Bidding zone configuration

A REPORT PREPARED FOR THE MARKET PARTIES PLATFORM

November 2013

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Executive Summary

Background and context of the report

MPP commissioned Frontier and Consentec to support them in the ACER consultation "The influence of existing bidding zones on electricity markets" so that ACER comes to well-informed conclusions based on appropriate assumptions and the appropriate scope of its cost-benefit analysis.The report and the consultation on the reconfiguration of bidding zones are set in the context of the European Electricity Target Model, which restricts the degrees of freedom for the discussion.

Dealing with congestion – various options available

The challenge to **organise efficient national/international congestion management** can be tackled by various measures, where the reconfiguration of bidding zones is just one of many options to deal with congestion. Other options to consider include grid investment and reinforcement, redispatching power stations and managing the location of new power stations and loads.

When assessing bidding zone configuration **social welfare effects must not be mixed up with distributional aspects** of which stakeholders and geographic regions should financially contribute to the various measures that help relieve grid congestion in the interconnected European power system. . This holds all the more as the **current market framework already foresees compensation mechanisms,** e.g. ITC mechanism and funding for projects of common interest (PCI), between areas, although they may need to be refined.

Reconfiguration of bidding zones – economic evaluation has to take into account main trade-offs

With regard to the reconfiguration of bidding zones the economic evaluation implies:

- **Redispatch costs do not per se constitute additional net costs and thus a loss of welfare**. In other words: Lowering redispatch costs is not equivalent to increasing social welfare. Therefore, lowering redispatch costs should not be regarded as the primary objective of bidding zone design. Redispatch costs are merely one of various aspects to consider.

- **Loop flows are no suitable indicator for assessing the efficiency of congestion management** – In the wording of the consultation document ACER seems to imply that lowering or containing loop flows should be an objective or criterion of the reconfiguration of bidding zones. We consider this presumption as inappropriate. Loop flows are not *per se* bad, because:

- Loop flows are not created by congestion, and they are not eliminated by the removal of congestion;
- zonal market design requires the acceptance of loop flows; and
- loop flows are more a distributional concern (of who should pay) rather than net welfare concern.

- **Any re-design of bidding zones must account for its impact on market liquidity as an important dimension of total welfare** – Downsides of less market liquidity could include, among others:
  - Increased transaction cost and thereby **"frictional" welfare losses** (even if trading volumes and price signals were unaffected);
  - fewer or less reliable indications of the future value of power from wholesale markets which may lead to ill-informed decisions and **inefficient investments**; as well as
  - increase in cost of risk due to lack of trading partners and subsequently **fewer investments** e.g. in to power stations or higher retail prices.

- **Creation of smaller bidding zones could create issues of market power** – The larger the bidding zone, the less concentrated market shares from companies will be particular in the spot and forward market. Potential market power in redispatch may be tackled by other means.

- **Creation of smaller bidding zones could hamper retail competition** – Retailers have to adjust their electricity procurement strategies taking into account the price difference between bidding zones in their procurement strategies. Hence, procurement will become more complex encompassing new hedging instruments – if available. In the worst case, the higher costs may drive (some) retailers out of the market or prevent retailers from entering the market in the first place.

- **A stable and predictable investment climate is key for long-term investments and part of the investment signal** – The mere threat of a regular reassessment and potential reconfiguration of bidding zones may undermine the credibility of the price signals and investment climate. Consequently, the – even potential – instability of the bidding zone configuration may contradict the position[1] of the European Commission that a functioning market should deliver appropriate investments.

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1 "Making the internal energy market work", COM(2012) 663 final, Brussels, 15.11.2012, p. 12f (http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=CELEX:52012DC0663:EN:NOT)

- **Permitting procedures rather than lack of economic signals from bidding zones are the main obstacle to grid investment** – The reconfiguration of bidding zones, e.g. into smaller units, may jeopardize attempts to streamline the permitting procedure on a European and national level. This is because authorities may argue that – with smaller bidding zones - market forces are at work sufficiently handling congestion management. This might lead to the administration of scarce network resources rather than the optimal development of the European grid.

- **Investment signals from electricity prices for generators are only one of many decision criteria** – The importance of price signals for the investment decisions of generators depends on various factors, e.g. the need for additional plant capacity, the exposure of investors to market prices, the feedback with market liquidity.

- **Investment signals from electricity prices for large customers follow similar logic as for generators** – Similar to generation, locational decisions of large customers depend on various factors. In addition, changing bidding zones will increase the complexity of electricity procurement, which substantially reduces the benefits from locational signals.

- **Any reconfiguration of bidding zones creates additional transaction costs** – Transactions costs from reconfiguration must not be neglected in the assessment. These could relate to the costs involved in defining new zonal borders, of updating IT systems and of redrafting and adjusting contracts to reflect new bidding and delivery zones.

1 Introduction

1.1 Background

The electricity system and market is characterised by certain constraints on cross-border transmission capacities. In many cases the constraints are allocated to national borders or borders between transmission system operators (TSOs). Only in few cases are transmission constraints also exposed to the market within a TSO system (e.g. in Norway, Sweden or Italy).

Market participants will regard a part of a system without transmission constraints visible to trader as a bidding zone. A bidding zone can be regarded as a regional market or a virtual delivery point to which a uniform electricity price can apply for a certain delivery product.

The Agency for the Cooperation of Energy regulators (ACER) is now questioning whether the current design and borders of bidding zones are suitable and efficient response to managing network congestion and what criteria should be applied when considering an alternative delineation of bidding zones. ACER has issued a consultation document "The influence of existing bidding zones on electricity markets"[2] seeking views on the influence of existing bidding zones on the electricity market with regards to market liquidity, market competition, investment signals and market efficiency. The consultation document is in the context of the joint initiative of ACER and ENTSO-E for the early implementation of the Network Code on Capacity Allocation and Congestion Management (CACM).

The Market Parties Platform (MPP) is a cooperation of energy industry associations in the Central West European (CWE) electricity market (includes the Benelux, France, Austria and Germany). MPP's aim is to actively promote the creation of an integrated CWE electricity market and realize efficient coupling with the surrounding regions. These steps will increase the efficiency of the market and therefore bring benefits to consumers of electricity in this region. MPP's activities are strongly linked to those of Eurelectric. The MPP is very keen to support the consultation so that ACER comes to well-informed conclusions based on appropriate assumptions and the appropriate scope of its cost-benefit analysis. From the MPP's perspective the discussion on reconfiguring bidding zones should include economic and political cost factors. The study indicates how these views could be included in the further analysis.

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2 ACER, *The influence of existing bidding zones on electricity markets*, Consultation document, PC_2013_E_04, 31 July 2013.

1.2 Scope of the report

This study supports the response of MPP members to the ACER consultation and adds vital information on what economic and political cost factors should be taken into account, in case the reconfiguration of bidding zones is considered.

The goal of the study is to develop reliable arguments on the impact of bidding zone reconfiguration on (wholesale and retail) market efficiency, liquidity, competition and further economic indicators and on the associated welfare losses and gains. The study should deliver a qualitative argumentation taken into account experiences in other countries where a price zone has been reconfigured in the past. Arguments should support and qualify the welfare effects of bigger bidding zones compared to smaller zones with possible efficient cross zonal exchange.

1.3 Context of the report

The report and the consultation on the reconfiguration of bidding zones are set in the context of the European Electricity Target Model (ETM), which restricts the degrees of freedom for the discussion. The objective of the ETM[3] is to ensure an optimal use of power generation plants and transmission infrastructure across Europe to

- ensure optimal use of transmission network capacity in a coordinated way by efficient capacity calculation and definition of bidding zones for capacity allocation and congestion management; and
- achieve reliable prices and liquidity in the day-ahead market and efficient forward and intraday markets.

Hence, this model foresees

- a zonal approach based on bidding zones (and thereby also zonal wholesale prices) as opposed to a nodal model (where electricity prices are determined per physical electrical node);
- a market organisation based on bilateral trading between decentralised market parties with the vision of an emerging liquid wholesale markets in the forward, day-ahead and intraday markets; and

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3 For an overview of the pillars of the ETM see: CEER, *European electricity market: target model, infrastructure and security of supply*, presentation by Peter Plug at the EEF workshop, 17 June 2011.

- TSO coordination with regard to cross-border capacity allocation and management (as well as potentially also cross-border cost allocation) and system security.[4]

In addition, the market design should support the achievement of RES targets on a European level and allow the optimal integration of RES generation into the European electricity system.

1.4 Structure of the Document

This document is structured as follows:

- **Section 2** – The redesign is not by far the only measure available for network congestion management. In this section we explore alternative options and thereby put the option of redesigning bidding zones into perspective.
- **Section 3** – Here we discuss criteria which should be taken into account when considering the benefits and costs of redefining bidding zones. Here we draw and expand on aspects which ACER has raised in its consultation document, including:
  - Market efficiency;
  - market liquidity;
  - market power;
  - investment signals and risk mitigation; as well as
  - transaction costs for reconfiguration of bidding zones.

In each section we start out with statements or questions from the ACER consultation document.

[4] ACER, *Framework Guidelines on Capacity Allocation and Congestion Management for Electricity*, FG-2011-E-002, 2011.

2 Dealing with congestion – various options available

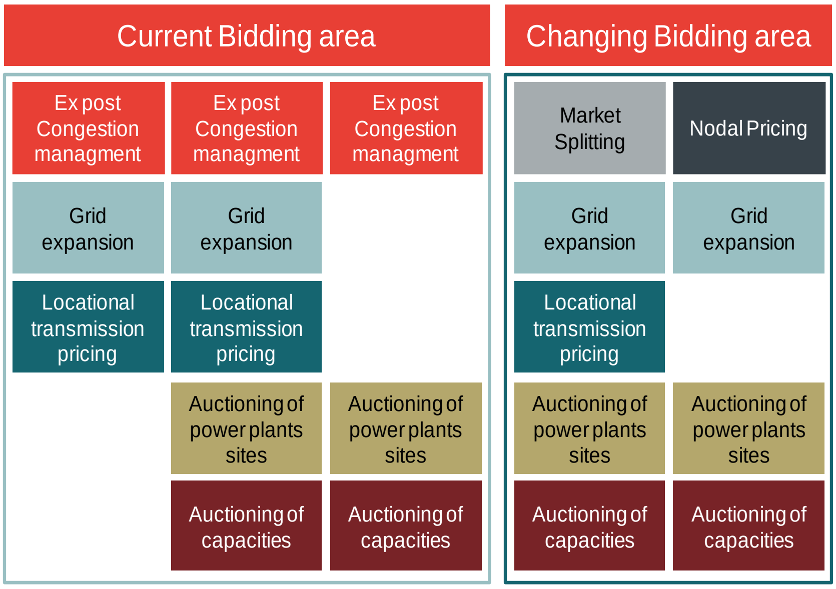
ACER consultation document

Question 1 (p. 8) – How appropriate do you consider the measure of redefining zones compared to other measures, such as, continued or possibly increased application of redispatching actions or increased investment in transmission infrastructure to deal with congestion management and/or loop flows related issues? What is the trade-off between these choices and how should the costs attached to each (e.g. redispatching costs) be distributed and recovered?

- **Various measures – apart from reconfiguring bidding zones can serve to improve on network congestion** – The main challenge which ACER wants to address is how to organise **efficient national/international congestion management**. This challenge can be tackled by **various measures**, where the reconfiguration of bidding zones is just one of many options to deal with congestion:
  - Grid investment and reinforcement – which will relieve congestion on certain lines;
  - redispatching power stations close to real-time; as well as
  - managing the location of new power stations and loads, which may include
    - *Locational electricity pricing* – changing bidding zones can send locational signals to generators and demand, thus, relieving congestion by locational decisions, where to invest.
    - *Locational transmission pricing* – within a bidding zone can send locational signals to generators and demand and leaves the uniform energy price unaffected.
    - *Auctioning of power plants sites* – the auction of sites can send locational signals to generators, where to locate their plants.

  It is worth noting that some of these options can be combined and can be applied without changing the current bidding zones. Hence, they can supplement the existing congestion management measures. For example within a current bidding zone the ex post congestion management may be supplemented by grid expansion and locational transmission tariffs to relieve congestion (**Figure 1**).

Figure 1. Options and combination for congestion management[5]



Source: Frontier/Consentec

- **Social welfare effects must not be mixed up with distributional effects when assessing options for congestions management** – Grid investments may be best placed to relieve congestion in the network. However, it may be the case that grid investment needs to be undertaken in bidding zone B to efficiently relieve congestion in bidding zone A. In this case the benefits and costs of the investment fall geographically apart. While this will not change the overall positive impact of an investment on social welfare, it will complicate the funding of the efficient investment. A situation may be perceived as "unfair" where participants in bidding zone B fund an investment through network tariffs while the benefits in zone B may be lower than the investment cost an significant benefits accrue to market participants in zone A. As long as in aggregate the benefits exceed costs there should always be the opportunity for compensation payments from A to B which make constituents from both zones better off. Nevertheless, it is worth noting that the lack of clear *ex ante* rules for cost sharing of cross-border congestion relieving measures can have an adverse effect on social welfare, if this prevents the cost-bearing bidding zone from undertaking them.

5 With regard to "nodal pricing", however, we note that this tends to contradict the ETM.

- **The current market framework already foresees compensation mechanisms between areas, although they may need to be refined**[6] – The EC framework includes the mechanism of
  - Inter TSO compensation (ITC)[7] – here TSOs in transit countries are compensated for hosting transit flows for which they receive neither generator entry fees nor system exit fees; as well as
  - funding for projects of common interest (PCI)[8] – The Energy Infrastructure Package foresees as one element the possibility that grid investment cost are not funded by the TSOs (and network users in their area) where the investment is undertaken, but also by TSOs or regions that benefit from such investment.

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6 In addition, technical inter-TSO arrangements such as the installation of phase-shifting transformers may be supportive in alleviating distributional issues while avoiding market distortions.

7 Commission Regulation (EU) No 838/2010 of 23 September 2010 on laying down guidelines relating to the inter-transmission system operator compensation mechanism and a common regulatory approach to transmission charging.

8 Regulation (EU) No 347/2013 of 17 April 2013 on guidelines for trans-European energy infrastructure and repealing Decision No 1364/2006/EC and amending Regulations (EC) No 713/2009, (EC) No 714/2009 and (EC) No 715/2009.

3 Reconfiguration of bidding zone – economic evaluation

In this section we discuss various aspects to be considered when discussing a reconfiguration of bidding zones:

- Market efficiency;
- market liquidity;
- market power;
- investment signals and risk mitigation;
- transaction costs for reconfiguration of bidding zones; and
- distributional effects.

For didactical purposes we have changed the ordering of some of these aspects compared to their presentation in ACER's consultation document.

3.1 Market efficiency

ACER consultation document

Redispatching is very often organised in a non-market based way and this induces further costs (i.e. loss of social welfare), which are not visible within the day-ahead market coupling.

Trade-off between wider bidding zones/potentially higher redispatch costs and smaller bidding zones/potentially lower redispatch costs – The statement by ACER implicitly presumes that redispatch is socially undesirable. However, redispatch should be considered in perspective.

Redispatch costs do not per se constitute additional net costs and thus a loss of welfare. In other words: Lowering of redispatch costs is not equivalent to increasing social welfare. Therefore, lowering redispatch costs should not be regarded as the primary objective of bidding zone design. The static efficiency of congestion management rather depends on the final outturn dispatch, i.e. the superposition of

- generation schedules (created by market participants as a consequence of spot markets); and
- redispatching (by the TSOs).

When comparing a configuration of smaller bidding zones to one with wider zones, while the former may lead to lower costs of redispatching, this may come at the expense of stronger dispatch restrictions in the spot market (cf. "introducing limited capacity" in ACER's consultation document). Hence, it is at best unclear which of the two bidding zone configurations would yield the more efficient final outturn dispatch.

In the following, we further discuss this issue in two steps. First we analyse efficiency properties under ideal market conditions. We then turn to aspects stemming from the difference between real and ideal market conditions.

- **Theoretically ideal congestion relieving measures should be nodal** – If a zonal approach is used for congestion management the dispatch would be optimal only if each power plant in the affected bidding zones had the same congestion relieving effect. In this case the location of the power plant, near or far from the congested line, would have no influence on relieving congestion and the merit orders in the affected bidding areas would lead to an optimal dispatch of the power plants subject to the congestion constraint. However, it is a physical reality that there is an influence of the location of power plants on relieving congestion. Power plants near congested lines do have a significantly higher impact on relieving congestion than other plants. This information is not included in the merit order in the bidding zone.

  This effect is illustrated by the following example. Two exemplary German transmission lines are assumed to be congested.[9] We compare different bidding zone configurations with respect to the effectiveness to relieve these lines, i.e. to reduce the flows by shifting generation between bidding zones. (Note that for this technical assessment it does not matter whether this shifting is achieved by ex ante restriction of transmission capacities or by ex post modification of generation schedules.) The effectiveness has been defined as the ratio of the flow change on the respective line and the amount of power generation required to be relocated between zones or nodes in order to achieve this flow change. When zones are considered, the generation change in each zone is assumed to be evenly distributed among all generators in the zone.[10]

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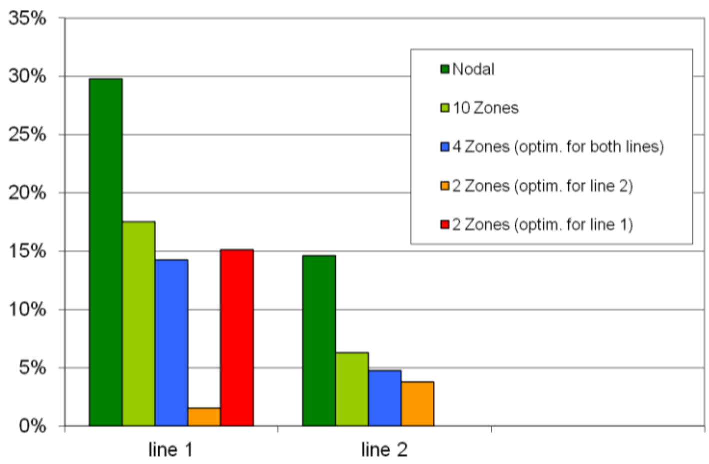
9 The example is based on an analysis conducted for the study "Methodical Questions Regarding the Management of Internal Congestion in the German Transmission Grid (Energy)" by Consentec and Frontier Economics on behalf of Bundesnetzagentur, 2008. The analysis considers two typically congested lines, and the load flow simulations are based on a realistic network model of the European transmission grid.

10 Since the merit order of generators inside a zone does not consider any locational information, it is *a priory* uncertain which generator would participate with which share in the total zonal generation change. Assuming an even distribution among all generators is a reasonable approach to deal with this uncertainty. However, if the TSO(s) wanted to make sure that the relief of the congested line is achieved with the same certainty as in the nodal case, then they would have to assume that the least efficiently located generator in the zone would change its generation first, then the second least efficient one and so forth. Under such assumptions the effectiveness of zones would be even lower than the figures presented in the following.

The analysis shows that the maximum accessible effectiveness in the case of nodal zones (i.e. when each zone consists of one node) amounts to about 15 % to 30 % depending on the line congested. The significant gap to 100 % results from the fact that load flows are always distributed on several parallel paths in meshed transmission networks. The extent of this effect depends on the concrete network topology and can therefore differ significantly depending on the location of congestion. In the example (**Figure 2**), there is a factor of two between the maximum achievable effectiveness for line 1 and 2.

Figure 2. Numerical example – Technical effectiveness of zonal and nodal congestion management with respect to the flows on two German transmission lines



Source: Consentec

When the flows on the lines are controlled by schedules between zones rather than nodes, the effectiveness drops significantly. Even if Germany was split into 10 (i.e. quite small) bidding zones, the effectiveness would already drop to approximately half the amount of the nodal case. If only two (i.e. larger) zones were created, then their optimal shape would depend on the line to be controlled: For example, a configuration that would be optimal for line 1 (red bar in the diagram) would be completely inefficient for line 2. Hence, the exemplary analysis underpins that

- achieving a certain amount of flow reduction on a congested line by limiting zone-to-zone schedules requires much larger amounts of generation to be changed (and therefore, very likely, imply higher cost) compared to nodal redispatching;
- if the number of zones shall remain reasonably limited, then any concrete shape of these zones would only allow a subset of potentially congested lines to be effectively controlled; and

  - consequently, nodal redispatching would still be required despite a prior reconfiguration of bidding zones.

- **In an ideal market, the final outturn dispatch would not depend on the bidding zone configuration** – Since nodal redispatching is required in any zonal market configuration, the configuration of bidding zones merely alters the extent to which the ultimate dispatch is derived from scheduled dispatch and redispatching, respectively. In a perfect market (perfect competition, all players are too small to exert market power), the ultimate dispatch would be independent of the zone configuration.[11]

- **Therefore, only the degree of real-world market efficiency (and not the differences under theoretical/ideal assumptions) is relevant when assessing congestion management regimes** – In large bidding zones, the real-world efficiency of forward and spot markets benefits from a smaller relative market share of individual players and from higher liquidity compared to smaller bidding zones. These aspects are discussed in further detail in subsequent sections.

- **Redispatching is likely to be efficient even if cost information is not perfect** – The degree to which redispatching decisions can be made based on true marginal costs information depends on the particular design of the redispatching process. However, the physical impact of a plant to relieve congestion on a particular transmission line usually differs by factors even between neighbouring substations. Hence, even if the cost information available to the TSO was inaccurate by tenths of percent – i.e. even if the TSO only knew the primary fuel type and the plant technology –, the optimal plants would be selected for redispatching.

- **Redispatching can be developed further** – In bidding zones where the cost efficiency of redispatching is questioned e.g. because of a lack of transparency, the increase of transparency should be the preferred goal (rather than altering the bidding zone configuration in order to reduce

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11 Two effects are neglected here for simplification. Firstly, if cross-zonal transmission capacities are set too prudently (i.e. too low), then smaller bidding zones result in less efficient dispatch, because redispatching cannot "heal" the inefficiency if there is too low inter-zonal exchange in the first place.

Secondly, since redispatching is performed on short notice, start-up and shutdown decisions of (coal fired) power plants are based on the results of the spot market and cannot be "corrected" by redispatching. However, it is important to note that even in a setting with very small bidding zones, any unforeseen event occurring after the start-up/shutdown decision has been made (e.g. plant failure) would have to be addressed by already running plants as well. Therefore, within reasonable bounds of bidding zone sizes and configurations, the efficiency loss of sub-optimal start-up/shutdown decisions due to the bidding zone configuration is not relevant.

redispatching volumes and thereby sacrificing the efficiency of forward and spot markets). In Germany, for instance, technical (location, frequency) and costs information on redispatching measures are published[12] by the regulatory authority. Further degrees of transparency would be achievable if this was socially desired.

Moreover, by (further) development of cross-border redispatching procedures the TSOs can improve the selection of plants for optimal (cost minimal) redispatch. Such optimisation potential can be harvested by improving the cooperation among TSOs, without any detrimental side effect on other market segments.

In ACER's consultation document the occurrence and magnitude of loop flows appears to be treated as an integral aspect of the efficiency of bidding zone configurations. This leads to some implicit intermixing and overlapping of technical and economic arguments. In the following we resolve these overlaps with the aim to provide a **clearer picture of the actually justified role of loop flows** in the discussion on bidding zones.

- **Loop flows are no suitable indicator for assessing the efficiency of congestion management** – In the wording of the consultation document ACER seems to imply that lowering or containing loop flows should be an objective or criterion of the reconfiguration of bidding zones. We consider this presumption as inappropriate. In fact, loop flows are not *per se* bad (even from a cost-efficiency perspective), which is underpinned by the following considerations:

  - **Loop flows are not created by congestion, and they are not eliminated by the removal of congestion** – In a road network, the narrowest section of a route determines the capacity of the entire route. A traffic jam on a congested route results in traffic spilling over to alternative routes, which then may be overloaded as well. Creating more capacity on the congested road section will allow more cars to use the direct route, and the alternative route will no longer be congested.

    However, this is not how power networks function. As soon as power is transported within a bidding zone, there will be both internal and loop flows, as an inevitable consequence of the laws of physics.[13] The occurrence of loop flows is irrespective of whether the network inside

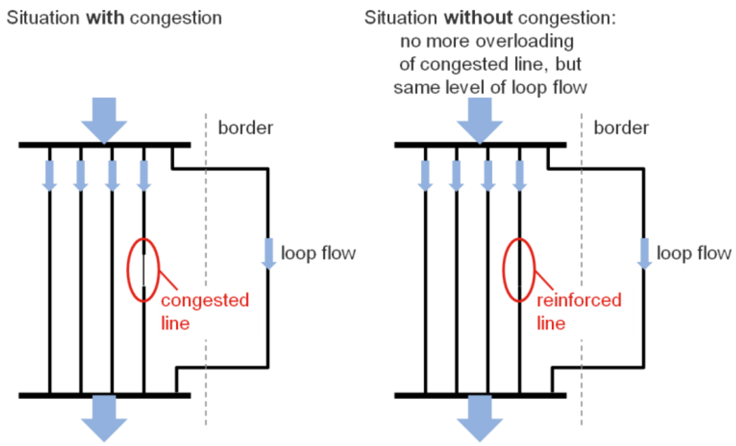
[12] http://www.bundesnetzagentur.de/SharedDocs/Downloads/EN/BNetzA/PressSection/ReportsPublications/2012/MonitoringReport2012.pdf?__blob=publicationFile&v=4

[13] The distribution of flows among internal and loop flows depends on the relative impedance of the various parallel electrical paths between power sources (generators) and sinks (loads), but not one the capacity of any particular (congested) power line.

the bidding zone is congested or not. Consequently, when removing congestion by means of network investment, the magnitude of loop flows may remain constant.

If the congested transmission line, i.e. the "bottleneck", is a single line in a large bidding zone, then the replacement of this line by one of a larger capacity could have a small or even negligible effect on the total impedance of the electrical path between the power sources and sinks. Therefore, the distribution of flows practically remains unaffected. This is schematically illustrated in the following figure.

Figure 3. Independence of loop flows from congestion – schematic illustration



Source: Consentec

This is a realistic case in the short and medium run. For example, the German transmission network comprises a total circuit length of about 34,000 km.[14] Consequently, an expansion by several hundred or even a few thousands of kilometres will not significantly alter the impedance of a long-distance path, e.g. between the north and the south of the country – the more so as parallel investment in neighbouring countries will further contribute to keeping the ratio of the impedances between "direct" and "loop flow" routes similar to the present situation. Thus, the network extension projects will allow for higher amounts of power flows in total by removal of congestion, but the relative share of loop flows will not be materially changed,[15] even if all congestion was removed.

14 https://www.entsoe.eu/db-query/miscellaneous/lengths-of-circuits/, data from 2012, retrieved on 15 October 2013.

15 In contrast to normal transmission lines, the commissioning of direct current (DC) links inside the meshed alternating current (AC) network may help limiting loop flows, because the power that is

- **Zonal market design requires acceptance of loop flows** – Since the occurrence and magnitude of loop flows is not affected by the occurrence of congestion, the location of congested transmission lines would not provide any guidance to the appropriate size and configuration of bidding zones if decreasing loop flows was a target of such reconfiguration. Hence, once one has started in the direction of smaller zones with the aim to reduce loop flows, every configuration of smaller zones would still yield some loop flows. Ultimately, only nodal pricing would be the natural ending point of the process. But nodal pricing is in contradiction to the EU target model which forms the basis of NC CACM and is based on bilateral trading within and between zones.

  Even an enlargement of bidding zones could – nominally – eliminate loop flows: By merging a zone that is deemed to evoke the loop flows with another zone where these loop flows occur, the loop flows would be relabelled as internal flows within the new large bidding zone – even in the theoretical case of an unchanged physical flow situation.

  These considerations show that neither towards smaller nor larger bidding zones the phenomenon of loop flows provides any suitable guidance to an appropriate size and shape of the zones.

- Redispatch cost in connection with loop flows (if these lead to overloading of transmission lines) may be a justifiable cost-efficiency concern. However, in this case it is **sufficient to consider redispatch cost rather than loop flows.**

- **Distributional effect rather than net welfare concern** – Loop flows may be of concern for a different reason (not the cost efficiency / social welfare reason): A TSO affected by loop flows may need to undertake further investment or undertake costly operational measures. The current institutional set-up (for example the politically motivated limit on the inter-TSO compensation mechanism (ITC)) may be ill designed to compensate certain TSOs that suffer from loop flows caused by actions of players in other countries. However, this is a merely distributional effect (costs and benefit are geographically falling apart) and irrespective of overall social welfare. This however, is best **addressed by appropriate TSO compensation schemes and not by reconfiguring bidding zones**. A reconfiguration of bidding zones may help addressing the distributional effects, albeit – in particular when zones become smaller – at the likely

transported via the point-to-point DC links does not have to be transported via the meshed AC network.

expense of reducing social welfare.[16] We understand that the recently enacted Energy Infrastructure Package aims at directly addressing the distributional effects, in particular by sharing the costs of Projects of Common Interest among their beneficiaries. In addition, technical inter-TSO arrangements such as the installation of phase-shifting transformers may be supportive in alleviating distributional issues while avoiding market distortions.

3.2 Market liquidity

ACER consultation document

2.3 Market liquidity (p.6) – At first glance, the larger the zone, the higher the volume (liquidity) of trade cleared into the zone. A reduction in the size of the zone may be interpreted as a reduction in the liquidity of the short-term (day-ahead, intraday) markets inside this zone. This is, however, a too simplistic view, since the liquidity of the market is not only influenced by trades inside the zone, but also by trades between the zones. Thus, an important parameter here is the overall liquidity of all zones covering a given territory. In particular, when trading between zones is organised through implicit auctions or market coupling, the volume (liquidity) of cross-zonal trade will add to the liquidity of trading inside the zones and the overall liquidity in the power exchanges can increase.

2.4 Price Hedging (p.6-7) – (…) the bigger the bidding zone, the higher the liquidity of these hedging instruments. Nevertheless, liquidity of hedging instruments in smaller zones is usually poor. In Continental Europe, Physical Transmission Rights or Financial Transmission Rights may be used as a hedge against congestion costs and they may help the liquidity of the forward hedging market. … Nevertheless, there are designs of hedging instruments, which enable liquidity in the forward market even in the presence of smaller bidding zones (e.g. Nordic countries).

In line with ACER's comments we address two key issues in this section, in particular:

- The effect of reducing the size of bidding zones on **market liquidity**; and
- the possibility of hedging against the **risk of energy price spreads across the borders of newly created bidding zones** in the context of creating smaller bidding zones. In this context we also show a link between this risk and retail competition.

16 Cf. e.g. considerations on real-world market efficiency above, or on market liquidity, market power and investment signals below.

These two issues are also interrelated.

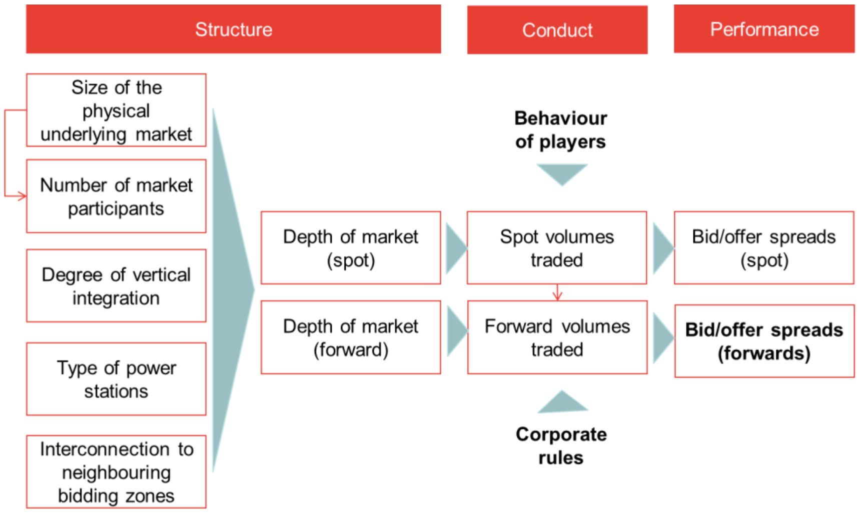
Effect of bidding zone design on market liquidity

- **Liquidity matters and supports investment decisions and efficiency of dispatch** – Liquidity concerns the ability of market players to constantly have available trading partners with which they can enter into contractual positions and also reverse out of them through further trades with the same and other parties and to do so without their individual trades significantly upsetting the level of market prices. Liquidity is essential to the European model of electricity trading, which hinges on a decentralised organisation and bilateral trading between market players. The depth of the market and availability of derivative and/or forward products is particularly important. It is these products that allow market players to hedge risk and obtain market information that is commercially reliable. Downsides of less liquidity could include, among others:
  - Increased transaction cost and thereby **"frictional" welfare losses** (even if trading volumes and price signals were unaffected);
  - fewer or less reliable indications of the future value of power from wholesale markets. Again this increases risk and cost of risks and can adversely affect investment and lead to ill-informed decisions and **inefficient investments**; as well as
  - increase in risk and risk cost due to lack of trading partners and subsequently **fewer investments** e.g. in to power stations or higher retail prices.

- **Bid/offer spreads constitute a useful measure of liquidity also in the context of cost-benefit analysis** – A number of different indicators are used to operationalize and measure the liquidity of a market (**Figure 4**):
  - *Bid/offer spreads* – The bid-offer spread is defined by the amount by which the ask price exceeds the bid. This is essentially the difference in price between the highest price that a buyer is willing to pay for a product and the lowest price for which a seller is willing to sell it. The bid/offer spread represents the transaction cost for participating in a market and is a key measure of liquidity, where more liquid markets are characterised by lower bid/offer spreads. It also provides a monetary valuation of transaction cost in a less liquid market (compared to a more liquid market). If the typical bid-offer spread in a less liquid market was twice as high than in a more liquid market, then the difference in the spreads indicate how much market participants need to sacrifice to close a transaction.

- *Market depth* – This indicates the size of specific orders at which the market would move by a given amount. Market depth is very challenging to measure. Absent publication on existing trading platforms, some energy commodity market participants actually maintain proprietary empirical databases, which allow calibration of bid/offer matrices, where the spread is modelled as a function of order size.
- *Trading volume and number of trades per day actually measure trading activity rather than market liquidity, but are commonly used as liquidity indicators as well* – based on the assumption that high volume and a large number of trades per day (or so) would coincide with low bid/offer spreads and a deep market. Particularly in energy markets, trading volume is additionally observed relative to the underlying physical commodity produced and consumed (so-called market churn) with high multiples suggesting high liquidity.
- *Churn rate* – A variant of the trading volume measure is the churn rate. It describes the trading volume in comparison to the physical consumption in the underlying market. A high churn rate indicates a more liquid market. A churn rate of 1 would imply that a megawatt hour of electricity is traded once in the wholesale market before being physically delivered. Liquid markets would have churn rates (well) above one, indicating that power is not only traded once, but several times as market players adjust their market expectations and positions over time.

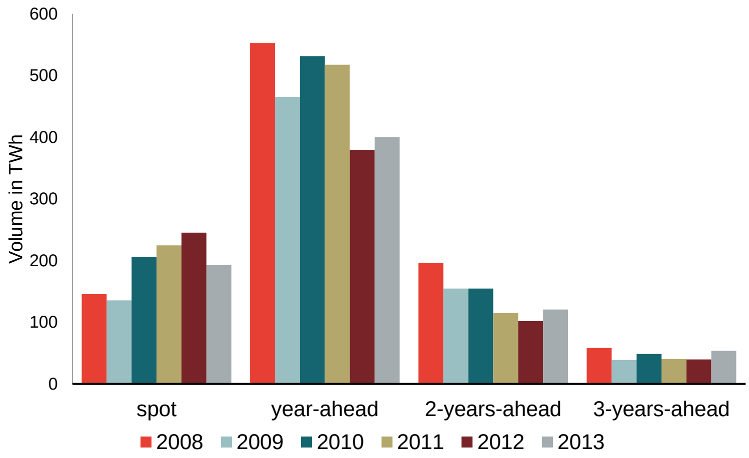
Figure 4. Market logic of liquidity



Source: Frontier

- **Market liquidity tends to fall with delivery term, but even less liquidly-traded products still convey price signals for the medium-term** – Trading volumes from EEX/EPEX illustrate the different levels of liquidity between delivery terms (where the consumption in the underlying German electricity market is ca 600 TWh/a):
    - Spot trades – these are mainly used to optimise positions in the short term and one would expect the volume to be below overall physical consumption in the region; as well as
    - 1-year-ahead trades are an important product as they can serve to procure electricity for retail sales (where most retail sales are contracted on an annual basis). Unsurprisingly the 1-year-ahead market shows the highest trading volumes. We observe that liquidity at the power exchange in this segment roughly corresponds to the volume of the underlying end consumption (but not more) and that trading volumes have been falling of late.

Figure 5. EEX/EPEX trading volumes in different trading periods



Source: Frontier based on Energate

Some argue that markets where liquid trading is confined to prompt years do not convey the price signals needed for the valuation of longer-term investments and are hence irrelevant for "major decisions". Consequently, they argue that the amount of liquidity available in prompt years is deemed irrelevant. We note that this reflects a fundamental misunderstanding of how commodity markets work. The liquid period comprises the prompt three years for most European as well as international energy markets. Transactable prices are a transparent reflection of supply/demand fundamentals including their changes over time. Beyond the liquid period, ease of transaction and transparency decrease the further out we go.

However, high liquidity in the prompt years actually tends to be helpful for investors in long-term assets for two reasons:

- On the one hand, it obviously allows for a better "in the sample" testing of their own market analysis applied to form expectations on long-term prices; and
- on the other hand, each longer-term price expectation has its implied forward price at which it would actually be hedged. In principle, these implied forward prices can be (statistically) arbitraged against the end of the liquid period in case they deviate too much from its extrapolations – thus driving the liquid part of the curve closer to longer term expectations or vice versa.

Market players owned by shareholders, who do not accommodate long-dated risks are bound to consider long-term investments from a hedging perspective. These players will find high liquidity in the liquid period even more helpful to hedge and ultimately finance investments.

- First of all, it facilitates so called "stack and roll" hedging where a long-term risk is hedged by offsetting transactions in the liquid window (e.g. deliveries for the next three years), leaving the investor with basis risk between periods. For example, an investor in a production power plant with a 10 year utilisation period might sell the last seven years as liquid 3 year forwards thus effectively overselling expected production in the third year. Over time these sales are consecutively reduced by buying a year back and reselling the respective last year of the liquid period again. High liquidity reduces transaction cost incurred on the spread trades. Clearly, the investor will be exposed to basis risk in terms of changes in the shape of the forward curve (benefiting when it steepens and losing when it flattens), but this risk may be small compared to the price risk otherwise incurred outside the liquid period.
- An alternative to "stack and roll" hedging is a more tenor consistent transaction. Such transactions typically involve a longer search for willing counterparties and corresponding negotiations. Again, high liquidity in the liquid period will help, because it facilitates (statistically) arbitrage between long-term expectation implied forward prices and forward prices at the end of the liquid period in case the former deviate too much from extrapolations of the latter – thus driving the liquid part of the curve closer to longer term-expectations or vice versa.

- **Basis risk hampers liquidity** – Clearly, most relevant liquidity measures are best defined in terms of products relevant for market participants. Typically, high relevance means low basis risk between the traded product (e.g. year-ahead contract) and the underlying product of commercial concern (e.g. the physical delivery of power in real time). Basis risk may be quality related (e.g. between low and high calorific gas), time related (e.g. between base and peak load or between spot and forward) or locational (e.g. between different hubs or zones). For example, high liquidity in a spot market may be welcomed from the perspective of correspondingly short-term business. For longer-dated exposures spot liquidity is still relevant indirectly to an extent, because it might suggest a good environment for an index to be created against which standard forward contracts could be settled reliably. Therefore spot liquidity can eventually help liquidity to evolve in longer-dated business. Similarly, a regionally confined hub will typically be the less relevant for outside supply and demand the higher the basis risk incurred to actually enter it.
- **Liquidity changes are reinforced by behavioural adjustments of market participants** – We note that there is no well-defined function to

mechanistically explain behavioural changes of market participants resulting from changes in market liquidity and the data used to measure it, e.g. bid/offer spreads. Decisions made by market participants tend to be based on discretionary judgements following commercial logic and accounting for all data available to measure liquidity. However, some energy market players actually may take a more formulaic approach to the matter.

Trading companies typically set their risk limits (and thereby implicitly also their potential trading volumes) in proportion to liquidity, applying for example measures like the bid/offer spread and distinguishing between commodities, products and regions. Such decisions are taken discretionarily based on corresponding analysis by traders and risk controllers. However, once limits are set, more formulaic incentives may apply to influence trading activities within limits. Adjustments to account for liquidity (or the lack of it) are normally made in the valuation of open positions. Such liquidity provisions are typically based on bid/offer matrices, which increase when liquidity declines thus reducing performance and the incentive to trade.

Bulk utility hedging in forward wholesale markets is sometimes driven by the defined share of a company in measured trading volume for hedge products. Lowering trading volumes will thus immediately reduce hedge intensity. Similarly, utility hedging of flexible assets will shrink, where flexibility is explicitly valued and traded based on option pricing theory. Typically, flexible assets tend to be more or less in the money depending on market price. Flexibility has a value which can be monetised, for example, by selling more power into rising power prices when the plant is more often in the money and to buy such hedges back in a falling market when the plant falls out of the money again. However, market moves within the bid/offer range are typically not re-traded and the wider the spread, the less re-trade will actually be undertaken over time.

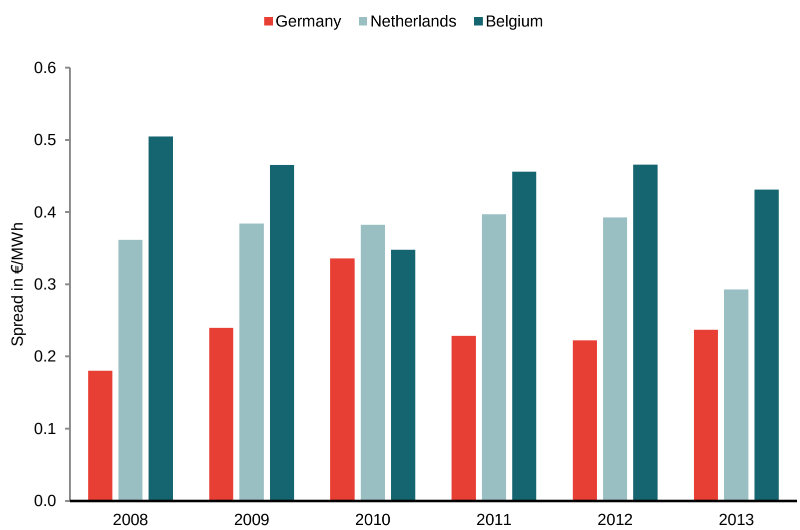
This confirms that any policy measure resulting in a decrease of market liquidity – such as a downsizing of bidding zones – will be reinforced by behavioural adjustments of market participants (the extent of which is complex to forecast).

- **Any re-design of bidding zones must account for its impact on market liquidity** – Redesign of bidding zones is meant to lower redispatch costs, but does not avoid the need for redispatch. In the previous section we discussed to what extent a redesign of bidding zones can help lower (re)dispatch cost. Even if there was a benefit to (re)dispatch cost this would have to be set against the impact on market liquidity. Therefore it is important to understand how adversely market liquidity could be affected by a change in the configuration of bidding zones.

- **Large markets with highly diverse participants tend to be more liquid and therefore incur measurably lower transaction cost** – The size of the bid/offer spread from one asset or product to another will differ mainly because of the difference in liquidity of each asset. The bid/offer spread should decline *ceteris paribus* with the amount of market participants (and the size of the market), because the more market participants, the more potential counterparties with different risk preferences are available for a trade.

  As a first indication to illustrate this relationship, we compare the bid/ask spreads for the differently sized electricity markets of Germany (ca 600 TWh/a underlying physical consumption), Netherlands (ca 120 TWh/a) and Belgium (ca 90 TWh/a) (**Figure 6**). The spreads in the Netherlands and Belgium are substantially higher than the spreads in Germany, which is by far the largest and most diverse wholesale market in Continental Europe. Hence, the comparison is consistent with the hypothesis that the level of the bid-ask spread correlates with the size of the bidding zone. The illustration also allows drawing conclusions on the level of (expected) transaction cost in markets of different liquidity levels. For example, in Germany the bid/offer spread in 2012 represented ca. 0.45% of the wholesale price of electricity on average, while it represented 0.69% in the Netherlands and 0.89% in Belgium.

Figure 6. OTC Bid-Ask Spreads for 1-year ahead products (yearly averages)



Source: Spectron, Frontier calculation

Note: 2013 data up to September 2013

The bid/offer spreads from **Figure 6** can be used to illustrate the potential increase in overall transaction costs by reducing the size of bidding zones. If, for example, Germany was split into smaller bidding zones taken as equal to the Netherlands and Belgium we may assume that the current bid/offer spread in Germany would increase to the levels in the Netherlands and Belgium. This increment (€/MWh) multiplied with either the total consumption in Germany, traded volumes at EEX for different time ranges and the OTC market provides an indication for the overall increase in transaction cost due to reducing the size of the bidding zone.

Table 1. Indicative illustration of annual increase of transaction costs in case of splitting the bidding zone in Germany (using 2012 data)

2012	Difference in Bid/offer spread	German consumption	EEX	EEX + OTC
NL-DE (€/MWh)	0,17			
BE-DE (€/MWh)	0,24			
Volumes (TWh)		600	830	1.380
Increase in Transaction costs (€ Mio.) if				
Spreads reach NL level		**102 Mio.€**	**141 Mio.€**	**235 Mio.€**
Spreads reach BE level		**146 Mio.€**	**202 Mio.€**	**336 Mio.€**

EEX volumes: consists of spot, m+1, y+1, y+2, y+3; OTC volumes: all products

Source: Frontier, Energate, Spectron, Bundesnetzagentur

Depending on the relevant volumes and the increase in the spreads (either to the level in the Netherlands or Belgium) the calculations indicate an increase in overall transaction costs in the order of € 102 Mio. to € 336 Mio. (**Table 1**).

- **Market liquidity measures cannot simply be added across regions** – ACER seems to imply that it would be possible to simply add trading volumes over several countries to obtain an indication of liquidity. We would not consider this approach as admissible. The depth of a market is a key feature of liquidity. For example, constraints on cross-border capacity can hamper the depth of the market and it would be inappropriate to simply add trading volumes of a neighbouring country (B) when calculating liquidity of country A. In order to get an appropriate picture of the market liquidity respective indicators for countries over different trading periods should be calculated.

  That the simple addition of trading volumes across borders of neighbouring bidding zones does not make sense is also evidenced by the above case study of Germany, the Netherlands and Belgium. These three bidding zones are physically interconnected[17] and they are also linked through the Central Western Europe (CWE) market coupling. Based on hourly spot prices from EPEX, APX and BELPEX for 2012 the prices equilibrated between Germany and the Netherlands in 19% of hours until October 2013, between Germany and Belgium in 32%, and between the Netherlands and Belgium in 59%. According to the logic implied in the ACER consultation, it should be possible to simply add trading volumes across borders. The test whether this is sensible, however, is how the markets perform. If the logic in the ACER consultation were correct, then one would expect that bid/offer spreads are identical across the three bidding zones. However, we have shown that this has consistently not been the case (**Figure 6**). Therefore, while, e.g. the Netherlands and Belgium might somewhat benefit from market liquidity in Germany (i.e. bid/offer spreads in these zones might be even higher in the absence of liquidity in Germany), the bid/offer spreads across the regions clearly do not level out.

Dealing with cross border price risk between newly created bidding zones

- **Perfect markets in which all risks – including cross-border price risk – can be hedged remain a theoretical illusion** – Some argue that wherever basis risk matters, it will find its own market where it can be hedged away. This hypothesis ignores that any basis risk between markets or products tends to attract a smaller number of market participants to trade the very basis in its own right compared to the integrated market or product free of basis risk. As a consequence, the integrated market or product free of basis risk should be expected to be more liquidly traded than any of its fragmentations.

- **The design of bidding zones is critical for market liquidity** – In the following we assume that the reconfiguration of one bidding zone results in smaller bidding zones. In principle, reducing the size of the bidding zone may deter market participants from trading, which results in a reduction of traded volumes and possibly depth of the market. As a consequence the confidence in the underlying price for financial contracts may decrease and dry out the forward market.

  When one bidding zone is split into several bidding zones the wholesale (day-ahead/forward) power exchange market can be organised in various ways, for example:

17 Belgium is not directly physically connected to Germany, but still strongly interlinked via the Netherlands (and the geographic link e.g. through the Dutch province of Limburg) and France.

- *The Continental European Model* – one wholesale market (day-ahead/forward) for each bidding zone; or
- *The Nordic Model (NordPool)* – one wholesale market covering all bidding zones with a virtual system price for all bidding zones as reference price for forward contracts and day-ahead price for each bidding zone.

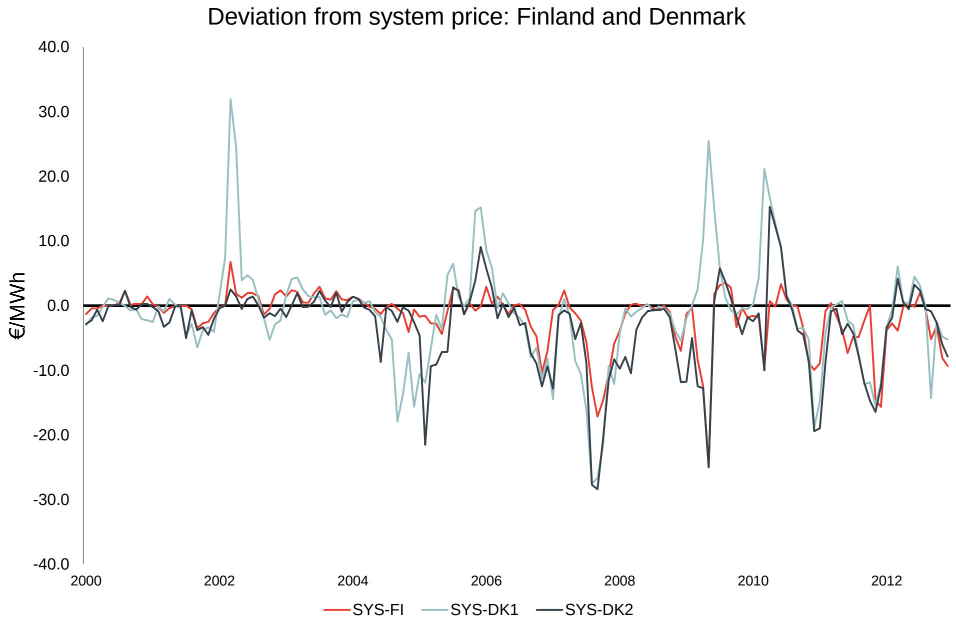
In the *Continental European Model* the size of the spot and forward market will be divided into several bidding zones resulting in a reduction of the size of each market (compared to the integrated market). Hence, we would expect an adverse effect on market liquidity in the individual bidding areas caused by:

- *Reduction in market participants* – Power exchange market exhibit economies of scale, market participants are attracted by potential counterparties and vice versa.
- *Reduction in the depth of market* – The reduction in market participants will feed back into the depth of the market, leading to a reduction of liquidity in the forward market.
- *Market power* – The smaller the bidding zone, the higher will be the potential for the exercise of market power in the spot market. This could result in distorted market prices which would in turn reduce the confidence in the price signals from the power exchange. We also discuss issues of market power in a separate section.

In order to pool market participants at least in the forward market the *Nordic Model* simultaneously calculates a system spot price, which is the relevant settlement price for all forward contracts. This system spot price can and does differ from the zones spot prices thus resulting in basis risk in the market. The basis risk stems from the divergence between the price that a participant pays or receives in the spot market – the price in each bidding zone – and the price at which its financial contracts are settled – the system spot price.

We note that these differences may be large and non-systematic which can be illustrated by NordPool price data for Denmark and Finland compared to the system spot price (see **Figure 7**). For example, the area price in Finland in 2013 and 2012 was on average -12% and -17% below the system spot price. The area price for Denmark (DK1 and DK2) in 2013 and 2012 was on average -11% (-12%) and -16% (-20%) below the system spot price. Hence, basis risk can be substantial.

Figure 7. Difference between area and system price for Denmark and Finland



Source: NordPool

- **"Simple" hedging of this basis risk is not practically possible, because the basis itself is not sufficiently liquid** – This confirms our view that complete markets remain a hypothetical illusion.

  As a consequence, area price risk management has become an important part of risk management strategies, especially for retailers and customers in the NordPool countries. The instruments in the NordPool market to hedge basis risk are *Contracts for Differences (CfD)*. A CfD is a forward contract financially settled according to a difference in prices, in this case the difference between the Area Price and the Nord Pool Spot System Price. At the time of trading the market price of a CfD reflects the market's prediction of the price difference during the delivery period. CfD theoretically provide the possibility for a perfect hedge even when the markets are split into one or more price areas.[18] However, the experience with CfDs is not unambiguous. There is still limited liquidity in CfD contracts and market participants complain that the "insurance premium" for CfD contracts to be unjustifiable in relation to the expected magnitude of the area price risk. For all CfD contracts there is a limited number of sellers and the participation by financial traders is small. Hence, the area price risk is in many cases not

18 NordPool, *Trade at Nord Pool ASA's financial market*, 2010.

hedged and removed and is instead borne by market participants. Additionally, the area price risk is often borne by customers through variable price contracts.[19]

Another option to hedge basis risk are *Financial Transmission Rights* (*FTR*). FTRs are instruments that provide their holders with a stream of revenue derived from the differences in nodal – bidding zones – prices that occur when transmission limits bind. Introducing a system of FTRs is complex. A crucial issue involves the – initial – allocation of FTRs. This could involve an auction/tender process or an administrative allocation method.

We conclude that hedging basis risk becomes a main challenge for the wholesale market, where the outcome on market liquidity for this market segment is uncertain.

- **Basis risk from smaller bidding zones has an adverse effect on retail competition** – In the case of the creation of several smaller as opposed to one larger bidding zone, retailers have to adjust their electricity procurement strategies taking into account the price difference between bidding zones in their procurement strategies. Hence, procurement will become more complex encompassing new hedging instruments – if available. In the worst case, the higher costs may drive (some) retailers out of the market or prevent retailers from entering the market in the first place. At minimum, higher transaction cost in wholesale markets will also increase retail prices. We also return to this issue in the context of market power.

Suggestions for further analysis

- **Assessment on the impact from reconfiguration of bidding zones on market liquidity requires detailed disaggregated price and volume data** – As discussed above, indicators for market liquidity should be derived for different trading periods in the respective countries/markets. Hence, disaggregated data are necessary for
  - Prices and volumes;
  - OTC and power exchange; and
  - intraday, day-ahead and forward markets.

  Prices and volumes have to be extracted from brokers for the OTC market, which may be difficult. For example, we note from our analysis that

19 For a detailed survey on the NordPool financial market see: NordReg, *The Nordic financial electricity market*, Nordic Energy Regulators, Report 8, 2010.

Bloomberg often reports only price but no volume data for certain products and countries.

3.3 Market power

ACER consultation document

2. 6 Market Power (p.8) – The relation between market power and the size of the bidding zone is not straightforward. On the one hand, it may be argued that the larger the bidding zone, the lower the market power that any market player may exert in the day-ahead market, due to the increased liquidity in the bidding zone. On the other hand, it may be argued that due to a better appraisal of network congestions and the increase of transmission capacities, the reduction of zone size allows for an increase of cross-zonal competition. … Competition in redispatching is weaker than competition in the day-ahead market coupling.

In the case of smaller zones or nodal pricing, remedial actions are more likely replaced by day-ahead market coupling, solving the congestion based on the bids from all generators and thus the generator with locational market power is faced with more competition in solving the congestion.

- **Large bidding zones are the most efficient mean to deal with market power** – ACER states a trade-off between market power in the day-ahead and the redispatch market, indicating that lower market power on the day-ahead market may come at a price of higher market in the redispatch market. We believe, this argument may not fully grasp the reality of the market:
  - Any nodal dispatch approach – including redispatch – raises a local market power issue – Whenever a redispatch need arises, market power issues are latent. This is because with optimal redispatch, the TSO will consider the effect (leverage) of a redispatched unit on the congestion as well as the specific cost of that unit. The lever of "redispatch effect" tends to outweigh the importance of the cost of a different plant. Therefore, by knowing the network topology and locations of possible congestions, plants that can help relieve congestion know of their pivotal role and through this enjoy some degree of market power.
  - Redispatch does not fundamentally change with smaller bidding zones – As discussed in **section 3.1** a redesign of bidding zones will not make redispatch needs obsolete. In fact, the specific redispatch need may not change at all. Whether it does is an empirical question that can only be answered location-specifically. Therefore the hypothesized gain in the reduction in market power in redispatch by the creation of smaller bidding zones is not clear.

- Market power in redispatch affects the individual plant, market power in the traded market the entire bidding zone –
  - Moreover, market power in redispatch may be of relatively inferior concern. Because redispatch remuneration is node or plant-specific the exercise of market power would benefit a single plant, but would not raise the market price in the total bidding area. In other words, a market power issue would be confined to a small part of the market. Moreover, a regulation of the redispatch process is feasible and acceptable if it helps ensuring efficiency of the much larger forward and spot markets.
  - By contrast, market power in a full bidding zone could lead to increased prices in the full zone and, thereby, to a significant burden on consumers.

  Therefore the trade-off between less redispatch market power in smaller areas (provided there was a redispatch reduction at all) and higher market power in larger areas may not be as simple as implied in the statement in ACER's consultation document. Logic suggests that market power in the traded market in smaller bidding zones may become a real concern while redispatch market power is more confined and may be solved through some regulatory rules.

- **Any cost-benefit analysis of bidding zone design should consider the impact of market power on market liquidity** – In larger bidding zones market participants have trust in the depth of the markets and this fosters market liquidity. Reducing the size of the bidding zones may create market power issues and may reduce the trust in the wholesale market, as such, if market participants fear that market prices may in part be driven by some strategic behaviour rather than fundamental factors. This could adversely impact market liquidity with the negative effects considered in **section 3.2**.

- **Larger bidding zones will favour competition in the retail market** – The economics of the retail business is critically driven by economies of scale. There are a number of costs associated with entering this market, and then expanding to reach scale. These include investment in IT systems and call centres and the costs associated with building a brand and acquiring customers. Because customers' willingness to switch their suppliers tends to be low, new entrants need a big market potential to acquire a critical mass of customers to break even.

  In a larger bidding zone retailers do not need to hedge against locational price differences (between areas in which the retailer buys and sells electricity). As discussed in **section 3.2**, hedging against locational price differences will at best impose an additional transaction cost and will at worst be infeasible if liquidity for hedging products is too low. This increases the cost of retailers and will make entry to (or continuation in) the market less attractive. Hence, larger bidding zones tend to reduce market entry barriers in the retail market and makes the market more contestable. This will put pressure on incumbents' behaviour and the retail price level. The main advantages of larger bidding zones for retailers are:

- Liquid wholesale market along delivery terms which allow retailers to optimise their procurement strategy for electricity; and
- larger potential customer base which allows reaching economics of scale within bidding zone. Hence, building up a critical customer base is possible without being exposed to basis risk.

- **Argument by ACER also should consider the practical circumstances** – ACER in its discussion seems to imply that it is not clear *a priori* whether smaller bidding zones lead to more or less competition in the traded market. ACER's argument is that smaller bidding zones would help free up interconnector capacities for trade. This additional trade potential could then help undermine market power by incumbents and thereby counterbalances an adverse effect of increasing market concentration in smaller bidding zones. However, as our discussion in **section 3.1** on market efficiency showed, already the assumption that smaller bidding zones allow using more interconnector capacities on the outer borders of the region under consideration is not generally founded – at least not as long as commercial trading constraints had not previously been moved to outer borders to relieve an internal physical constraint (as had been suspected in the case of Sweden). As our discussion in **section 3.1** showed (if internal congestion had previously been managed through redispatch), the creation of smaller bidding zones does not significantly affect the import potential into the region affected by the redesign. In this case, creating smaller bidding zones would increase market concentration and this would not be compensated by more import capacity becoming available.

3.4 Investment signals and risk mitigation

ACER consultation document

2.5 Investment signals – The configuration of bidding zones impacts economic signals for investments. The more the bidding zones configuration reflects the physical network constraints, the more efficiently the congestion rents provide economic signals for cross-zonal network development and the price signal for generation investments.

In this section we separately consider aspects of network investment and plant investment. We also discuss the potential impact on locational decisions for demand.

Signals for network investment

- **The key barrier for transmission investment is permitting procedures and not a lack of economic signals** – In theory, bidding zones with electricity price differences create investment signals for investors into transmission lines by making transparent congestion rents and providing signals where to invest.

  However, the main congested hotspots in the European network are well known to the TSOs anyway and also with greater geographic accuracy than could ever be established through the zonal design of bidding areas. This means that TSOs already have the knowledge where to invest under the current configuration of bidding zones. It is not a lack of economic signals which prevents necessary investments but the main barrier is the significant lead time for and the increasing public resistance against transmission projects. The EU Commission addresses this challenge in relation to transmission investments with cross-border impact via the Energy infrastructure package. Investment projects may be classified as Project of Common Interest which benefit from *inter alia*

  - streamlining of permit-granting procedures to reduce significantly the lead time for projects of common interest and increase public participation and acceptance for the implementation of such projects; and

  - facilitating of the regulatory treatment of PCIs in electricity and gas by allowing the allocation costs to match the distribution of benefits and ensuring allowed returns are in line with the risks incurred.

  The reconfiguration of bidding zones, e.g. into smaller units, may jeopardize attempts to streamline the permitting procedure on a European and national level. This is because authorities may argue that – with smaller bidding zones

– market forces are at work sufficiently handling congestion management. This might lead to the administration of scarce network resources rather than the optimal development of the European grid.

- **Turning congestion costs into congestion revenues (which is a natural consequence of introducing smaller bidding zones) may have an adverse effect on transmission investments** – If congestion arises in a bidding zone, the transmission system operator solves the congestion by redispatching power plants to reduce the load flow on the affected congested line. Resulting redispatch cost in the first instance constitutes a cost to the TSO, which depending on the regulatory design may be fully or partly passed to network users. By splitting the bidding zone along structural congestion, different electricity prices will prevail in the resulting bidding zones. The difference in prices will reflect the congestion rent. In the case of auctioning the scare transmission capacities between the bidding areas, congestion costs turn into congestion revenues allocated to the regulated TSO. These revenues must be used either for relieving congestion by investments or for lowering network tariffs.

  However, we note that turning congestion costs into congestion revenues may have an adverse effect on transmission investments, if a TSO worries less about congestion revenues than congestion costs. For instance, even if either congestion costs or revenues were completely neutralised through regulatory adjustments of allowed network revenues , it may still be preferable for the TSO to obtain congestion revenues in order to lower network tariffs than to pass on congestion costs resulting in higher tariffs.This may have the adverse effect – if unaddressed – that incentives to fundamentally relieve grid congestion by grid investments may be lower in a regime with smaller bidding zones than with wider bidding zones.[20]

Signals for power plant investment

- **The degree of the impact from price signals depends on generation technologies** – Generation technologies can be differentiated into:
  - *Technologies with free location choice* – Generally the locational choice for gas- and coal-fired power plants is free due to the possibility of transporting and storing the primary fuel. Hence, investors can include the location of the plant into their economic optimisation problem.

20 This should not be mistaken in the sense that TSOs would have a general incentive to favour a reconfiguration towards smaller bidding zones. In fact, current experience in Germany shows that TSOs are ready to accept notable operational effort and develop related processes in order to manage intra-zonal congestion within the existing zone configuration.

- *Locationally bounded technologies* – Generation from renewables (especially from wind and hydro power) and lignite is restricted to certain locations. The transportation of lignite may be technically feasible, however, prohibitively expensive. The same may hold true for a wind power plant located in an area with low wind availability, where the average total costs will more than double due to lower utilisation factors.

The investment signals induced by regional electricity price differences in smaller bidding zones will be one of many factors that investors consider in their location decision. For location-bounded technologies, these other factors will outweigh the importance of regional price differences. Therefore regional price differences (and smaller bidding zone design) will only ever have a partial effect on investment decisions.

- **Investment signals from electricity prices for generators are only one of many decision criteria even for plant that could be located flexibly** – A more fragmental bidding zone design would tend to lead to a more regional differentiation of electricity prices revealing information about the scarcity of generation capacities. Theoretically, these price signals should steer locational decisions from generators and load in the right congestion relieving direction.

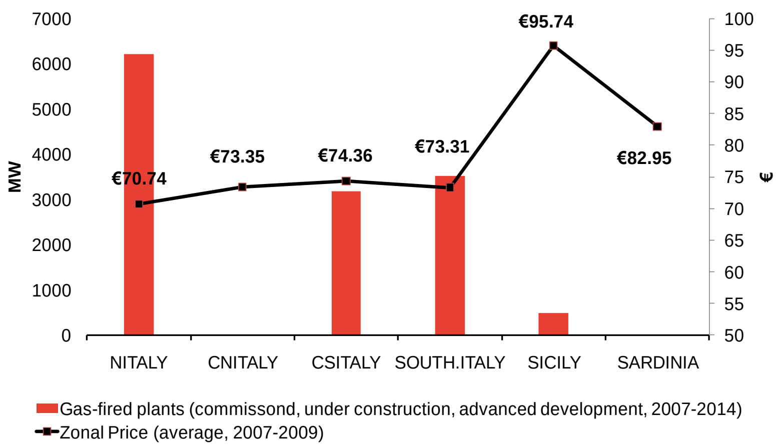
  However, whether investors can react to electricity price signals – by relocating plants – will depend on the importance of additional factors in the respective bidding zone, e.g.:

  - *The need for additional plant capacity* – locational steering will only realistically arise if there are imminent plant investment decisions;
  - *Availability of cooling water* – e.g. coastal or river sites;
  - *Grid access* – in the case of greenfield investments distance to next grid access point influences connection charge;
  - *Local approval process* – support and acceptance of local authorities and population influences investment costs and planning restrictions in certain areas;
  - *Greenfield vs. Brownfield* – usage of existing site brings synergies and reduces burden on approval; and
  - *Fuel transportation cost* – e.g. proximity to harbour facilities.

  The investment behaviour in the Italian generation market with regard to gas-fired power plants may serve as a good example for the interplay of various locational factors. The focus on gas-fired power plants is appropriate as this technology allows relatively free location choice and the majority of new-built and planned conventional power plants for the period 2007-2014 were gas-fired. The main findings for Italy are:

- The overall price level in Italy indicated a need for additional generation capacities and attracted investors into the market.
- Within Italy the impact of price differences in the six price zones on locational decisions were however not unambiguous. Although the average electricity price for 2007-2009 for the North Italy (NItaly) price zone was the lowest most of the new-built and planned gas-fired plants in 2007 to 2014 are located in this zone. North Italy is followed by Central South (CSITALYI) and South Italy (SOUTHITALY). The reason for low investments in Sicily and Sardinia may be that because both regions are islands, the price would have fallen by too much if a plant had been built.

Figure 8. Italy Price zones – New built, under construction, advanced development gas-fired plants (2007-2014)



Source: Platts, Frontier Economics

- **Price signals only work if investors in generation are exposed to market prices** – The current new-built capacity in Europe mainly stems from renewables, in particular wind. To a large extent the reward for renewables comes from feed-in tariffs or other support schemes. This leads to a decoupling of revenues from electricity market prices. Thus, for investors into renewables other locational factors instead of the electricity market price will dominate their investment decisions. This limits the locational steering effect from bidding zones with respect to renewables, which are currently the main new-built technologies. If the coastal area overlaps with a low-price bidding zone, indicating less need for new generation capacities, the low market prices will not change the investment decision of investors in renewables.

- ***Inter-bidding zone* locational signals by differing electricity prices may not be precise enough** – There are no *intra-bidding zone* locational signals from electricity prices in a zonal pricing model. However, in order to optimise a congestion-relieving power plant the locational signals from bidding zones may not be sufficient and more precise locational signals may be desirable. Hence, there may be a need for supplementing the locational signals from zonal electricity prices with additional instruments and redispatch is still required.

- **Feedback with market liquidity needs to be taken into account** – Firstly, if a narrowing of bidding zones reduces liquidity the availability of forward trades may also fall and plant investors would lose important price signals that allow them to make informed investment decisions in the first place (in this instance a theoretically better locational signal may be sacrificed for planning certainty of investors). Secondly, it is questionable whether plant investors would make plant-location decisions based on shorter-term regional price differences. This concern is particularly relevant if narrower bidding zones lead to a drying-up of market liquidity in forward markets.

- **A stable and predictable investment climate is crucial for long-term investments in generation** – The mere threat of a regular reassessment and potential reconfiguration of bidding zones may undermine the credibility of forward products, as these are tied to the existing configuration of bidding zones. This leads to a fundamental weakening of hedging opportunities, thereby undermining investment incentives. Consequently, the – even potential – instability of the bidding zone configuration may contradict the position[21] of the European Commission that a functioning market should deliver appropriate generation investments. In addition, it is worth noting that the current discussion on the reconfiguration of bidding zones overlaps with other political hot topics with regard to energy policy, e.g. potential adjustment of renewables subsidy regime and market design by including capacity market, future climate policy, which all have a substantial impact on the overall investment climate in the energy sector.

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21 "Making the internal energy market work", COM(2012) 663 final, Brussels, 15.11.2012, p. 12f (http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=CELEX:52012DC0663:EN:NOT)

Signals for demand

- **The degree of the impact from price signals depends on customer type –** It is necessary to distinguish customer types:
  - *Small customers* – Households, commercial and small/medium sized industrial customers; and
  - *Large customers* – Large industries.

  For households the electricity bill is only a small part of total expenditure. Furthermore, commercial and small/medium sized industrial customers, for whom electricity prices constitute an important cost, typically compete with firms in the same bidding zone and are therefore exposed to similar prices. Hence, we do not expect that small customers will change their location based on lower prices in a bidding area, because other locational factors dominate the price of electricity.

  The competitive pressure for large customers may be different. They face competition at an interregional and / or global level. Hence, large energy intense industries take into account the electricity bill as one important and substantial cost component, which has to be competitive in national and international comparison. For these customers, locational signals from electricity prices play a relevant role in location decisions.

- **The risks facing large customers are similar to those for generators –**
  - volatility of the market signal; and
  - long-run reliability of the market signal.

  Large customers will face more volatility in prices in smaller bidding zones. One strategy to cope with this is to enter into long-term contracts and reduce dependence on short term price signals from the wholesale market.[22] However, long-term contracts will typically include a price formula linked to a reference price. This price might be an average – to cancel out a large degree of volatility – price specified for a certain location in the bidding zone. In this way large customers will be exposed to regional electricity price signals even if they procure power through medium to long term contracts. Whether this affects their locational decisions (to relieve congestion) depends on

  - the importance of electricity prices to the business; as well as

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22 This has a negative effect on the number of market participants in the wholesale market and on market liquidity.

- other factors, such as site availability, etc.

Moving borders between bidding zones can jeopardize the value of the long-term contract, if the reference price moves into a high-price bidding zone. Hence, changing bidding zones increases the complexity of electricity procurement for – all – customers, which reduces the benefits from locational signals.

Suggestions for further analysis

- **When assessing the impact from electricity price signals on investments in generation and transmission ACER may apply the following principles** –
  - *Empirical analysis of trade-off between transporting electricity and primary fuels* – locational signals for generators steering their locational decision should only be applied if the transportation costs for electricity are higher than the transportation costs of primary fuels, e.g. gas and coal. If this is not the case then investments into transmission lines to transport electricity to the load centres is more preferred than bringing generation capacity to load centres.
  - *Empirical analysis of the overall need for generation capacities* – local investment signals for generators will only fulfil the expected benefits if the market is short on generation capacities. If there is over-capacity in the market as a whole slightly higher electricity prices in a bidding zone will not induce additional investments into generation. However, we note that price signals from different bidding zones may have an impact on decommissioning decisions to reduce over-capacities.
  - *Empirical analysis on the role of renewables in the current (future) generation mix* – local investment signals for generators will only fulfil the expected benefits if investments in renewable generation react on it. If the expansion of renewables is a political goal supported by non-market price-related subsidy schemes then different bidding zones and prices inside national borders will have only a limited – if at all – effect on locational decisions for generation.

3.5 Transaction costs for reconfiguration of bidding zones

- **Reconfiguration of bidding zones comes at a cost** – The costs can be grouped into two categories. By costs for primary measures we understand measures which are directly related to the change of the market design. Usually they follow a sequential path:

Reconfiguration of bidding zone – economic evaluation

- Changing the legal framework;
- deciding on the new market design;
- definition of new bidding areas and transmission capacities between bidding areas;
- allocation of new transmission capacities between bidding areas (day-ahead, month-ahead, year-ahead); and
- IT costs for market participants (e.g. power-exchange, traders, suppliers, etc.).

By costs for secondary measures we define measures which are the consequence of the institutional change:

- New definition of balancing zones resulting in necessary adjustments in IT systems and interfaces between market participants in the new control areas;
- new valuation of contracts/positions; and
- costs for renegotiation of power contracts if the reference location of price changes or is not accepted by contract parties any more.

The costs for renegotiation of power contracts can constitute a significant burden on smaller market participants. Moreover, these costs are not only restricted to market participants in the affected bidding areas, if market participants outside the bidding area used the market price as their respective reference price.[23]

- **In addition, reputational effect has to be taken into account** – Besides the monetary transactions costs, there are qualitative transaction costs, as well, e.g.:
  - Market participants might lose confidence in the market, if they do not understand why a functioning market design is changed.
  - Market participants in countries with less-developed markets will lose confidence in the reference price of the market that changes its design. This might hamper the slowly growing wholesale markets in

[23] In a recent report RedPoint (2013: 61) wrote: "As noted above in the liquidity analysis, producers seem commonly to hedge part or most of their Dutch positions in Germany. One producer stated that it mainly uses the German market and only sometimes hedges in the Netherlands. The other producer referred to the Netherlands as the first point of call for hedging Dutch positions but noted that it is increasingly necessary to hedge in Germany or Belgium because of liquidity." (RedPoint, *Long-term cross-border hedging between Norway and Netherlands*, A report for the Netherlands Competition Authority, Office of Energy Regulation (NMa) and the Norwegian Water Resources and Energy Directorate (NVE), March 2013).

these countries, with a negative effect on European electricity markets as a whole.

- **Lead time for reconfiguration of bidding zones should be aligned with term structure of forward markets** – The leading principle governing the reconfiguration of bidding zones should be that the impact on the existing market institutions and contracts in wholesale and retail markets are as small as possible. A good indicator for the minimum lead time is the term structure of the forward market, i.e. how many years out forward contracts are traded. The alignment of the lead time of a redesign to the term structure of the market reduces uncertainties of all market participants to a minimum. Additionally, it allows market participants to progressively adapt to the new market design and settle their existing power contracts. In the retail market it allows retailers to adapt their contracts with customers, as well, dampening the negative effect from annual fixed price contracts.

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