- Is it possible to map out these effects quantitatively with ECN's COMPETES Model with which electricity markets are modelled? If so, how?

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