

European Experiences on Power Markets Facilitating Efficient Integration of Renewable Energy

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PREFACE

One of the most important steps towards China's green transition of the power sector is China's power market reform. The experiences from Europe show that the establishing of efficient, transparent and liquid short term power markets with clear price signals is fundamental for enhancing the flexibility in the power system. The eight pilot areas for short term power markets announced in 2017 are major steps in China's power market reforms. In each of the eight areas, local stakeholders are engaged in the planning and design of short term markets. Research projects, trainings and workshops on the design and implementation of pilot markets accompany the pilots and facilitate capacity building and knowledge exchange between the stakeholders in the relevant provinces.

This report has been prepared by the Danish TSO Energinet and the European Commission's DG Energy and follows up on a workshop facilitated by the Danish Energy Agency (DEA) and Electric Power Planning & Engineering Institute (EPPEI) in January 2018 in Beijing, where key stakeholders from the national and provincial level from some of the pilot areas and the authors of this report discussed challenges and opportunities when moving towards a market-based electricity system. The report describes the European experience of integrating electricity markets, and focuses specifically on the issues of transmission capacity allocation, the co-existence of long-term contracts and short-term markets, and market liquidity, which were raised during the workshop. As such, the report aims to contribute to the debate on market design in the eight pilot areas by providing examples from the European experiences during the process of establishing the European internal electricity market. DEA's and EPPEI's cooperation on the 'China Thermal Power Transition program' supports China's National Energy Administration's (NEA) power market reform under the Sino-Danish cooperation between NEA and the Danish Ministry of Energy, Utilities and Climate.

1. INTRODUCTION

China has set an objective for establishing a country wide power market in 2020. To succeed, a number of challenges have to be addressed.

Europe has developed an electricity power market during the last 20 years on a step-by-step basis but with a common target model as the objective. The development has been through the combination and incremental development of national and regional solutions.

This report gives an overview of a number of the European challenges towards the common target model and both the successful and non-successful experiences. The Chinese and European energy system, institutions and regulatory framework are very different, but it is the assumption that the general challenges in establishing a common market are to some degree the same.

The report will present four different topics important for the transition to well-functioning and efficient electricity markets. Chapter 2 provides an introduction by describing the overall objective in the European Common target model and the development of regulation on the European level. Chapter 3 describes two important steps in the history of European market coupling and the challenges that were experienced. First the connection of power markets with explicit auctions is described, followed by the use of the implicit auctions with coupled markets. Chapter 4 deals with the challenges related to TSO income, i.e. tariffs, congestion income, and existing contracts on the use of the interconnectors. Finally, Chapter 5 discusses the experiences with the transition from bilateral long-term power contracts to the establishment of power exchanges and how to increase market liquidity.

2. EUROPEAN UNION COMMON TARGET MODEL

The opening of energy markets were discussed already in the 1980's alongside free movement for goods, services, capital and people by 1992. For electricity and gas the process took longer, the legislation passed in 1996 and the markets were opened in 1999 and 2000 respectively.

Markets were opened in several stages starting in 1999 for big customers and finalised in 2007 for all customers. Basic choices for the European electricity markets were:

- Unbundling of grid activities (considered being natural monopolies), tariffs to remain regulated, from generation and supply, subject to competition thus without price regulation.
- Zonal market design: electricity price is the same in the whole zone. Most countries considered themselves as their own price zones (some countries with several price zones and some countries with merged zones were established).

A further step was the opening of cross border trade to competition, explained in Chapter 3 "Coupling of power markets".

During the first years of opening the markets, it became clear that different ways of implementing the electricity market in Member States would prevent further integration of markets. A need for a target model became evident. The process to agree on a target model was launched in the Florence regulatory forum in 2006 and it was finalised in 2009. The work on the target model was led by the National Regulatory Authorities, with active participation of all stakeholders. The main elements of the target model are:

- Forward markets with prices linked to day-ahead spot markets is the main hedging tool for electricity trading.
- Long-term (Yearly, monthly) cross border capacity is sold by TSO through auction through financial or physical products for hedging the cross-border position of energy traders.
- Cross-border trade optimisation based on day-ahead market coupling in which all re-remaining cross-border capacity is allocated together with the calculation of prices in each price zone.
- A pan-European intraday platform "XBID" allows cross-border intraday optimisation using remaining capacity in the grid.
- Final cross-border optimisation through TSOs exchanging balancing energy using remaining capacity in the grid.

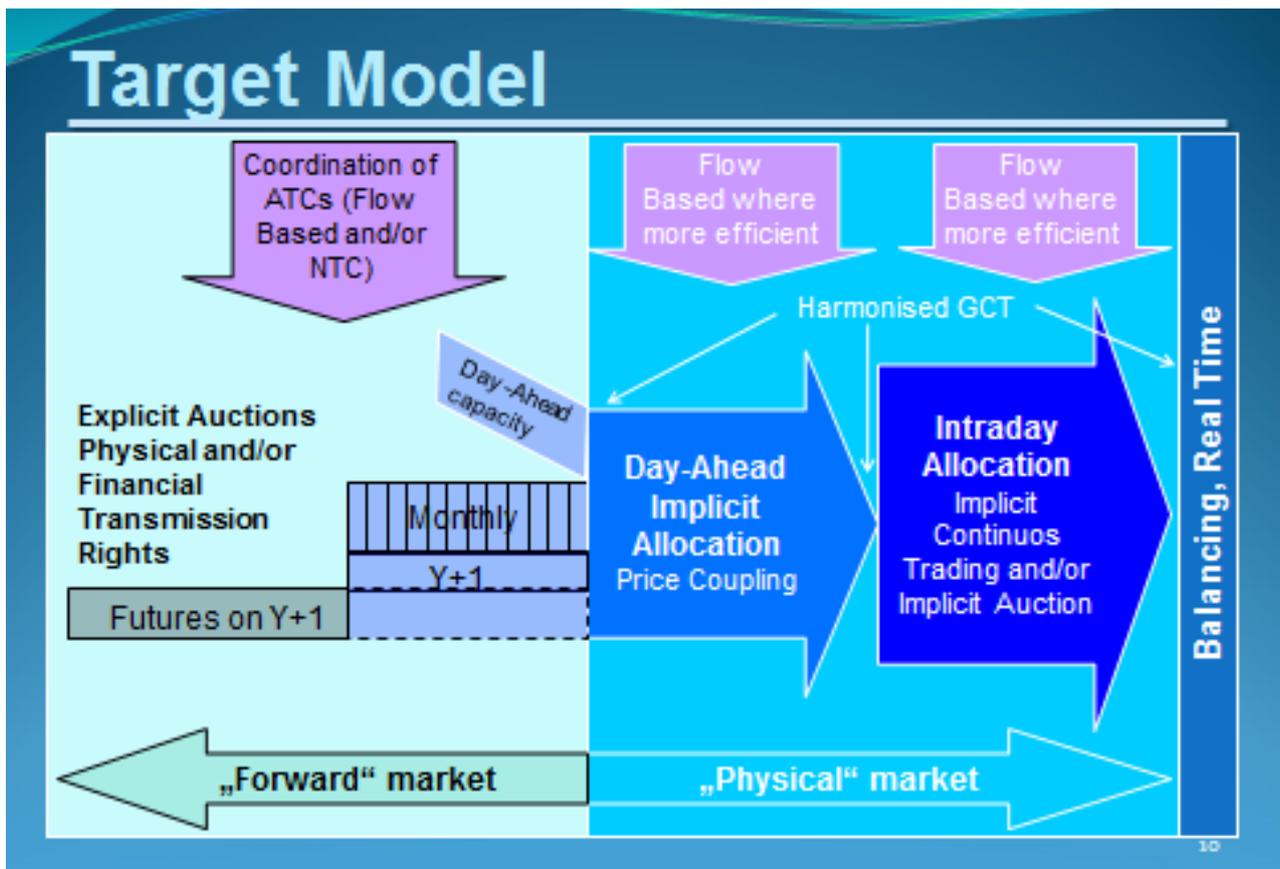


Figure 1. EU-electricity market target model (EREGG slide in the Florence regulatory forum in June 2009).

The work regarding the target model continued in the preparation of network codes, a new tool to provide EU-wide detailed rules. The process of making network codes is explained in the following section.

2.1. HARMONISATION

The so called third energy package adopted in 2009 included two important provisions regarding the EU electricity markets:

- New institutions: Agency for cooperation of energy regulators (ACER) and a European Network of Transmission system operators (ENTSO-E)
- A new process to make binding EU-wide rules, “network codes”, on electricity markets

The areas in which the network codes apply can be split into three broad families:

- Connection Network Codes
- Market related network codes
- System Operation Networks Codes

Connection Network Codes

The Connection Network Codes are designed to align the rules for connecting to networks for parties of all sizes. This family includes three networks codes:

1. Requirements for Generators (RfG)¹;
2. Demand Connection Code (DCC)²; and
3. High Voltage Direct Current Connection Code (HVDC)³.

These codes are very similar in terms of requirements and collectively cover the different sorts of parties connecting to the power system. They also apply to very small parties (as small as 0,8 kW), because the behaviour of small units, especially given their total share, is increasing so significantly that they can play an important role for example in case of large system disturbances.

Market Related Network Codes

The Connection Network Codes are designed to align the rules for connecting to networks for parties of all sizes. This family includes three networks codes:

Three network codes are dealing with the cross-border aspects of the market design. These broadly mirror the timescales in which power is traded:

1. The Forward Capacity Allocation (FCA)⁴ network code deals with transmission capacity allocation in forward timeframes (longer than day-ahead) and establishes a single allocation platform for allocation of forward transmission rights.
2. The Capacity Allocation and Congestion Management (CACM)⁵ network code covers the design of cross-border day-ahead and intraday markets, the method for calculating cross-zonal capacity, the delineation of bidding zones and the governance arrangements for the market (which covers the respective roles of power exchanges and TSOs).
3. Electricity Balancing (EB)⁶ network code deals with the design of cross border balancing markets.

Collectively these codes implement the so called 'target model' for European markets. This was a model developed and endorsed via a prior process in order to achieve a common understanding and support among all stakeholders.

1 http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=OJ:JOL_2016_112_R_0001

2 http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv:OJ.L_.2016.223.01.0010.01.ENG&toc=OJ:L:2016:223:TOC

3 <http://eur-lex.europa.eu/eli/reg/2016/1447/oj>

4 http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv:OJ.L_.2016.259.01.0042.01.ENG&toc=OJ:L:2016:259:TOC

5 <http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32015R1222>

6 https://ec.europa.eu/energy/sites/ener/files/documents/informal_service_level_ebgl_16-03-2017_final.pdf

System Operation Network Codes

The two system operation network codes are intended to promote closer interactions between TSOs, particularly within synchronous areas. These rules build heavily on those which had already been in place in each of the European synchronous areas for many years; using, in particular, the UCTE⁷ handbook as a model.

- The System Operation (SO) ENC⁸ focuses on operational security, operational planning and scheduling and load frequency control and reserves; and
- The Emergency and Restoration (ER) ENC⁹ deals with procedures in an emergency.

Additionally, the legislation provides for harmonised tariffs paid by generators to avoid distortions due to different charges paid in each price zone. Also, a mandate to make rules on compensation for transits, remunerating the ones who have to host transit flows from neighbouring countries, was provided.

7 UCTE: Union for the coordination of Transmission of Electricity, covering the TSO's of central European synchronous area

8 <http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32017R1485>

9 https://ec.europa.eu/energy/sites/ener/files/documents/nc_er_ener_vs_13_ecbc_on_24_25-10-2016finalasvotedfor_publication.pdf

3. COUPLING OF POWER MARKETS

3.1. INTRODUCTION

A prerequisite for coupling neighbouring power markets is to allow third party access to the interconnectors through introducing market-based access to interconnectors. In Europe, two methods have been identified:

- Explicit allocation of capacity (transmission capacity is allocated to the market separately and independently from the marketplaces where electrical energy is traded)
- Implicit allocation (capacity and energy are auctioned together)

There may also be a need to ensure that long-term contracts blocking the capacity of interconnectors are “opened”. Experiences from Europe on how this has been tackled can be found in Chapter 5.

3.2. EXPLICIT ALLOCATION

3.2.1. FIRST COME, FIRST SERVE

A quick method to introduce third party access to interconnectors could be to give third party access by selling capacity contracts to those who ask for access. With the method of “first come, first serve”, the interconnector capacity owner, in Europe typically the TSO, sells capacity contracts according to a fixed price list. This could e.g. be annual, monthly, daily or even hourly capacity.

The method should in practice only be used as a temporary solution while opening of markets and more market-oriented methods are under development. The reason is that “first come, first serve” could give incentive to capacity hoarding, de facto closing the market/interconnector for competition.

In Europe, it is also no longer legal according to European legislation to ask for a specific cross-border fee to transport electricity across borders as this discriminates imports of electricity from other countries.

An example of “first come, first serve” is the Kontek interconnector between East Denmark and Germany, where the methodology was used in the very early days of liberalisation in 2000 and 2001. When power markets were introduced in Germany in 2001 they had already been introduced in East Denmark, and the demand for capacity increased fast. In this case “first come, first serve” did not make any socio-economic sense, as the reservation of capacity did not reflect the buyers’ willingness to pay.

Instead, it was decided to split the capacity equally between all market players that had asked for capacity on a monthly basis until an auction had been developed and implemented. Also, the principle of equal split did not have any relation to the willingness to pay, as the capacity price

was fixed according to the price list. Nevertheless it was seen as a better temporary solution than “first come, first serve” when developing a more market-based system.

Thus, in practice, coupling of markets must include auctions of interconnector capacity to ensure efficient use of interconnectors.

3.2.2. EXPLICIT AUCTIONS OF CAPACITY

Explicit auctions are considered a simple method of handling the capacity on the international interconnections in Europe. They can be implemented promptly, and while taking time to develop more efficient solutions, such as market coupling based on implicit auctions, which is described in the following section.

In an explicit auction system, the capacity is normally auctioned in portions through annual, monthly and daily auctions. In the beginning it was normally the TSOs involved on an interconnector that operated the auction. For capacity on the West Danish-German border, it was the German TSO that developed and operated the auction tool. However to make it simpler for market players, who very often were active in many different countries, the TSOs decided to develop common auction platforms¹⁰.

The rules for explicit auctions have been harmonised over the last years. On October 2nd 2017, the Agency for the Cooperation of Energy Regulators (ACER) approved harmonised allocation rules¹¹. The price setting is based on the marginal pricing principle where a uniform price for all capacity is calculated. The example below from the capacity auction of monthly capacity for the French-Spanish border shows an example where 770 MW are auctioned and where the actual demand curve results in a settlement price of 4.02 €/MWh, meaning that all buyers with a willingness to pay above 4.02€/MWh receive their demanded capacity at the unit price of 4.02€/MWh.

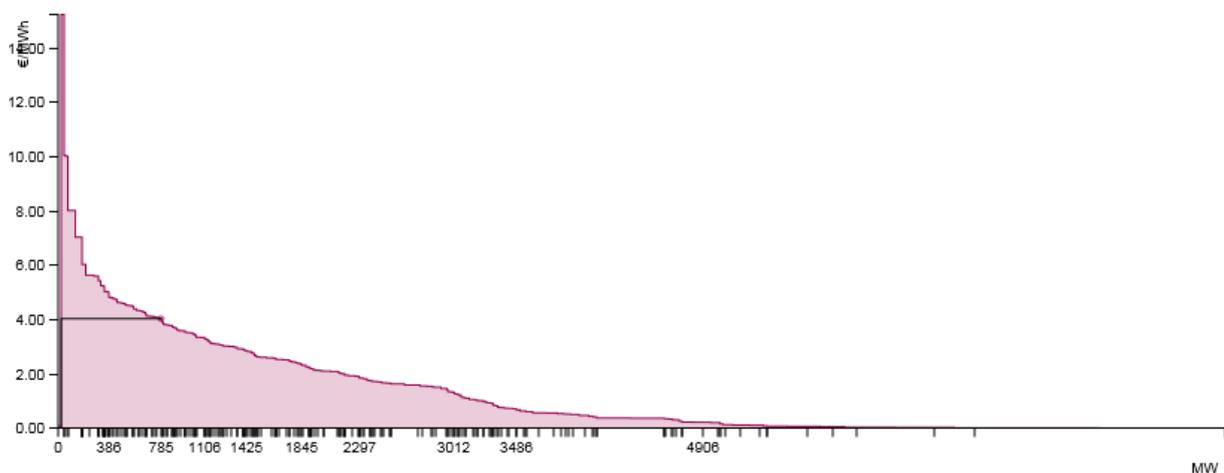


Figure 2. Example of price setting for monthly capacity (December 2017, French-Spanish border).

Source: www.jao.eu

In Europe, the annual and monthly capacity is normally sold as physical transmission rights (PTR). This implies that the customer that has bought interconnector capacity has the right to transport energy on the specific interconnector. Normally the capacity holder is obliged to nominate the

¹⁰ Two platforms were developed, CASC (Capacity Allocation Service Company) for Central West Europe and CAO (Capacity Allocation Office) for Central East Europe. In 2015, the two companies merged to become JAO (Joint Allocation Office). JAO is a joint service company of twenty TSOs from seventeen countries and is also responsible for other tasks on behalf of the TSOs, including project management in relation to market coupling operation.

¹¹ https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/ANNEXES_HAR_DECISION/Annex%20I_171002.pdf

use of the annual and monthly capacity to the TSO. The capacity that is not nominated is either lost (use-it-or-lose-it) or sold back to the TSO (use-it-or-sell-it). The unused capacity would then be added to the daily capacity auction, be it explicit or implicit auctions for the daily capacity. The holder of daily capacity is obliged to send the nominated capacity and, as a consequence of the so-called “netting”-principle, the capacity in the opposite direction can be increased by the same amount, as shown in the example below.

The following table gives an example of how the long-term PTR market interlinks with the day-ahead market. Here we assume that there is 1000 MW in total capacity available on an interconnector between the two market areas, A and B. The owners of the interconnector (normally the TSOs) decide to auction 400 MW of long-term PTR in both directions which means that there in principle is 600 MW left to the day-ahead market.

However, before the day-ahead market is running, owners of the PTR capacity are obliged to inform the TSOs if they intend to use the capacity by sending nomination plans. In the example given, the TSOs have received nomination plans of 200 MW for the direction Area A to Area B, meaning that the other 200 MW in practice have been given back to the TSO for the day-ahead market coupling (principle of use-it-or-lose-it or use-it-or-sell-it). In the other direction 0 MW was nominated, meaning that 400 MW is being given back to the day-ahead market. This means that available capacity for the day-ahead market in that direction is 600 MW + 400 MW = 1000 MW. However, as there is a firm nomination plan of 200 MW in the opposite direction, the actual available capacity can be raised by the same 200 MW (the netting principle), and still allows the total transported capacity to be 1000 MW or below.

| | Total Capacity | PTR | Remaining capacity | Nominated capacity | Capacity to Day ahead |
|------------------|----------------|-----|--------------------|--------------------|-----------------------|
| Area A => Area B | 1000 | 400 | 600 | 200 | 800 |
| Area B => Area A | 1000 | 400 | 600 | 0 | 1200 |

Table 1. Example on a Day-ahead market.

Daily explicit auctions were used in Europe until market coupling was implemented and is still used in some parts of Europe (in particular on the Swiss borders and the Irish interconnectors, as those two countries are still outside the market coupling). Where market coupling has been implemented, there no longer exist daily explicit auctions.

Daily explicit auctions are not optimal from a socio-economic point of view. Since the two commodities, transmission capacity and electricity, are traded at two separate auctions, there is a lack of information about the electricity prices when the capacity price is determined. The transmission capacity is priced on “guesses” on the value of capacity, which normally should be equal to the price difference between the neighbouring markets. Reality shows that these “guesses” are often wrong, and power flows from high price area to low price area as a consequence, i.e. in the “wrong” direction.

Calculations from Denmark before the daily explicit auctions on the border between West Denmark and Germany were replaced with market coupling show that the interconnectors were only optimally utilised in 30 pct. of the time, and that the electricity even flowed in the “wrong” direction in 24 pct. of the time.

Later estimations of socio-economic losses due to absence of market coupling on Irish and Swiss borders in 2015 and 2016 can be seen in the following figure:

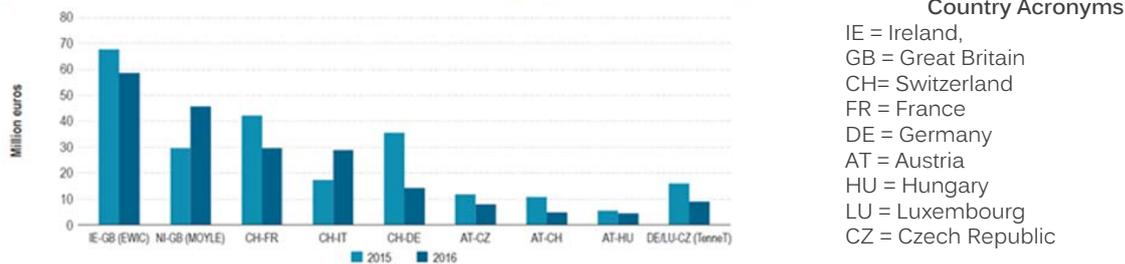


Figure 3. Estimated 'social welfare losses' in the absence of market coupling, per border - 2015-2016 (million euros). Source: ENTSO-E, NRAs, Vulcanus (2017) and ACER calculations.

The estimations show the same result as seen on the West Danish – German border. The absolute loss depends, among other things, on the size of the capacity and price differences.

3.3. IMPLICIT ALLOCATION

3.3.1. DEFINITION

With implicit allocation of the interconnector capacity, the day-ahead transmission capacity is used to integrate the spot markets in the different bidding areas in order to maximise the overall social welfare in the included markets. The flow on an interconnector is found based on market data from the marketplace/s in the connected markets. Thus, the auctioning of transmission capacity is included (implicitly) in the auctions of electrical energy in the market. Implicit auctions are today mostly known as market coupling.

3.3.2. MARKET COUPLING OF DAY-AHEAD MARKETS

Market coupling started in Europe in the Nordic countries with the foundation of Nord Pool power exchange. It started in Norway as a department in the Norwegian TSO, Statnett, in 1993. In 1996 it became Nord Pool when Sweden joined and the world's first international day-ahead power market was established. Later on, in 1998 Finland joined and in 2000 Denmark joined. The Baltic States joined gradually over the period of 2010 – 2013. The turnover in 2016 for the day-ahead market in the Nordic Baltic area was 391 TWh, which is more than 80% of the electricity consumption in the area.

The Nordic day-ahead market was based on **market splitting**, which de facto is another version of market coupling with only one power exchange involved. The principle is based on the following:

- The TSOs "give" all available transmission capacity (ATC) on the interconnectors between the Nordic bidding zones to Nord Pool. Thus the only possibility to trade between bidding zones is to trade on Nord Pool.
- Nord Pool collects all bids and offers in all bidding zones for the following days 24 hours and calculates the clearing price, traded volumes of all participants and flows on the interconnectors based on an algorithm that optimizes the social welfare.
- In case the calculation shows that it is not physically possible to transport the electricity,

i.e. there is congestion, the markets will split and new calculations will be made.

Other market coupling projects took place in other parts of Europe. Here it was based on the idea of coupling different market areas, with two or more power exchanges involved, into one common market. However, whatever the name, the overall principle is similar. If there is no congestion between two connected bidding zones, the two zones will have the same price. If there is congestion, the electricity will always flow from the high price area to the low price area.

The first example is the trilateral coupling between Belgium, France and the Netherlands in 2006, which developed into the Central West Europe (CWE) market coupling when also Germany and Austria joined the market coupling in 2010.

In 2009, market coupling between the Nordic countries and Germany was introduced with the establishment of a common auction office, EMCC (European Market Coupling Company). This was a cooperation project between the Danish TSO (Energinet), two German TSOs (TenneT and 50 Hertz Transmission), and the power exchange of the Nordic countries (Nord Pool) and the German power exchange (EEX). This coupling was introduced as a simple method, volume coupling, where EMCC calculated the cross-border power flow only based on information on aggregated bid and offer curves in all the bidding zones. Thereafter each power exchange calculated the clearing price in its area and the traded volumes per participant.

This system continued until price coupling was introduced in the full CWE and Nordic area. Hereby the auction office calculates not only the cross-border flow, but also the prices and the traded volumes per participant. In practice, the role as auction office is shifting between the participating power exchanges.

For now, beginning of 2018, market coupling covers most of the western part of the EU and there are plans to cover the remaining part of EU.

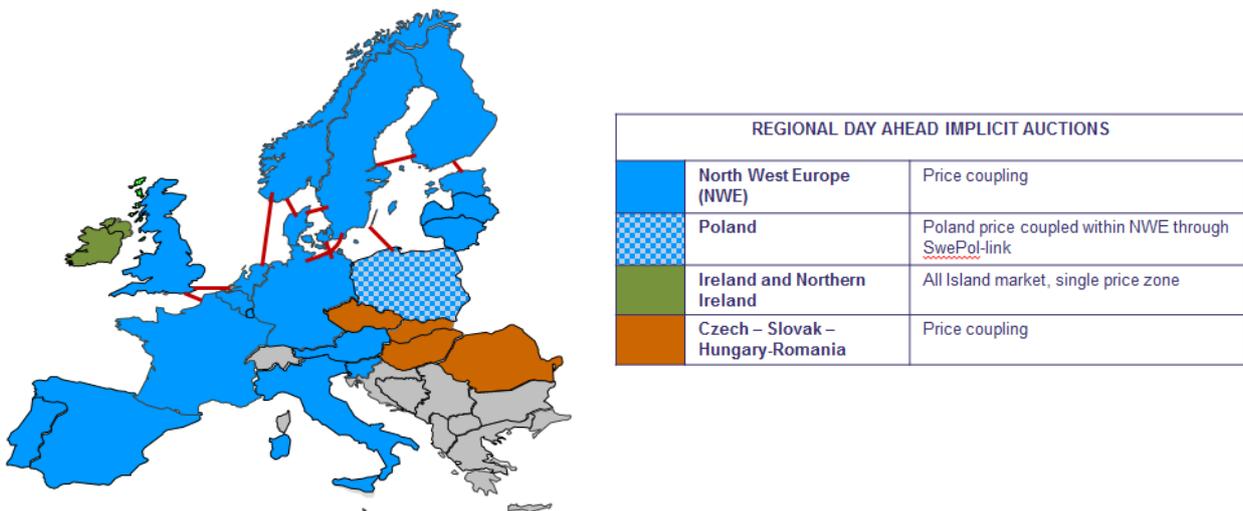


Figure 4. Day-ahead market coupling status in January 2018. Source: APX, updated by Matti Supponen.

The CWE countries have developed the market coupling to become flow-based. In the CWE region, the ATC model was viewed as a step on the way towards the flow-based model. The first CWE flow-based market coupling took place on May 20th 2015. The flow-based method enables grid specificities to be better taken into account, and transmission capacity to be allocated to the market by electrical branch rather than by border, as is the case with ATC-based coupling. This gives a significant socio-economic welfare gain compared to the ATC-

based system. Therefore, flow-based market coupling has become the European target model¹² for meshed grids in Europe. Only in case socio-economic assessments show that there is no welfare gain in shifting to flow-based market coupling, it is allowed to continue with ATC-based market coupling according to European legislation. This could be the case in non-meshed grids, such as in the Nordics. Flow-based market coupling has, however, shown to be challenging to implement, mainly due to problems with developing the advanced IT-systems behind the flow-based system and the development of the system took significant longer time to develop than originally expected.

The European experience is that price coupling (ATC-based or flow-based) is the only viable market coupling which ensures a socio-economic optimal utilisation of the interconnectors.

Volume coupling, as described above, is vulnerable, as flows are calculated on aggregated data only and prices are calculated independently by the individual power exchanges. However, the way price coupling in Europe is organised with power exchanges, which are both obliged to cooperate on a common system and at the same time being competitors, is challenging as it is very difficult for them to cooperate in an open and trustful manner due to confidentiality issues and fears of losing market shares.

3.3.3. INTRADAY COUPLING

In 1999, the intraday market started in Finland and Sweden with the introduction of Elbas. Elbas is based on a continuous trade system, as it is originally thought to be a market place where market participants can make adjustments in order to be in balance, also in case of unexpected incidents. It is operated by Nord Pool and has since then been spread to the other Nordic countries and to Belgium, Netherlands, UK and the Baltic states. Elbas is based on implicit trade, i.e. capacity on the interconnector is an integrated part of the trade.

Figure 5 shows the many different trade systems available before implementation of the single European intraday market platform.

In Germany, EPEX Spot has developed a similar system. However in order to trade across borders, capacity on interconnectors must be explicitly reserved (first come, first served) in separate platforms under the responsibility of the TSOs if a market participant wishes to sell or buy to a customer in a neighbouring country.

Spain started with another approach. In 1998, intraday auctions were introduced, first with two intraday sessions, and gradually incremented the number of sessions to reach six in March 1999. Since then, six sessions of the intraday market have been performed every day.

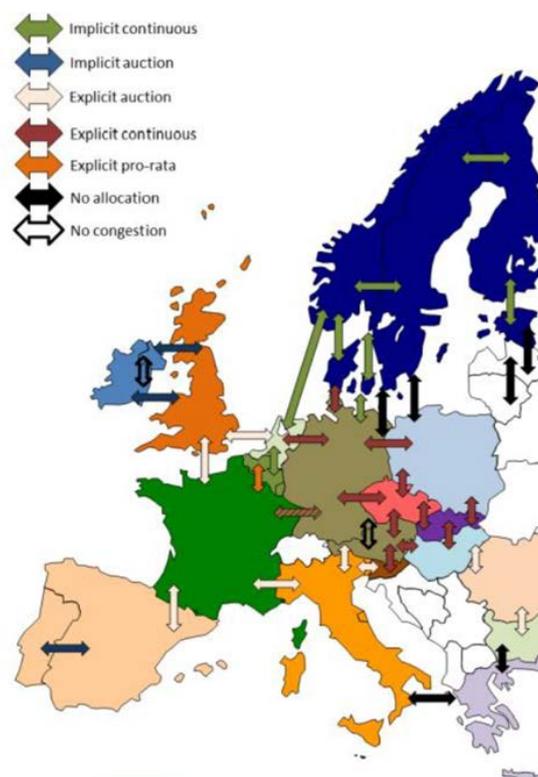


Figure 5. Different trade systems available before implementation of the single European intraday market platform. Source: ACER.

¹² See Guidelines on Capacity Allocation and Congestion management. Link: <http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32015R1222&from=EN>

Many different possibilities of combination of implicit and explicit, continuous and auction models have been developed, making it cumbersome to trade across several borders. Thus there are many reasons to introduce a common European model in order to create a single market for intraday trade of electricity.

The European target model developed to become the continuous trade model, potentially complemented with auctions to create a clear intraday price signal, increase transparency and providing new trading opportunities in an auction format. Latest auctions have been introduced in Germany and it will also be introduced in the Nord Pool area by the end of February 2018. The future European system will be XBID – Cross-border intraday market, which is the implementation of the European target model for intraday. This is a very large project with 4 power exchanges and TSOs from 11 countries. The single intraday market will enable continuous cross-border trading across the entire Europe. This single intraday market solution will be based on a common IT system with one Shared Order Book, a Capacity Management Module and a Shipping Module. This means that orders entered by market participants for continuous matching in one country can be matched by orders similarly submitted by market participants in any other country within the project's reach as long as transmission capacity is available. The intraday solution is based on implicit continuous trading, but can also support explicit trade, where it is requested. The launch date is expected to be June 12th 2018. Eventually XBID is expected to be implemented in all EU member states¹³.

¹³ Extensive information about the XBID system can be found at https://www.epexspot.com/en/market-coupling/xbid_cross_border_intraday_market_project.

4. CHALLENGES WITH MARKET COUPLING

4.1. CHALLENGES WITH MARKET COUPLING

With the European legislation in place it has not been allowed to have specific transit and import/export tariffs on electricity crossing bidding zones and borders. Also distance-related tariffs linked to contracts are not allowed.

TSOs can only set a tariff on the injected electricity (G factor) or on the load (L factor). Such tariffs can consist of both a capacity element (based on kW) and an energy part (based on kWh). The tariff can be sophisticated through locational elements, specific tariffs for system services and grid losses. A detailed overview is being produced on an annual basis by ENTSO-E¹⁴. In the overview, ENTSO-E also calculates the average unit transmission tariff for all Europe. For 2016 this amounts to 8.32 €/MWh for TSO-related costs, i.e. costs related to infrastructure, system services and transmission losses. The overview also shows that most TSOs mainly charge the load and only to a small extent the generation.

To compensate for not being allowed to have transit tariffs or specific tariffs on import and export, European legislation¹⁵ introduced an inter-TSO compensation mechanism (ITC). The ITC mechanism provides compensation for (i) the costs of losses incurred by national transmission systems as a result of hosting cross-border flows of electricity, and (ii) the costs of making infrastructure available to host cross-border flows of electricity.

Congestion income from day-ahead market coupling is also an important income source for the capacity owners of the interconnectors, being the TSOs in most European Member States. The income related to a specific interconnector is typically shared between the owners of the interconnector according to their share of the ownership, often 50-50. The income can according to European legislation only be used for guaranteeing the actual availability of the allocated capacity; and/or maintaining or increasing interconnection capacities through network investments, in particular in new interconnectors. If the revenues cannot be efficiently used for these purposes, they may be used to reduce network tariffs.

4.2. TREATMENT OF LONG-TERM CONTRACTS WHEN LIBERALISING ELECTRICITY MARKETS

A concrete challenge when liberalising and coupling the electricity markets is how to deal with existing long-term contracts that in practice block an interconnector, thus hindering coupling of markets. European legislation foresees now that all interconnector capacity should be available for cross border trade, but there were large challenges in the early days of liberalisation, in particular when the ownership of the interconnector or rights to utilise the capacity were not in the hands of the TSOs.

14 https://www.entsoe.eu/Documents/MC%20documents/ENTSO-E_Transmission%20Tariffs%20Overview_Synthesis2016_UPDATED_Final.pdf#search=tariff

15 <http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2010:250:0005:0011:EN:PDF>

Experience shows that there are different ways to unlock that situation. Some important examples are:

East Denmark & Germany

The “Kontek” interconnector between East Denmark and Germany is owned by two TSOs, but 1/3 of the original investment costs of the interconnector were financed by a generation company, which in return had a reservation of 1/3 of the capacity of the interconnector. With liberalisation, an agreement was made with the company to hand over the reserved capacity to the TSOs for market purposes. As compensation the company received 1/3 of the net income (defined as congestion income from market coupling and revenue from auctioning annual and monthly transmission rights minus operational costs). If the interconnector needs to be repaired, the generation company must also pay their share. The deal was seen as a fair division of income and risks, and due to the fact that the calculation of the compensation represents the market value of the capacity, it is difficult to object. A potential challenge is that in cases of larger operation and maintenance projects these needs to be agreed between all three parties, and there could in some incidents be different assessments of investments, e.g. long-term versus short-term interests.

Norway & West Denmark

The “Skagerrak” interconnectors between Norway and West Denmark. In this case a generation company had the right to transport a certain amount of electricity between Norway and West Denmark. It was agreed to transfer this right to the TSOs for a negotiated sum plus a share of the congestion income for a number of years; a good deal with the large difference in the price levels between West Denmark and Norway. The advantage of this approach is that the generation company is completely out of the decision making process when discussing issues related to maintenance, repair etc. However, it could be difficult to negotiate an outcome.

Sweden & Germany

The “Baltic Cable” between Sweden and Germany. The cable is still owned by the Norwegian generation company, Statkraft, and is thus a clear merchant link. Market wise, the solution has been that the capacity is passed over to market coupling and Statkraft in return receives the congestion income. Thus, from a pure market perspective this may be seen as similar as the abovementioned Kontek solution. However, the cooperation with the Norwegian owner has proven to be very difficult, e.g. with regard to the connection to the German and Swedish domestic grid, participation in the development of common market platforms and cost sharing.

Other European Examples

In other cases of priority reservation of transmission capacity the European regulators stepped in and prohibited reservations (see for instance cases EDF-SEP (Netherlands), RWE (German producer)-SEP, Electrabel (Belgian producer) and EdF (French producer), EdF-ENEL (Italian producer)).

5. TRANSITION TO POWER EXCHANGES

5.1. LONG-TERM CONTRACTS VS. POWER EXCHANGES

Before the liberalisation of the electricity market there often were a direct purchase and long-term agreement between producers and consumers. Municipal-owned distribution companies or large industrial consumers had their own power supplies and national energy companies and system operators were responsible for the overall security of supply. With the liberalisation and the following establishment of power exchanges the agreements were re-negotiated or cancelled.

The power exchanges were seen as important for the market development to create transparency on market prices and following financial products for hedging and risk management of future power prices. The transaction costs for negotiating long-term contracts are relatively high, and with the power exchanges smaller power producers and consumers got the possibility to trade directly on the power exchange with limited costs and the advantage of competition. The long-term advantage for the smaller market participants is dependent on the establishment of, and competition among, new energy risk and asset management companies.

In the electricity market the producer is interested in securing his investment and covering long-term marginal costs and the consumers' interest is to reduce risk of volatile electricity prices and improve his competitiveness by lower electricity prices. Both parties have an interest in hedging their risks in the short term on related contracts. For producers it is i.e. annual fuel contracts and for consumers it could be on the purchase of goods manufactured or the contracts for selling the goods.

Secure efficient balancing, use of infrastructure/assets and low power prices for end consumers

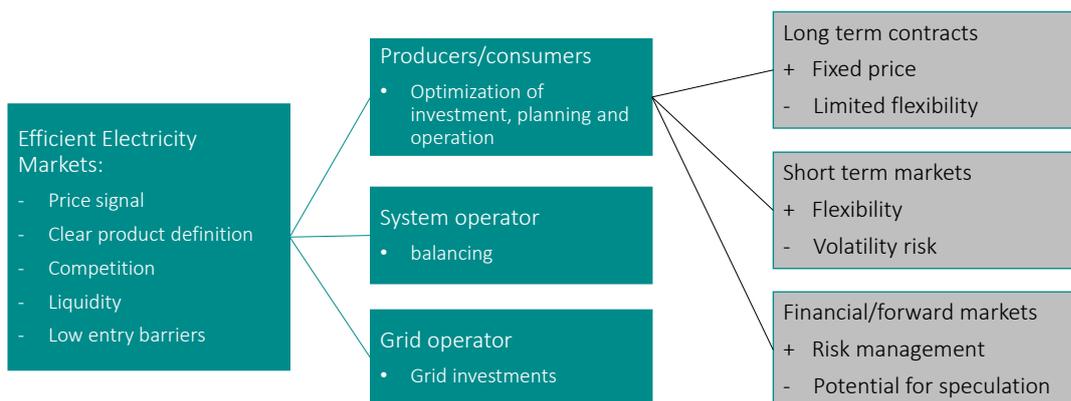


Figure 6. Why electricity markets?

Figure 6 gives an overview of the advantages for the electricity system. An efficient market needs a transparent price signal and with long-term contracts, only the negotiating parties know the prices. There is a need for a clear product definition, i.e. time resolution, minimum/maximum bid volume. There must be competition and it is often discussed how many producers are needed for competition. A general rule is that there should not be a dominating producer able to set the marginal price. Alternatively there is a need for strict competition oversight of the market. Liquidity

is important and related to competition and is dealt with in the next section. Finally, entry barriers such as rules for market participation, financial robustness, and technical competences, should on the one hand be as low as possible to ensure new market actors can enter the market, but on the other hand also strict enough to secure a robust market platform.

The electricity market is also important for the system operator for balancing and the price signal between bidding areas are important for grid investment and utilisation, but this will not be discussed here, where focus is on the relation between market participants and long-term contracts. For the producers and consumers the long-term contracts provide a fixed price and certainty, but they can also have high transaction costs and limit flexibility if the electricity prices increase or decrease. The use of power exchanges gives the flexibility but also a volatility risk that can be difficult to handle, and therefore physical power exchanges are often developed together with financial power exchanges for risk management on i.e. annual financial power products.

The financial market takes advantage of the opposite risk profile of producers and consumers in the power markets. Both producers and consumers want to reduce price volatility risk and the financial power exchanges gives transparency in the willingness to pay for reducing the risks. If the financial market is not properly regulated speculation from financial institutions without assets, speculating in the volatility and changes in price levels can create irrational price development, on the other hand financial institutions can increase liquidity and the efficiency of the financial market.

Physical and financial power exchanges do co-exist and with very different ratios of power consumption in different parts of Europe. Figure 7 below shows the differences in use of the forward markets on the financial power exchanges, over-the-counter (OTC) clearing and non-cleared OTC. OTC clearing refers to bilateral contracts with the use of the exchange for clearing and non-OTC is a direct bilateral contract without clearing. Clearing secures against financial problems of the counterpart and then gives security against bankruptcy or failure of payment. The financial forward markets are 3-6 times higher than the physical volume as they are continuously traded as both expected future demand and production changes together with the expected future price. The differences in use of power exchange forwards, OTC and non-cleared OTC depends on local differences, i.e. transaction costs, national regulation and alternatives for securing forwards. In France for instance, it is still possible for distribution companies to buy electricity at a regulated price.

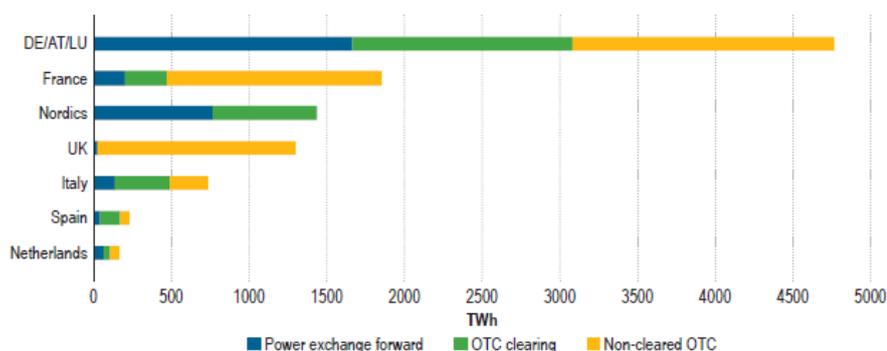


Figure 7. Forward market trading volumes per type in the largest European forward markets 2016 (TWh). Source: European Power Trading 2017 report, Prospex Research Ltd. March 2017.¹⁶

¹⁶ https://acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Market%20Monitoring%20Report%202016%20-%20ELECTRICITY.pdf

The physical power exchange on the one hand facilitates the dispatch of production and on the other hand gives reference power price in a given geographical area/bidding zone. The dispatch can be done in different ways with the Nordic model starting with the day-ahead balancing and the UK model with 30 minutes short-term dispatch trading. Today the power exchanges are a combination of day-ahead, intraday and short term dispatching.

The liberalisation of the electricity market in Europe has over the last 15 years with the development of the market coupling been highly integrated. But the use of long-term contracts still differs. Figure 8 below shows, that in Germany and Nordics the day-ahead and power exchanges for physical trade are used relatively much, whereas the opposite is the case in UK and Central Eastern Europe, where OTC and bilateral trades have high share.

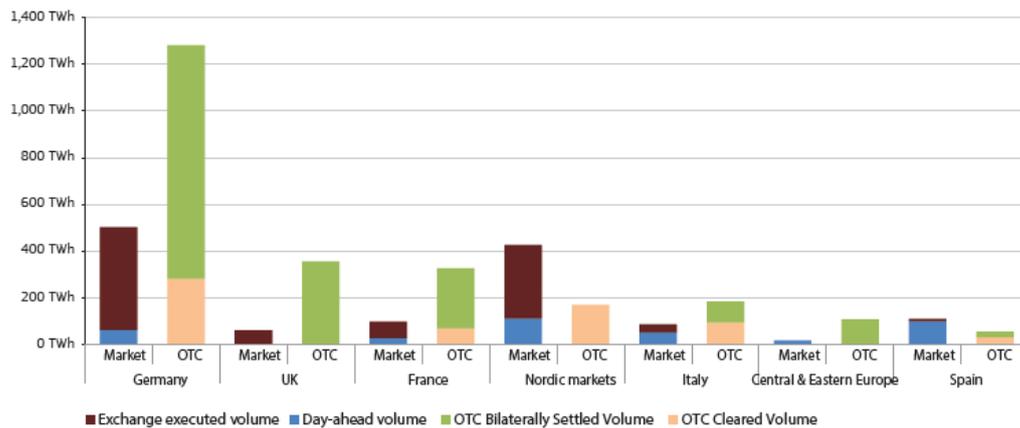


Figure 8. Comparison of Electricity Traded Volumes in Some Important Day-ahead, Forward and OTC Market, first quarter of 2016. Source: Platts, wholesale power markets, Trayport, London Energy Brokers Association (LEBA) and own computations. https://ec.europa.eu/energy/sites/ener/files/documents/quarterly_report_on_european_electricity_markets_q4_2015-q1_2016.pdf

Part of the differences is due to historical regulation and organisation of the power sector. Below a general explanation is given:

Nordic

Hedging on power exchange and use of long-term agreements has overall been low, but use of green PPA are increasing and with use of complex risk management tools to reduce hedging costs.

UK

Producers use power exchanges and power distribution companies have long-term contracts with consumers. Sector is highly vertical integrated.

Central/Western Europe

Mix of long-term agreements and hedging on power exchange and with mix of more large vertical integrated energy companies and many smaller producers and electricity suppliers.

Eastern Europe

Use of power exchange mainly as dispatch and long-term agreements directly between producers and consumers still prevailing. The sector is less liberalised and with alternative regulated power prices.

A further explanation is the electricity system set-up, where need for new capacity can increase demand for long-term contracts to cover long-term marginal costs and secure external financing. Also large increases in demand give incentives to sign long-term contracts for consumers to secure price and delivery. The latest development in the Western and Northern part of Europe are green power purchase agreements (PPA), where subsidies to renewables are market-based and makes it attractive to optimise and reduce market risk. This has created a demand for complex risk management products from energy risk and asset management companies. This development in the electricity market again directly combines specific, mainly renewable energy producers, with consumers with an interest in a green image, and with an energy risk and asset management company as intermediate. This is especially taking place in North Western Europe with new large datacentres being some of the interested new consumers in the green long-term agreements. For example see: <https://www.centrica.com/news/centrica-signs-landmark-balancing-and-hedging-contract-for-wind-farm>

The historical challenge has been the move from the long-term bilateral contracts from before liberalisation to the current situation. This has been a long process with discussions between producers, authorities and consumers. The most successful developments have been where voluntary agreements could be found in a common interest to replace or adapt the contracts, as it was the case in the Nordics and Germany. In other countries the process has been long, and regulated prices to secure investments are still in place. This is the case for instance in France, to cover nuclear power plant investments, and in Britain, where the state owned companies were split by law to create competition.

5.2. INCREASING LIQUIDITY ON POWER EXCHANGES

There are large differences in the liquidity on the European power exchanges and has developed for both the physical and financial trading over time. As the financial trading often replaces the long-term agreements and the physical trading is important for the dispatch and final price signal, liquidity on both products is important. Different actions taken in European countries to increase liquidity are described in the following examples:

TSO selling prioritised renewable energy on power exchange

In Germany the four national TSOs sell the prioritised renewable electricity from small wind and solar producers on the power exchange. This amounts to approximately 20% of total German electricity production.

Remove barriers for electricity risk and asset management companies

Make it easy to trade with the establishment of the new market role as balancing responsible party. For smaller producers and consumers the relative costs can be high but with the establishment of power asset management companies, aggregators or other intermediate companies the costs can be reduced. Further, it is important that the power exchanges have an incentive to develop hedging products that reflect the demand as it may vary with types of production and consumption in a given electricity system.

Market-based subsidies for renewable energy

- In almost all European countries the subsidies for renewable energy and combined heat and power are now adapted to the power market.
- Premium for renewables with a cap or fixed premium gives incentive to get as high a price as possible on the power market.
- Capacity payment independent of production gives incentive to sell and optimise production to market prices. Capacity payment should not give incentive for overinvestments.
- Investment subsidy gives incentive to sell and optimise production to market prices.
- Further, the subsidy can come together with obligation to sell electricity on the power exchange. This can still be combined with a bilateral contract as long as the physical production is sold on the exchange.

Other actions for increasing liquidity

- **Obligatory participation.** In Poland it is obligatory to sell all production on the power exchange. High fees may reduce the advantage of using a power exchange compared to long-term agreements. In order to attract customers with both sales and bid offers, power exchanges could introduce rebate schemes (e.g. charging net positions) thus reducing the incentives to internal trading within vertically integrated companies.
- **Power exchange fee structure.** High fees may reduce the advantage of using a power exchange compared to long-term agreements. In order to attract customers with both sales and bid offers, power exchanges could introduce rebate schemes (e.g. charging net positions) thus reducing the incentives to internal trading within vertically integrated companies.
- **Size of price area.** The larger the price area the more potential volume and liquidity on the electricity market. If the price area is too large it will not reflect the internal congestions and potential benefits from grid investments. The Nordic area is divided in 12 price areas compared to Germany with only one price area and with a larger production and consumption.
- **Transparency.** Publicly available price information and reporting/monitoring makes it easier for market participants to conduct analyses for their own risk management strategies and future planning and investment decisions, based on the electricity price. The European power exchanges all have prices and volumes made publicly available real-time. For operational reasons, prices on the Nordic balancing market are delayed with 1 hour to avoid changes in the production and consumption plans in the operational hour of the market.

