23-06-2015

RE FRIENDLY GRID PLANNING

Danish and European Experiences

DANISH ENERGY AGENCY

ENERGINET.DK

Indhold

1. Executive Summary

This report is an input for China Renewable Energy Centre to be used as part of the 'Boosting Renewable Energy' Program, and the aim is to present international and Danish experiences on planning for integration of large shares of renewable energy.

China has a number of challenges in the area of grid planning and operation in relation to integrate a larger share of renewable energy. The rigidity of the structure and design of China's electricity market runs counter to the kind of flexibility that a power system needs exactly to incorporate higher shares of variable renewables.

The European experience is that a liberalised market has been cost efficient in providing opportunities for integration of renewable energy. A competitive market can be organised in different ways. In Europe the pathway and restructuring of the power sector from monopoly to competition, has been decided politically with the aim of sharperning the competitive edge of industry and integrating the power markets to one single European market. Development of the transmission grid are key to integrate (i.e. couple) otherwise isolated regional markets.

As demonstrated in this report, there is huge wellfare gain for the society by coupling regional markets, and profit from differences in resources and supply structures between regions.

A competive power and auction based ancillary services market is a cost efficient way of securing balancing and reserve capacity and services. Local and regional ancillary service markets in Europe are developing a continuosly stronger integration, and one of the drivers is the increased share of renewable energy in the European power mix. The European Commission and the organisation of Transmission System Operators (ENTSO-E) play a crucial in driving this development.

The important advantages of liberalized power markets in Europe are:

- European-wide competition in generation and trading through market based scheduling of generation and transmission has led to significant gains in efficiency for the sector, as a whole and cheaper electricity prices for the consumers.
- The market provides important price and investment signals for building new generators and new infrastructure at the optimal time and at the optimal place.
- Market prices eliminate the economic losses associated with the old regulatory framework with cost-coverage.

It woudl be possible to introduce market principles for scheduling of China's generators and transmision system along the same lines as in Europe. The establishment of a day-ahead market covering the whole of China, including the main transmission lines between the provinces, is a possibility. Price zones should be established where the borders or zones should be defined according to existing bottlenecks in the transmission system. Price differences between the zones are key for identifying bottlenecks and providing incentives for construction of transmission grid infrastructure.

The report also demonstrates, with examples and real figures from Europe, that the society losses wellfare by building insufficient transmission system that allows the power to flow freely between regions and countries.

It is important that the different resources and supply structures come into of the provinces comes into play. It is a European experience that value will be created by activating the interplay between hydropower, wind power and thermal power in an efficient day-ahead market.

Based on the European experience, a zonal-price approach is recommended, because it is simpler to implement and interpret for the users than the nodal-price approach used in other parts of the world.

The European organsation for Transmssion System Operators (ENTSO-E) approach to developing long term network development plan is an example of a coherent and integrated framework for integration of larger geographical areas and countries into a common well-functioning structure and centralised transmission system platform.

Common evaluation criteria, like the ENTSO-E Cost Benefit Analysis methodology, should be applied in order to ensure coherence and transparancy in the selection of new interconnectors, and those new interconnectors have sound business cases. The investments should be recovered over the transmision tariff.

Power Exchanges play the role of a commercial intermediator in Europe, who is organising the price-settling and the trade. The 10 different exchanges inEurope are organised according different commercial principles, but most supplies a number of products with focus on the day-ahead spot market; and some are offering financial products as well.

2. Introduction

This draft report is prepared by the Danish Energy Agency in cooperation with Energinet.dk. It is an input to the China National Renewable Energy Centre (CNREC) in Beijing and the Boosting Renewable Energy program funded by the Children's Investment Fund Foundation. The aim of the program is to accelerate the deployment of renewable energy in China.

The report is one among other prepared to CNREC as an input to CNREC's reporting to the Chinese National Energy Administration about 'Renewable Energy friendly Grid Planning' and covers European and Danish experiences with grid planning.

The report is closely linked to the report 'Flexibility in the Power System', and the two reports should be in the same context. Therefore you will find lots of references between the two reports on themes like the European power market which is an essential subject for understanding both reports.

The structure of this report is firstly a presentation of our understanding of the current functionality of the Chinese power market, power planning and dispath system for power. It is essential to develop a mutual understanding of the Chinese power system in order to analyse and recommend on future solutions that will enhance China's green transformation. It is therefore our hope that our Chinese partner will comment and deepen our understanding of the current system and the challenges.

Chapter 3 of the report describes the European power markets their functionality of a liberalised power system.

Chapter 4 describes the Trans-European framework for planning and operation of transmission infrastructure, including the framework for planning of new interconnectors.

Chapter 5 is about the management of the Danish transmission infrastructure.

Finally Chapter 6 describes the role of the Power Exchanges and organisation in Europe.

3. Introduction to the challenges for the Chinese planning, forecasting, scheduling of generation and transmission

3.1 Power Sector Set-up

In terms of power generation China has abundant energy reserves. The country has the world's third-largest coal reserves and massive hydro-electric resources. But there is a geographical mismatch between the location of the waste coal reserves in the north-east (Heilongjiang, Jilin, and Liaoning provinces) and north (Shanxi, Shaanxi, and Henan provinces), hydropower in the south-west (Sichuan, Yunnan, and Tibet provinces), and the fast-growing industrial load centres of the east (Shanghai-Zhejiang province) and south (Guangdong and Fujian provinces). This is also the case to some extend for variable renewable energy sources like wind and solar.

The current set-up – Unbundling the Chinese power industry
After 2002 the energy industry in China is undergoing a process of separating enterprise from the government, the goal of which is to establish a healthy energy sector. In 2002, based on the principle of separation of electricity production and transmission, China reorganized the State Power Corporation, set up independent electricity producers, and ended the government’s vertical-control framework in which the electricity production, transmission, distribution, and selling were tied together.

All operations under the State Power Corporation were divided into two types of businesses: electricity production; and electricity grid. Five independent electricity producing enterprises were set up, and they each had more than 30 GW of installed capacity. They are:

- China Datang Corporation
- China Huadian Corporation
- China Guodian Corporation
- China Power Investment Corporation
- China Huaneng Group.

These five companies occupied six regional electricity markets, and provided the solid foundation for a competitive electricity market in each of those regions.

The power grid connection is still an oligopoly. Two power grid companies were setup: the State Grid Corporation (SGC); and China Southern Power Grid (CSPG). The SGC was a state-owned corporation, which setup five regional power grid companies. The CSPG was rebuilt by the Guangdong Provincial Government, Hainan Provincial Government and the SGC on the base of the existing power grid connection. In addition to the two major grid operators the western part of the Inner Mongolia grid is managed by the independent grid company Western Inner Mongolia Grid Corporation (WIMGC).

Generally speaking, China's electricity industry has mostly been focusing on separating electricity production from transmission and distribution, and has made significant progress in investment system reform, opening up the electricity production process, and separating electricity enterprises from the government. However, its structural reform is still incomplete. From the market entrance perspective, private and foreign investments still have some disadvantages compared to state-owned companies, and a diverse ownership structure has not yet been established. The power grid companies still own a number of power plants; thus, the separation of electricity production from the grid-connection is incomplete.

Some major electricity consumers, such as large steel factories, still have their electricity allocated to them by the government, instead of being able to bid for a better price in the market. Introducing competition in to the generation sector is still experimental. The power grid companies are the only buyers of electricity from the producers, and the only sellers of electricity to the consumers; thus, they have a monopoly. In a nutshell, China's electricity industry is still far from being a fully competitive market with diverse market players.

3.2 Forecasting, scheduling and dispatching

The rules and regulations currently governing electricity dispatch in China are stipulated in a 1993 State Council regulatory directive, Grid Dispatch Regulations, which was revised in 2011. This document allocates authority and responsibility for dispatch, sets an organizational hierarchy, and specifies a basic process for and rules governing dispatch.

Implementation instructions for the Regulations were provided in the then-Ministry of Electric Power's Implementation Measures for Grid Dispatch Regulations, which was released in 1994. The Regulations were motivated by the need for more formal dispatch organizations and rules following the pluralization of generation ownership that occurred over the 1980's, in particular as local governments began to finance and build generation within their jurisdictions.

Under the current regulations the National Energy Administration (NEA), have the authority to determine the responsibilities of dispatch organizations (DO's), their geographic scope, and their jurisdiction, or which DO's have control over which generators and transmission facilities. DO's are currently Power Dispatch and Communications Centres within the State Grid Corporation of China (SGCC) and provincial and regional grid companies, and variously named dispatch centres within prefecture- and county-level electricity supply companies.

The organizational hierarchy laid out in the regulations is based on a principle of "unified dispatch and multi-level management". This principle sought a political compromise between the need for unified dispatch, following a diversification of generation ownership, and the task of local governments to manage local generation and loads. Multilevel management is based on a five-level hierarchy of DO's, each with a separate jurisdiction and function. 1 below provides an overview of this hierarchy, showing the division of responsibilities for three key functions: supply-demand balancing (balancing), generator dispatch (dispatch), and load management. Although the DO's in Table 1below are functionally separate, with the exception of the China Southern Grid region, the regional and provincial grid companies to which regional and provincial dispatch organizations belong are subsidiaries of SGCC.

Level	Host	Jurisdiction	Key Functions
National (NDO) 国调 | guodiao	SGCC	*Voltage level*: >500 kV *Geographic*: Regional interties *Generators*: Large thermal or hydropower shipping across regions	Interregional balancing, interregional dispatch
Regional (RDO) 网调 | wangdiao or 总调 | zongdiao	Regional grid companies	*Voltage level*: 330–500 kV *Geographic*: Provincial interties *Generators*: Pumped hydro storage, regulation	Interprovincial balancing, interprovincial dispatch
Provincial (PDO) 省调 |shengdiao or 中调 | zhongdiao	Provincial grid companies	*Voltage level*: 220 kV (330–500 kV terminal substations) *Geographic*: Bulk provincial system *Generators*: Larger generators not controlled by RDO or NDO	Intra-provincial balancing, intra-provincial dispatch, coordinating load management
Prefecture (MDO) 地调 |didiao or 市调 | shidiao	Prefecture power supply organizations	*Voltage level*: ≤220 kV *Geographic*: Local system *Generators*: Smaller local generators	Prefecture load management
County (CDO) 县调 | xiandiao	County power supply organizations	*Voltage level*: ≤110 kV *Geographic*: County system *Generators*: Any remaining generators	County load management

Table 1 *Overview of Dispatch Organization Hierarchy,* Source: *IEEE Power & Energy Magazine*

DO's that are lower in this hierarchy (e.g., county-level) are required to comply with instructions from those more senior in the hierarchy (e.g., provincial-level).

Unified dispatch is achieved through rules and procedures that institutionalize coordinated planning and real-time management among these organizations, described below.

The three principal actors within this five-level hierarchy are SGCC (the NDO), the RDO's, and provincial dispatch organizations (PDO's), which are responsible for scheduling and balancing most of the system. The division of labour among SGCC, RDO's, and PDO's is somewhat subtle, and easier to see from their interaction in the scheduling and dispatch process. As a general principle, scheduling and balancing responsibilities among DO's are separated according to geography and voltage levels, with PDO's responsible for managing the 220 kV provincial grids and generators that are dispatched to meet within-province demand, and RDO's responsible for higher voltage (330–500 kV) provincial interconnections and generators that are dispatched across provinces. The NDO, SGCC's dispatch centre, has jurisdiction over regional grid interconnections and generators that are dispatched across regions.

Prefecture-level dispatch organizations (MDO's) and county-level dispatch organizations (CDO's) are responsible for implementing dispatch instructions from PDO's, monitoring frequency and voltage conditions in local grids, and managing local generators and load. MDO's control any generating units in their geographic area that are not under the control of a more senior DO, as well as lower voltage (<110 kV) sub-transmission and distribution substations and lines in their jurisdiction. CDO's typically control any remaining generating units that are in their jurisdiction, as well as substations less than 110 kV and distribution lines less than 35 kV. MDO's and CDO's are responsible for demand planning within their jurisdictions, a process that is coordinated across the province by the PDO's.

Each level in the five-level hierarchy of dispatch organizations develops detailed dispatch rules and procedures, which are contained in Operating Procedures for Dispatch. Topics covered in these Procedures include management responsibilities, procedures for frequency and voltage control and contingency management, and rules for equipment repair schedules and information exchange between dispatch organizations.

China's five-level dispatch hierarchy evolved organically over time. Its administrative complexity stands in contrast to the shift toward centralized system operators and wider balancing areas seen internationally, reflecting economies of scale.

Annual Demand Planning

To allocate available supply (generation capacity), provincial planning departments develop annual plans that give each municipality and county an "electricity use quota", typically by quarter. These quotas are for a maximum not-to-beexceeded peak load, including line losses. They are developed on the basis of expected available generation capacity (including net exports), economic metrics, and historical demand, although methods for allocation appear to vary by province and are not made public. Prefectures and counties are not permitted to exceed their quota, and can be penalized if they do. Prefecture and county planning departments allocate these quotas internally among regions within their jurisdictions on the basis of an Orderly Electricity Use Plan, as required by the NDRC's Measures, with allocation also done using a combination of economic metrics and historical demand. The process of allocation, both among municipalities and counties and individual customers, is an important lever for implementing national and local industrial and environmental policy, although it also appears to be open to political influence.

As a final step in the demand planning process, RDO's and PDO's develop seasonal load management plans on the basis of provincial and local load allocation plans and local plans for peak load shifting, avoidance, rationing, and curtailment. Most of the actual planning is carried out by PDO's, with RDO's responsible for aggregation and coordination. RDOs' and PDOs' seasonal management plans focus on peak balancing and forced outage preparedness, and strategies for managing load in peak demand months.

Annual Generator Output Planning

Provincial planning agencies, typically provincial Economy and Information Commissions, are responsible for planning annual generator output. For provinces that do not use energy efficient dispatch system (a pilot system introduced in 2007 in Guangdong, Guizhou, Henan, Jiangsu, and Sichuan Provinces that specifies a dispatch order, with renewable, large hydropower, nuclear, and cogeneration units given priority over conventional thermal units, and conventional thermal units within each category), each year provincial agencies develop an annual generator output plan, which is based on a recommended plan drafted by the PDO and approved by the provincial grid company. The plan is typically drawn up in October and finalized and distributed in December. Annual and monthly output totals from this plan are included in annual contracts for generators.

Annual output plans are intended to guarantee operating hours for generators, subject to system constraints, and are not intended to be "guiding" targets. Approaches to determining operating hours for different generator technologies and power plants vary among provinces.

Under current law, grid companies are required to give renewable energy priority in dispatch and, by extension, in output planning. Priority dispatch in China takes two forms. Firstly, SERC's 2007 Regulatory Measures for Grid Companies' *Full Purchase of Renewable Energy* requires grid companies to purchase all renewable energy, regardless of dispatch system, subject to grid security constraints. Secondly, in provinces that use energy efficient dispatch, non-fossil fuel resources are prioritized in dispatch order, similar to priority dispatch policies found in Europe. Purchase requirements have not been successful, as the high level of wind curtailment indicates. The effect of priority dispatch under the energy efficient dispatch system is not yet clear, as it has largely been implemented in provinces that do not have high penetrations of wind or solar energy. As an alternative, the NEA has proposed a national system of provincial quotas for renewable energy, imposed on provincial grid companies.

Generator output planning, and its link to investment cost recovery for thermal generators, creates a conflict between renewable and thermal generators. For wind and solar energy, output is inherently variable and growth in output may exceed growth in demand, reducing output for other generators. As long as fixed cost recovery for thermal generators, and the idea of 'fairness' in adjusting their annual contracts, is tied to output, this conflict is not easily reconcilable.

3.3 Planning of transmission lines

China does not have a unified national electricity grid. Its current grid system is fragmented into six regional power grid clusters, all of which operate rather independently. The State Grid Corporation of China (SGCC) manages four of the clusters (the East, Central, Northwest, Northeast grids) as well as part of the North grid (specifically the eastern part of the Inner Mongolia grid). This network covers 26 provinces. The western part of the Inner Mongolia grid is managed by the independent company Western Inner Mongolia Grid Corporation (WIMGC). The South grid is managed by the China Southern Grid Company (CSGC).

Figure 1: *Regional power grid clusters in China.* Source: Market potential and technology transfer, NDRC Energy Research Institute, November 2009

Non-variable power generation from thermal will most likely still dominate China's energy mix in the medium and long run, and hydro is the single largest contributor of non-fossil fuel power generation. But large-scale coalmines and hydro stations are located equally far from demand centres in the east. Inner Mongolia, for example, holds one of the largest coal reserves in China. New high voltage transmission lines could help alleviate the logistical bottleneck of coal transportation and secure electricity supply.

Another issue in the Chinese power transmission system has been power loses in the long high voltage transmission lines in China. In order to reduce these loses China has been focusing on ultra-high voltage lines (UHV) of 800 and 1,000kV instead of the traditional 500 kV transmission lines that most of the current transmission system is based upon. This technical solution should reduce power loses by more than 90%. Currently China has eight of these UHV lines with one additional coming online this year.

At the receiving end, to cope with the large quantity of electricity transmitted to the east, enhanced interconnections of regional grids are needed to handle the influx. To avoid congestion and potential damage to individual grids in case of major power fluctuations, SGCC is planning to significantly strengthen the interconnection of its three regional grids in the east, central and south of the country.

Based upon the current structure of the Chinese power grid including the players involved (power generators and grid operator) the business cases for the new transmission lines focusing on the system balancing issues of large quantities of variable energy sources like wind and solar is not that obvious for the individual players. Long-term contracts and the lack of power exchanges that benefits from the low marginal costs of wind and solar generated electricity also reduces the underlying business case for such a grid expansion. This problem is not only related to China but shared with specific areas in Europe like the border between France and neighbouring countries Spain and Italy. Low power prices in France based upon the mature fleet of nuclear power stations makes it less obvious that France should expand its grid capacity with Spain and Italy that has relative high power prices.

3.3 Challenges in relation to flexibility and integration of renewable energy

Grid codes and practices were designed to support power systems dominated by heavy industrial demand and base load coal generation for an economy in which output was, to some extent, planned. Many of these practices will need to change to accommodate the increasingly diverse needs of a dynamic economy and the government's vision of a low-carbon electricity supply powered by significant amounts of variable wind and solar generation.

The challenges of integrating wind and solar generation into power systems in China are becoming increasingly clear. In 2014, an estimated 8% (162 TWh) of potential wind generation was curtailed in all of China and 12.5% in the top 6 wind energy provinces. With very limited marginal costs for wind generated electricity the current curtailment represent a huge economic loss for China compared to running fossil fuel based generation with much higher marginal cost due to fuel expenses. Such high levels of curtailment, at relatively low levels of wind penetration, are not consistent with experience in other countries. They are clearly unsustainable if wind and solar energy are to be a major part of China's generation mix going forward.

Local governments still administratively ration electricity demand and plan output annually for power plants; generating units are then scheduled and dispatched according to plan rather than through least- cost optimization. Dispatch is managed through a multilevel geographic hierarchy that mirrors a political hierarchy, in which power plants that were built to export power across regions and provinces have their output planned by the central government and receive priority in the importing province's dispatch. These institutions now appear excessively rigid relative to the diverse needs of the Chinese economy and a low-carbon electricity supply with high penetrations of wind and solar energy.

Integrating high penetrations of variable renewable generation at a reasonable cost requires loads or other generation resources that are able to respond on intraday timescales to changes in renewable output. Greater intraday flexibility in loads and resources in turn requires more flexible and efficient planning, scheduling, and dispatch processes.

In China, current approaches to managing dispatch, planning generator output, rationing demand, and scheduling and dispatching generators were designed for a previous era in which neither loads nor generation resources were particularly variable, and are not consistent with the needs of power systems that have high penetrations of variable generation. More specifically, five features of current practices create challenges for integrating renewable generation:

1. Output planning for thermal generators: In provinces that do not use energy efficient dispatch, annual generation output planning requires dispatch organizations to maintain operating hours for coal units even when use of existing, low-variable-cost hydropower, wind, and solar generation would reduce system costs. This creates an obvious conflict of incentives with renewable energy goals.

2. Administrative demand planning and rationing: The current approach to load management was designed to administratively restrain demand levels below a fixed quantity of supply, and not to respond to changes in supply over the course of a day, as would be required to use demand response as a resource for balancing variable generation.

3. Fixed schedules for interregional and interprovincial power exchange: Allowing SGCC and the RDO's to fix schedules for interregional and interprovincial generation in advance of PDO schedules overly constrains dispatch, potentially leading to wind curtailment when out-of-province generators can be more cost-effectively backed down.

4. Lack of optimized, economic dispatch: In all provinces, DO's currently do not optimize dispatch across generating types (e.g., across coal, gas, and hydropower units), which means that some units might be running out of merit and are not maximizing their value to the system. This lack of system-wide, marginal-cost-based dispatch means that there is little basis for economically rationalizing curtailment of variable renewable generation. Moreover, provinces that do not use energy efficient dispatch have an ad hoc approach to dispatch, providing policy-makers with little visibility on optimal electricity sector policies and planners with little visibility on optimal choices for new generation.

5. Lack of system visibility: The multilevel approach to dispatch management means that no one DO has visibility over all generators and transmission facilities within an entire control area, which slows response during emergency conditions.

3.4 Power market reform under way, pilot projects

There is clearly a strong focus among the central government in China for the challenges that the power industry is currently facing including the problems of fully utilize the renewable energy sources of the country and current and future renewable energy assets including wind farms and PV installations. It seems that there is more political attention on the fact that China is currently wasting “free energy” by curtailing renewable energy production that carries very low marginal costs.

Stated in a memo issued by the Central Committee of the Communist Party and the State Council of China in March 2015 (Document No. 9) the focus of Deepening Power Sector Reform is made clear based upon some of the challenges of the Chinese power industry including power market liberalization, accommodating grid codes vs. variable energy sources like wind and solar. The memo is highlighting five basic principle for the next phase of power market reforms:

- Power supply safety and reliability
- Power industry market oriented reforms
- Power supply that ensure the Chinese people’s livelihood
- Power market that supports energy savings and emission reductions
- Further scientific supervision in developing the Chinese power sector

Apart from current pilots and explorations have been carried out for on-grid competitive prices, director power trading between large users and power enterprises, power generation rights trading, inter-provincial power energy trading and other aspects and dispatch procedures like efficient dispatch system the memo includes new initiatives to develop actively launch various pilot and demonstration projects of distributed power generation like solar (PV panels). On top of the memo suggested that power market pilots can be firstly launched for power seller side reform, the establishment of relatively independent power trading organizations and significant reform issues, which can be comprehensively launched on the basis of summarization of previous pilot experience and amendment and improvement of relevant laws and regulations later on.

Although highlights the importance and urgency of the reform of Chinese power system there is an overall emphasis on a maintaining stability and make changes in an orderly manner. Also the embedded conflicts between different stakeholders both in different part of the value chain and between regional and provincial stakeholders is not addressed specifically although there is reference to possible actions by national entities like NDRC and NEA.

As further reforms still are in the making it is difficult to judge possible actions and results at this point of time for the ability of China to gain the full environmental and economic impact of both current and future renewable energy assets.

3.5 Conclusions

A quick summation of some of the inherent characteristics of China's electricity market shows the need for more radical solutions to support greater penetration of variable renewables:

- Diminishing numbers of smaller plants mean that system operators will rely more on big coal plants for flexibility and balancing.

- Independent management of three grid companies creates low incentive for these companies to solve transmission cross-border bottlenecks.

- Fixed on-grid and end-use electricity prices mean there is no spot market and hence little incentive for utilities to release spare capacity or to maintain ancillary service units.

- Long-term contracts for electricity trading among regions and provinces mean that both tradable amount and prices are fixed a year ahead; there is no price incentive for system operators to accommodate imports including low-marginal cost renewable energy sources like wind and solar.

In China, the current approach to coordinating dispatch across BA's is primarily through the system of multilevel management, in which SGCC and the RDO's schedule and dispatch planned output from dispatchable generators across provinces. Market-based cross-border exchange, which in principle provides flexibility to PDO's, is currently designed for addressing imbalances on day-ahead or longer timescales.

The rigidity of the structure and design of China's electricity market runs counter to the kind of flexibility that a power system needs exactly to incorporate higher shares of variable renewables. The central government's tight grip on pricing is a key challenge that could undermine its own efforts to enlarge the country's transmission and flexible generation capacity. Measures undertaken are usually heavily administrative: change is driven by target-setting rather than market forces. Yet clear targets set by the Chinese government give the market and industry long-term confidence and certainty that renewables will continue to grow, and that all solutions that contribute to the integration of renewables are on the table.

4. The European power markets

4.1.1 The liberalisation of energy markets in Europe

The first EU liberalisation initiatives on electricity and gas were adopted in 1996 and lead to a start of market opening and separation of the monopoly tasks (transmission) from the commercial tasks that comprise production and trade.

Since then the European Commission (EC) has been the driving force behind the liberalisation of the European electricity and gas sector. The latest large initiative was the so-called third liberalisation package from 2009. With this package a clearer unbundling between transmission system operators (TSO's) on one side and production/generation and trading on the other side was formed thereby securing TSOs' full independence of commercial interests is secured.

In addition, the third package should make electricity and gas flow more easily across borders. The intention was to streamline regulations in the member countries. To accomplish this target, a tighter cooperation between national regulatory authorities (NRA's) was established, and the ACER (Agency for the Cooperation of Energy Regulators) was formed. With the third package also ENTSO-E and ENTSOG (European network of transmission system operators for electricity and gas, respectively) were formed as cooperating bodies for TSO's in order to coordinate grid planning and operations

In 2009 was energy included as an item for EU-cooperation, i.e. part of the internal market. The EU now have a basis for working with broad energy agendas and develop a commun Energy policy an Energy Union.

4.1.2 Guiding principles

TBC

4.1.3 The liberalisation process of theEuropean power markets

TCB

4.1.4 Evolutions in European energy markets since 1990

TBC

4.1.5 Transitional issues

TBC

4.2 Forecasting and scheduling of generation and transmission

Before the market opening in Europe, merit order dispatch was typically done by the central dispatcher in the vertical integrated company (monopoly), see Figure 2. The amount of capacity needed in order to serve the expected load was put into operation following a least cost merit order ranking.

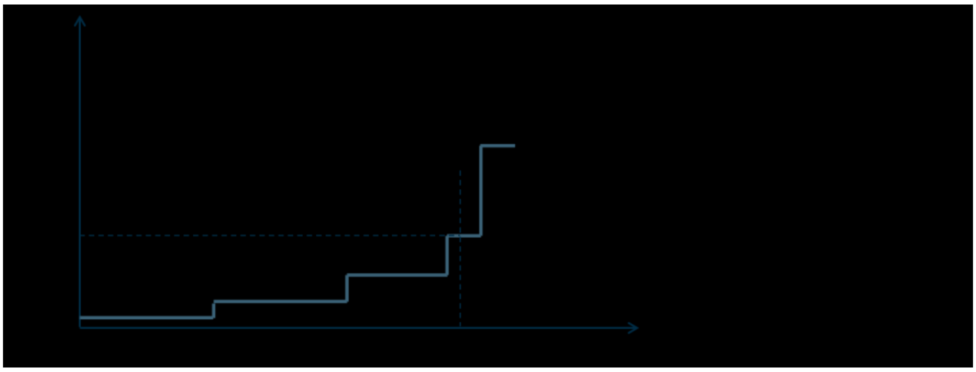


Figure 2: Before market opening, merit order dispatch was done by the central dispatcher

This approach was possible due to simple cost structure and cost information being centrally available at the monopoly. However, the power systems are no longer simple.

Figure 3 shows the development of the power system in Denmark from about 1990 until now. Besides, it shows the time for market opening in Denmark (and in the Nordic countries) being around year 2000. The vertical integrated power monopolies were broken down into commercial companies for generation and trade and new monopolies for transmission and distribution.

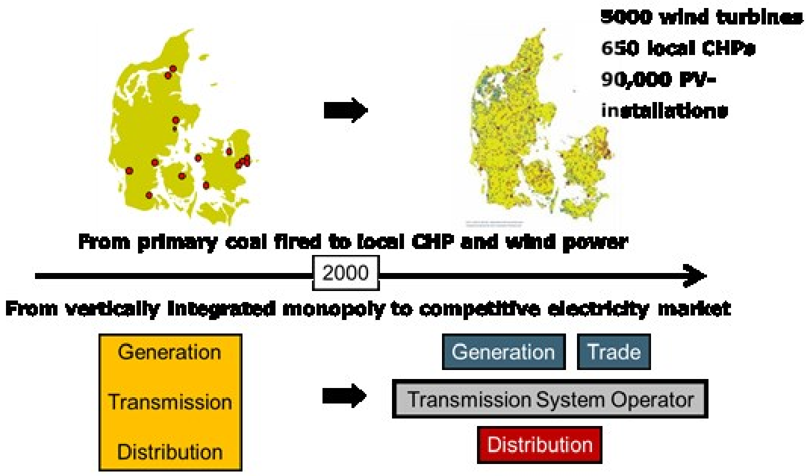


Figure 3: Towards renewable energy and open markets (Denmark)

4.2.1 Day-ahead European market

Generation and transmission scheduling in Europe is primarily taking place in the price coupled integrated European day-ahead market. Figure 4 gives an overview of actions and processes in the different markets: day-ahead, intraday and regulating power market, and how they are interlinked with the reserve markets (capacity reserve for regulating power market and primary reserve market) and form basis for the TSO's daily operation and control.

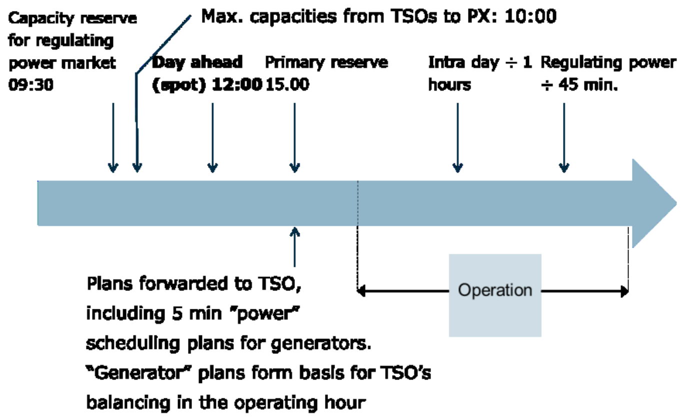


Figure 4: Overview of market actions/processes

Each day before 12 o'clock AM the market actors in the whole of Europe give in their bids to the market operator (European power exchanges, see later in this section) for generation and demand, see principle illustrated in Figure 5. Assuming well-functioning competition, market actors submit bids reflecting marginal costs. The supply and demand bids are summed up and a price cross defining electricity amount and wholesale price is defined.

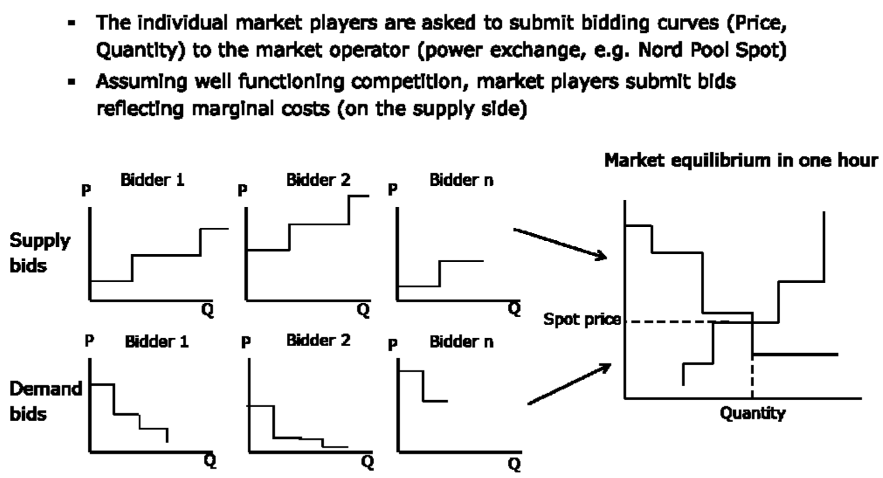


Figure 5 Principle of day-ahead price formation

For explaining in principle how transmission is implicitly scheduled reference is made to Figure 6 showing two bidding areas connected by a transmission line with capacity “E”. The optimal scheduling is to transport the amount “E” from the low price area to the high price area. Thereby the price will increase in the low price area and decrease in the high price area as shown in the figure. The prices in the two zones will in this case end up being different due to congestion constraint on the interconnector.

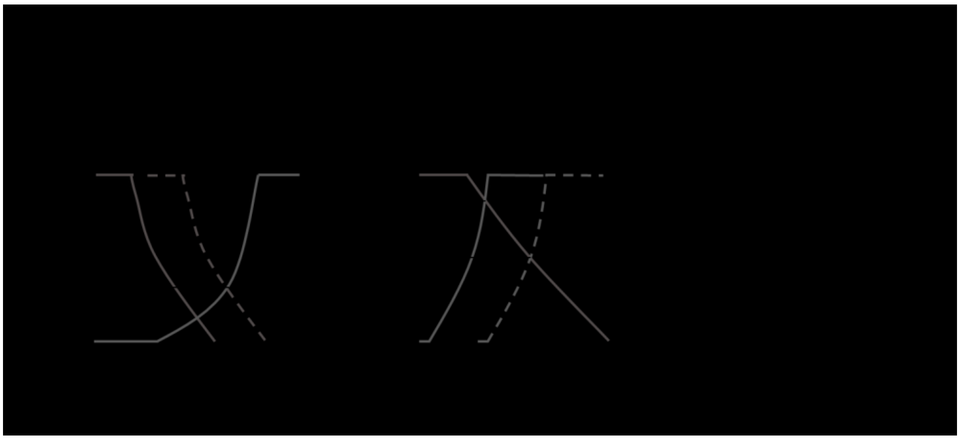


Figure 6: Principle of joint scheduling of generation and transmission for two inter-connected bidding areas

If the interconnector capacity is sufficient, the day-ahead spot prices in the two zones will converge towards equal prices, see Figure 7. It should be notified, that even if the capacity of the interconnector is larger than “E”, the optimal schedule for the line is still “E”.

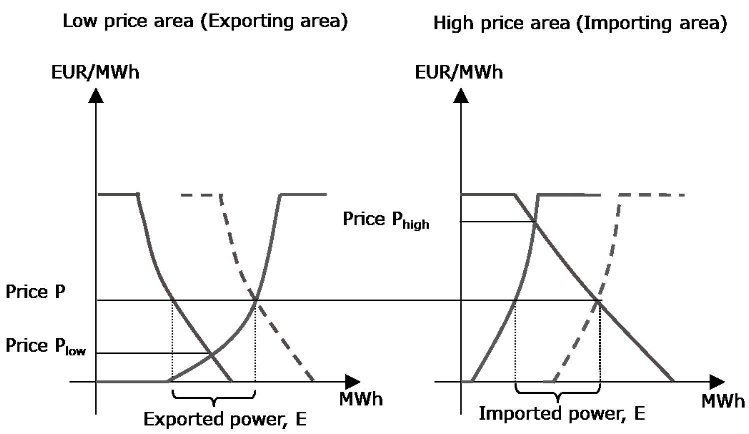


Figure 7: Two price areas/zones with transmission link capacity greater than or equal “E”

The day-ahead market in Europe has evolved over time. This is illustrated in Figure 8. The market started with price coupling in the Nordic region and has developed since. By February 2015 the “blue-coloured” area in the figure is operated as one big price-coupled are: from Northern Scandinavia to Sicilian in south. It is noticed that four countries in Eastern Europe (read colour) are not yet coupled to the MRC (Multi area Price Coupling). Each country is divided in price areas or zones. Between zones there are transmission lines with transmission capacities, which may be updated by the TSOs each day before 10 o’clock, see Figure 4.

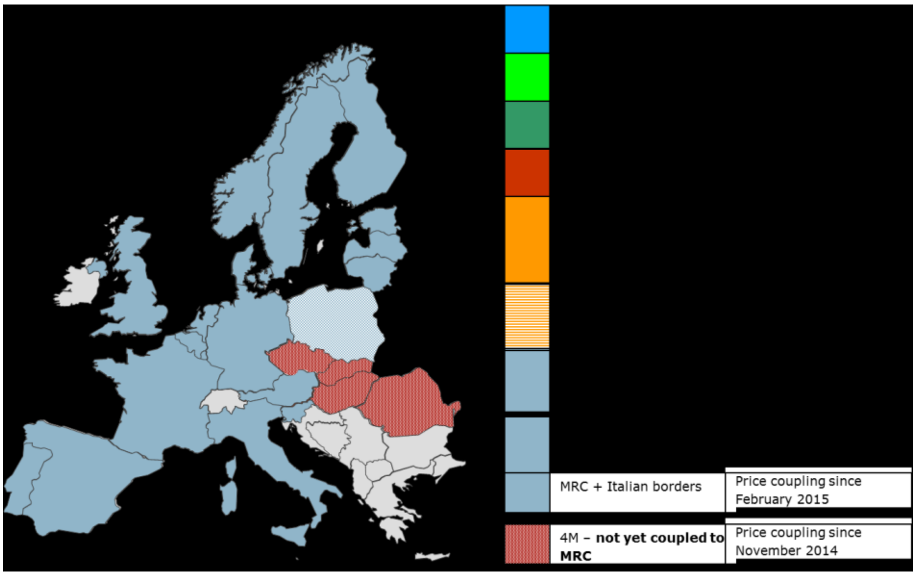


Figure 8: Blue area indicates extension of multi area price coupling market by February 2015

The market coupling works as illustrated in Figure 9: Market coupling, EuropeFigure 9. The PXs (Power Exchanges) in Europe work together. Each regional PX gives in the received bids to a common platform, where one common algorithm solves the joint market scheduling of generation and transmission for Europe. The results of the calculations are prices for each hour of the following day and hourly schedules for generators, demand and interconnectors. The results are forwarded to the individual market participants and the TSO’s.

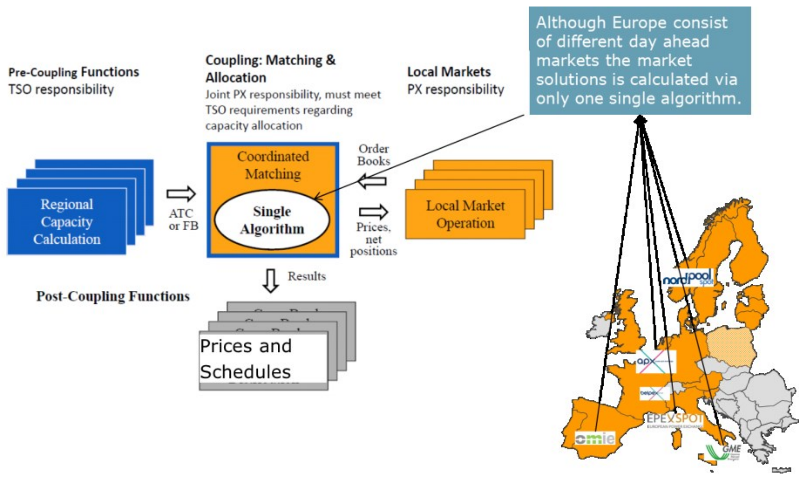


Figure 9: Market coupling, Europe

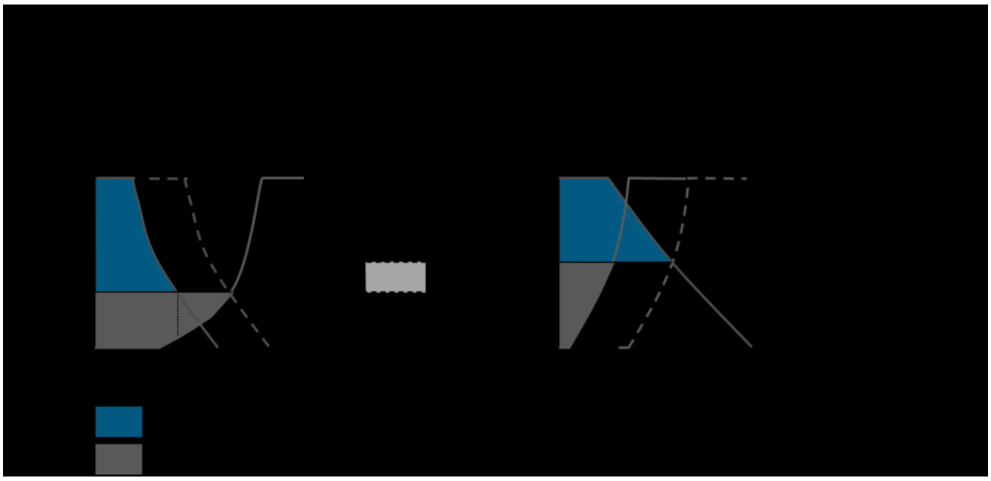


Figure 10: Definition of principles of the optimisation algorithm for calculating the economic optimal market solutions in the day-ahead market taking transmission constraints into account

The algorithm finds an equilibrium solution for quantity of production/demand and price for each hour through the following day. The solution maximises the sum of social welfare in the entire market, taking the capacity constraints into account. Social welfare is the sum of consumers' and producers' surplus and the congestion revenues on all transmission lines. The principles of this calculation are illustrated in *Figure* 10 for a simplified price coupling of two areas/zones.

The overall objective is to use the interconnectors to meet demand with the cheapest possible production costs (lowest possible marginal costs). In this way the function of the interconnectors is to reduce production cost to the widest extend possible. As a natural consequence production will flow from areas with large RE production (with approximately zero marginal costs) to areas with thermal production based on fossil fuel (higher marginal cost). In a similar fashion areas with high demand compared to production capacity (like many areas in eastern China) will usual have an inflow of production as prices will tend to be higher in those areas. This is further elaborated in Chapter 5.

Congestion Management

As described above the transmission scheduling is determined in a joint process with the generation scheduling. This is also called congestion management by implicit auctions of transmission capacity.

In the evolution process in Europe, with regional but not price-coupled markets, explicit auctions were used for congestion management. In this concept the trade of interconnector capacity takes place before the day-ahead prices are calculated; the right to use the interconnector capacity is auctioned independently from the energy trade. *Figure* 11 illustrates the principle of this concept.

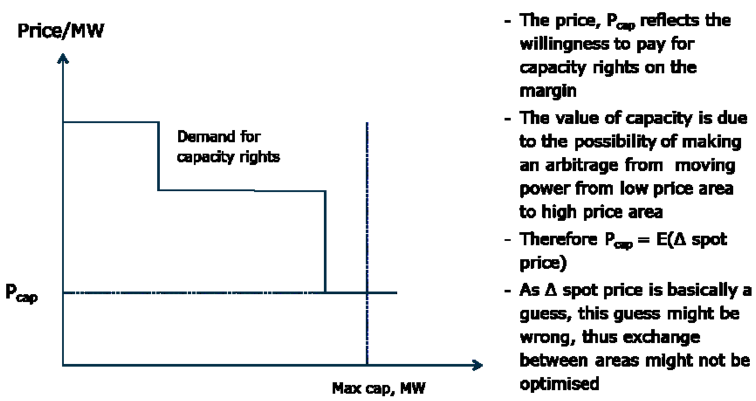


Figure 11: Example of explicit transmission auction

As explained in *Figure* 11, an explicit auction may not be a fully optimal solution, as the market trader of capacity does not know in advance the prices in the two areas, where he buys trading capacity. *Figure* 13 illustrates the problem.
It shows the flow over the border between Denmark (DK West) and Germany in 2006 before price coupling between the two markets. It shows exchange of energy in the “wrong” direction in 25% of the year (14%+11%), meaning that power flows from higher market price towards lower price. These situations represent a welfare loss. The third concept of congestion management is counter trade or re-dispatching. In contrast to implicit auctions and explicit auctions, congestions are not managed day-ahead but through counter trade of generation after gate clo-

sure in the day a-head market, typically in the real time regulating power market. This type of congestion management is needed to apply, when congestions occur inside the price zones and not solely at the borders to other zones. When counter trade becomes a structural and permanent issue, a review of the bidding zones layout should be considered.

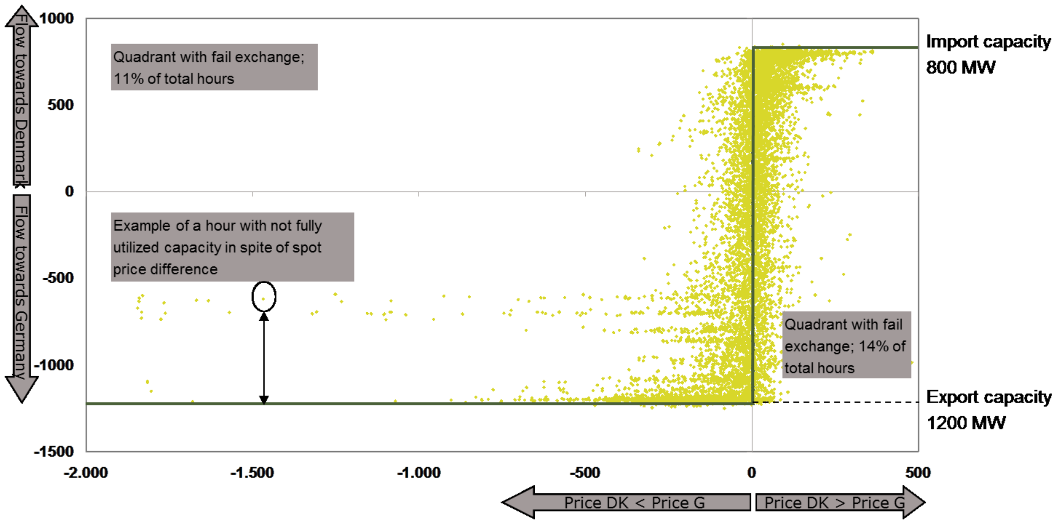


Figure 12: Exchange between Denmark and Germany in 2006 (8760 hours), when explicit auctions were still used in the day-ahead market (before price coupling of the Nordic countries with Germany)

After price coupling (i.e. primarily through the use of implicit auction of the inter-connector capacity) has taken place between the Nordic countries and Germany a much more valuable use of the interconnector takes place. This is depicted in *Figure* 13 (for year 2013). It shows exchange of energy in the "wrong" direction in only 3.5% of the year. These situations represent a welfare loss.

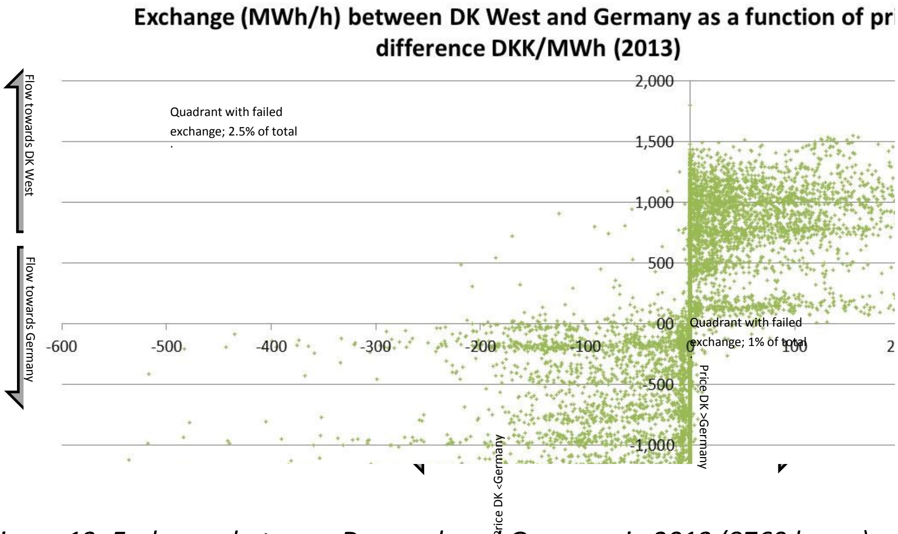


Figure 13: Exchange between Denmark and Germany in 2013 (8760 hours)

In Figure 14 below an overview is given with respectively the percentage of hours in the year with flow the “wrong” way and the associated welfare loss in million Euros. The welfare loss is calculated as the price difference between the two price zones (Germany and Denmark west) times the transferred power quantity[1]. The market coupling started in November 2009 thus 2010 was the first year with full effect of the market coupling. This clearly shows in the change from 2009 to 2010 in Figure 14 where the welfare loss is almost removed as a consequence from 2010 and onwards. In other words a large welfare gain has been obtained from changing the use of the interconnector in 2010 and onwards.

Year	Percentage of hours in the year with flow the "wrong" way	Welfare loss (Mill Euro)*	Approximately Export / import MW Cap.
2006	24%	-5.1	800 / 1,200
2007	29%	-8.3	1,000 / 1,600
2008	24%	-7.2	800 / 1,600
2009	24%	-4.2	1,000 / 1,600
2010	8%	-0.1	1,100 / 1,500
2011	2%	-0.1	1,100 / 1,500
2012	2%	-0.1	1,000 /1,500
2013	4%	-0.4	1,500 / 1,500
2014	8%	-0.2	1,500 / 1,500

Figure 14: Exchange between Denmark and Germany in each year (8760 hours) and the associated welfare loss

[1] It could be argued that the welfare loss is actually twice as large since the loss could be calculated as the flow could go in the right direction from the high to low price zone.

As shown in Figure 14 the average welfare loss in the period 2006-2009 were app. 6 million Euros and the export/import capacity averaging 1.2 GW. This represents a welfare loss pr. 1 GW of around 5 million Euros. By developing the power market structure towards increased market coupling in Europe large welfare gains have been obtained through the way the interconnectors are used. This welfare gain has taken place and still takes place from all interconnectors in Europe that have gone or will go from being used through explicit auctions to being auctioned implicitly, as part of a move to a market coupling of price zones. If the above specific welfare gain is somewhere representative as the average gain obtained from moving to a market coupling then there is a massive gain on an European or Chinese overall level. For example assuming interconnector capacity of 500 to 1,000 GW used in a none optimal way - as the case was in 2006-2009 for the interconnector between Denmark and Germany – the welfare gain could be as large as 2,500 to 5,000 million Euros pr. year (this is naturally a very high level and extremely crude estimation, but illustrates the large welfare gain potential that can be obtained through a more efficient and valuable use of the interconnectors.

Sub conclusion

If 25% (of the total hours over a year) represent an general average of loss-making historic use (around 10 years ago) of interconnectors in Europe it clearly shows that a very large welfare gain has been obtained by developing the market from a regional not price-coupled markets with explicit auctions to congestion management by implicit auctions of transmission capacity. In order words a change in the pricing mechanism (explicit vs. implicit auction) and consequently the use (flow direction per hour) of the interconnectors have very large welfare impact.

The third concept of congestion management is counter trade or re-dispatching. In contrast to implicit auctions and explicit auctions, congestions are not managed day-ahead but through counter trade of generation after gate closure in the day a-head market, typically in the real time regulating power market. This type of congestion management is needed to apply, when congestions occur inside the price zones and not solely at the borders to other zones. When counter trade becomes a structural and permanent issue, a review of the bidding zones layout should be considered.

4.2.2 Intraday European markets

The intraday markets facilitate continuous trading from 36 hours before and up to one hour before delivery (real time). All remaining transmission capacity from the day-ahead market is available for intraday trading and market participants in the intraday market can obtain transmission capacity free of charge on a first-come first-served basis. *Figure* 15*:* Outline of time schedule for intraday marketsoutlines the time schedule for intraday markets.

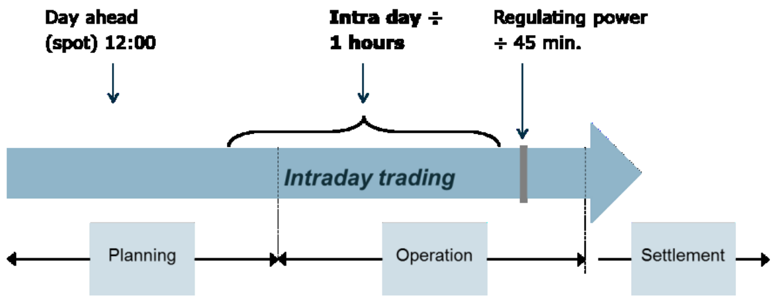


Figure 15: Outline of time schedule for intraday markets

The purpose of intraday trading is to make it possible for market participants to trade internally and thereby fine-tune their positions in the market. E.g. a production balance responsible (e.g. a generator company) with a large portfolio of wind has bid into the day-ahead market based on 12-36 hours of forecasted wind power. As time comes closer to real time the wind forecasts change and become more precise. Therefore it might be beneficial to trade the difference in the intraday market, instead of waiting for the TSO to handle the imbalance in the real time TSO-market. All market participants can place orders of buying or selling and the trade is anonymous and is facilitated by a regional power exchange.

Today there exist several regional non-connected intraday markets in Europe. The Nordic countries plus the Baltics comprise one regional intraday (ID) market area, see *Figure* 16.

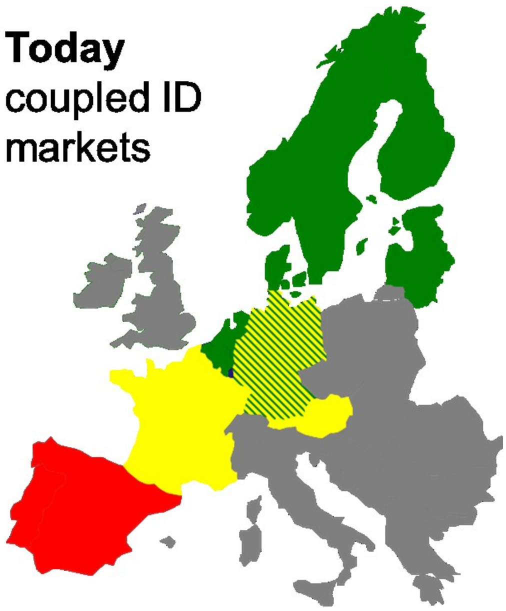


Figure 16: Today's regional intraday (ID) markets

A European project- XBID (Cross border intraday markets) – on the integration of the Intraday markets is ongoing. The XBID project is expected to go live in 2017/18 thereby coupling (most) of the European intraday markets.

4.2.3 Regulating power markets

In the regulating power market, TSO's buy up- or down regulation power to create balance in their respective balancing areas. Market participants can give in bids (generation/demand) to the market until about an hour (45 min in the Nordic market) before delivery. The bids must at maximum have an activation time of 15 minutes.

The common Nordic regulating power market was started in 2002 and operates on a common IT platform (NOIS). The major proportions of the bids are voluntary, while a minor part of the Danish bids is being paid an option price for being available. This option price is determined through daily auctions in the manual capacity reserve market. The common Nordic regulation market means that for example an up-regulation bid from Finland can be applied for up-regulation in Denmark etc.

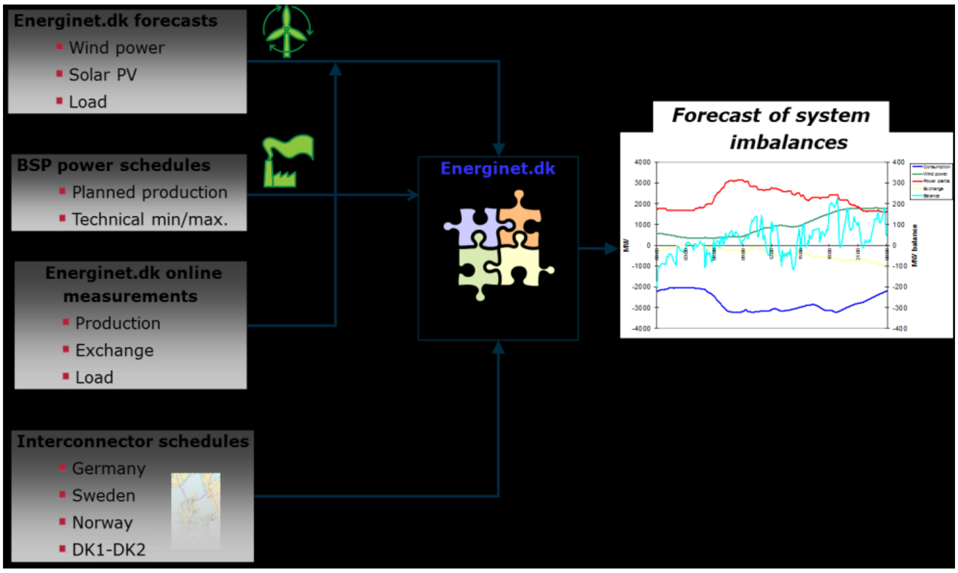


Figure 17: The TSO task of securing the balance in real time

Figure 17 shows the working procedures of a TSO (Energinet.dk) for securing the balance in real time. The TSO's planning system has the following input:

- The TSO carries out forecast for wind, solar PV and load. The forecasts are updated on routinely basis.
- Based on the day-ahead clearing, the market actors make their "generator" schedules for the coming day and forward them to the TSO. The schedules are currently updated with trades in the intraday-market.
- Online measurements of production, load and exchange
- The TSO receives the interconnector schedules from the Power Exchange

Based on this input the TSO carries out forecasts of the unbalance in his balancing area for the hours ahead of real time (adding production, demand and import/export, see light blue curve in *Figure* 17). The objective for the TSO is to minimise the unbalance and for that purpose it trades and activates the cheapest bids in the regulating power market. Energinet.dk's philosophy is to be in an up-front position with duly activating bids in the regulating power market, thereby leaving fewer amounts to be balanced by more expensive automatic reserves.

The largest driver for unbalance in Denmark is by far the uncertainty of the future wind power production. Forecasting errors with regard to wind comprise approx. 65% of total yearly imbalances handled in the regulating power market.
The challenge follows from *Figure* 18. A forecast error of 1 m/s in wind speed will on average cause an imbalance of 550 MW corresponding to about 10% of installed wind power capacity and 25% of minimum load.

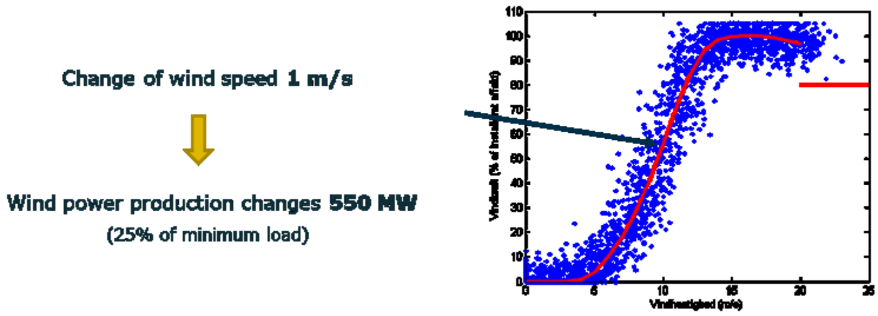


Figure 18: Future wind power generation is hard to forecast (Denmark)

Pricing in the regulating power market is normally closely linked to the prices in the day-ahead market. This is shown in *Figure* 19 with two examples. In the upper part of the figure the actual wind power is larger than assumed in the day-ahead market. The system therefore needs down-regulation. The bids in the regulating power market should therefore be expected to lie in the "downwards" direction on the supply curve, meaning that downward regulation price is lower than day-ahead price. In the lower part of the figure up-regulation is needed and the bids for up regulation are similarly expected to be more expensive than the day-ahead price (moving upwards along the supply curve).

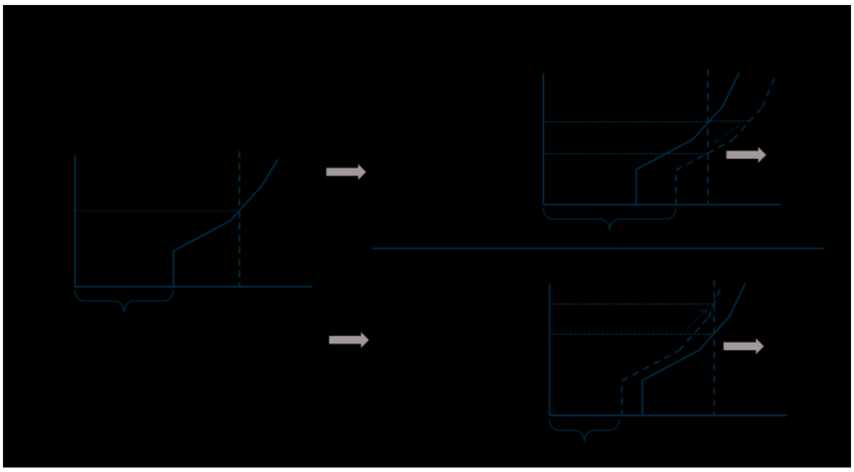


Figure 19: Pricing in regulating power market

Settlement of unbalances

When the operating day is over, the market participants are settled according to the deviations in their plans for the day; e.g. an electricity supplier has forwarded a plan with specific power consumption in a given hour and at the end of the day it shows up, that the consumption has deviated from this estimate. This unbalance is settled with the TSO. The same applies to a "generator" having forwarded a plan for generation, which deviates from the actual generation.

In the Nordic region, market actors responsible for deviations in trade and consumption are settled according to the regulating power price (one-price model) paid by the TSO in the regulating power market.

However, "generators" in the Nordic market are settled according to the "two-price model", which implicates that a generator with a deviation that reduces the system unbalance is settled by using the day-ahead price, while a generator with a deviation that increases the system unbalance is settled by using the regulating power price.

Other regions in Europa may have other preferences regarding "one or two-price models" for settlement. The Nordic two-price model for "generators" is used in order to incentivise generators to give in bids to the regulating power market.

4.2.4 Market for ancillary service

Ancillary services are services that ensure reliability of the power system in general and support the transmission of electricity from generation to customer loads.

The products include:

- Primary reserves
- Secondary reserves
- Manual reserves and regulating power
- Reactive power
- Voltage support
- Short-circuit power
- Inertia
- Black start recovery

For this report we will confine ourselves to the first three services and *Figure* 20 shows a classic representation of how they are used after a severe disturbance, e.g. tripping of a generator.

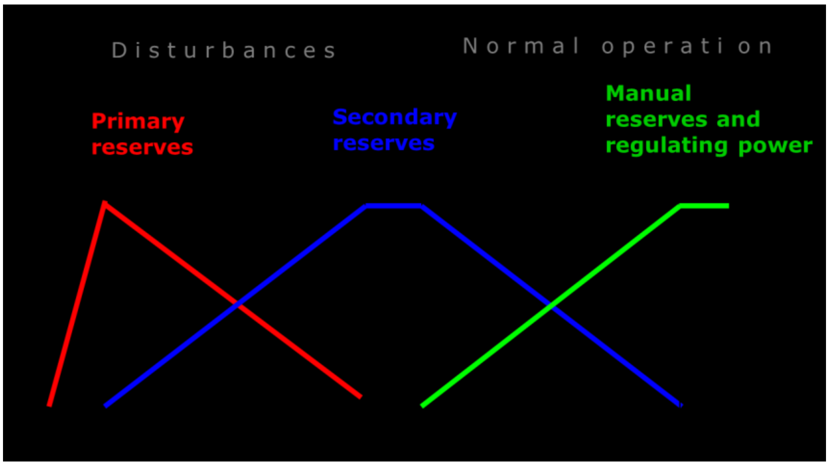


Figure 20: Function of reserves

The primary reserve FCR-A (frequency containment reserve-automatic) is activated for stabilizing the frequency.

The secondary reserve FRR-A (frequency restoration reserve-automatic) is an automatic 15-minutes power regulation function, delivered by generation and/or consumption units that react to an online regulation signal sent by the TSO. The function is to release the primary reserve, to restore the frequency to normal value and to restore any imbalances at the borders.

Manual reserve and regulating power is production and consumption units that are manually activated by the TSO via the regulating power market. The manual reserves FRR-M (frequency restoration reserves-manual) take over from secondary reserves and bring back the system to normal operation.

Dimensioning of reserves

Primary reserves (FCR-A) are dimensioned on basis of the largest normative incident in the synchronous system (n-1). For the central European system this incident is 3,000 MW. This amount is shared between the balancing areas/countries according to yearly electricity generation.

Restoration reserves (FRR-A and FRR-M) must be sufficient to make each area able to keep its balance in 99% of the time without having to utilise system reserves outside the area. This is a requirement in the future European operational network codes, which are now ready to enter into the EU-adoption process with succeeding national implementation. Besides, the restoration reserves must as minimum be able to cover for loss of largest unit within the area (n-1).

Procurement of reserves

Figure 21 outlines the main characteristics of Energinet.dk's procurement of reserves. Primary reserves and manually reserves are purchased on daily auctions, while secondary reserves are procured on a monthly basis.

- **Primary reserves**
  - Daily auctions (4-hour blocks).
  - Separate bids for up and down regulation.
  - Minimum bid size: 0,3 MW.
- **Secondary reserves, LFC (DK1 only)**
  - Monthly tenders.
  - Symmetric bids.
  - Minimum bid size: 1 MW
- **Manual reserves**
  - Daily auctions (hour by hour).
  - Separate bids for up and down regulation.
  - Minimum bid size: 10 MW.

Figure 21: Purchase of reserves

Compared to the day-ahead and intraday markets the reserve markets in Europe are typically national. In many countries reserves have until now solely been purchased from domestic providers. However the trend has lately changed towards broader international markets.

Energinet.dk's strategy for the coming years regarding ancillary services is based on the following pillars:

- International outlook
  - Ancillary services from abroad
  - Danish providers may sell services abroad
- Competition
  - New technologies and vendors can participate in the market
  - Liquidity and "correct prices"
- Transparency
  - Energinet.dk will provide more transparency about internal processes and the market

The most important concrete initiatives in the strategy are:

- Participate in common market of primary reserves with Germany, Netherlands, Austria and Switzerland
- Facilitate and work for a common Nordic market on secondary reserves
- Trans-boundary trading of secondary reserves with Germany

- Trading of manual reserves over the borders of different synchronous areas
- Investigate the technical feasibility and economic opportunity of trading frequency reserves over DC connections

4.3 ENTSOE's role in creating flexibility on the European system

This section gives a very brief overview of the way the European network is coordinated with respect to flexibility. The aim is not to provide enough details for the reader to be able draw direct conclusions regarding the Chinese system after reading it, but rather to inspire the reader to read the supporting ENTSO-E-documents.

The presented details have been selected based on the discussions during Sprint 3 on flexibility and the experiences obtained during the negotiation of a new Nordic System Operation Agreement to comply with the LFC&R network code.

4.3.1 Network codes

To facilitate the harmonization, integration and efficiency of the European electricity market, the European Commission (EC) has mandated ENTSO-E to draft a set of network codes as shown in Figure 22.

Figure 22. Overview of the proposed European Network codes (May 20, 2015)[2]

It will be an advantage for China to have a set of similar rules to ensure a secure and efficient integration of renewable energy across the different provinces.
The actual network codes are written as law texts with focus on unambiguity. To gain an understanding of the essence and the background of the requirements, it is advisable to read the supporting documents[3]. It should be noted that none of the network codes have yet been finally approved by the EC. Recently, the EC has

[2] http://networkcodes.entsoe.eu/

[3] E.g. http://networkcodes.entsoe.eu/wp-content/uploads/2013/08/130628-NC_LFCR-Supporting_Document-Issue1.pdf

for example decided to merge the operational codes into one common guideline. The codes should therefore at this state only be used as inspiration.

The network codes which are most relevant in terms of power system flexibility are “Load Frequency control and Reserves” (LFC&R) and “Electricity Balancing” (EB). Where LFC&R describes the technical requirements, EB describes the market requirements.

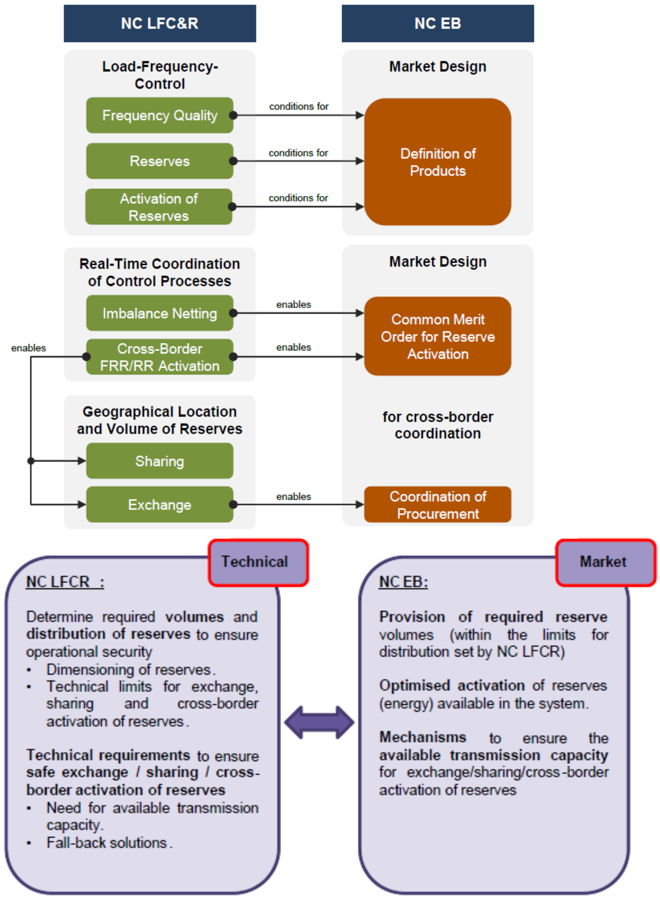


Figure 23. Relationship between LFC&R and EB

4.3.2 Control process and control structures

4.3.2.1 The overall European control process

The balancing of a large power system like the Chinese and the European requires coordination between the different regions. The Chinese system is dispatched through 5 hierarchical levels of control.[4]

In Europe, the hour by hour energy dispatch is done directly for the market participants through day-ahead and intraday markets. However, to maintain a stable frequency at all times, the TSOs control the frequency in cooperation. Figure 24 shows the principle of frequency control in the ENTSO-E-area.

[4] Zhang Lizi, North China Electric Power University, presentation on April 28th 2015

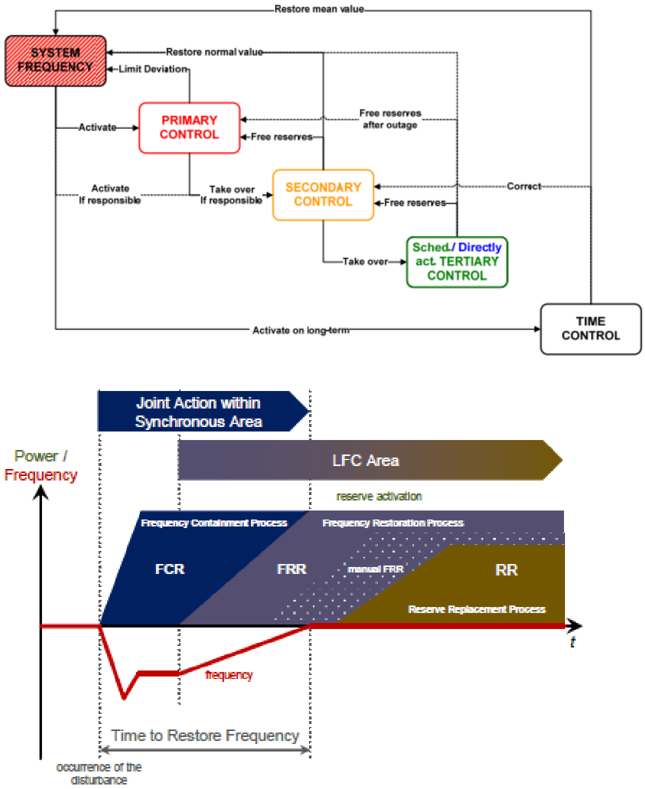


Figure 24. The principle of primary, secondary and secondary control actions[5].

<u>Primary control</u>

The primary control reserves are denoted “Frequency Containment Reserves” (FCR). They comprise local control action on individual plants which is proportional to the frequency deviation.

These reserves must start ramping immediately after a frequency disturbance. If a production unit trips, all the units in the synchronous area will compensate for the lost production, because they see the same frequency. This kind of control is used universally in all larger power systems around the world.

<u>Secondary control</u>

To ensure that the FCR reserves are available for the next event and to reduce the power flows in the system, secondary reserves are activated. Secondary reserves are denoted “Frequency Restoration Reserves” (FCR). They consist of two different types. FRR-A are automatic reserves which can be activated within a few minutes e.g. through a SCADA system. In China, this kind of reserves are denoted AGC, and all new production units must be able to perform AGC control[6]. FRR-A reserves are usually activated through a Load Frequency Controller (LFC) which

[5] http://networkcodes.entsoe.eu/wp-content/uploads/2013/08/130628-NC_LFCR-Supporting_Document-Issue1.pdf

[6] Zang, during presentation *release of market mechanisms power system flexibility* on CVIG meeting April 29 2015

either compensates for the imbalance of an LFC-area or the stationary frequency deviation of a synchronous area with only one LFC area . FRR-M reserves are manually activated reserves which have a startup time of 15 minutes. These reserves are cheaper than FRR-A reserves. It is therefore the task of the dispatcher with help from the forecasting and scheduling systems to proactively order the cheaper reserves and thereby reduce the total costs.

Tertiary control

Tertiary control reserves have an even longer start up time than secondary reserves. The purpose of these reserves is to ensure that the relatively fast secondary reserves are not occupied by static imbalances. These reserves are denoted "Restoration Reserves" (RR).

Time control

Time control controls the integral of the frequency. Earlier, some clocks were synchronized by the grid frequency. Today, the time control mainly serves to ensure that the average frequency is 50 Hz. The advantage of this approach is that the energy output of an FCR controller will be zero, because it will regulate upwards as often as it regulates downwards. One drawback of the process is that the frequency during the time adjustment periods will be different from 50 Hz which increases the risk in case of a large outage.

4.3.2.2 Choice of control structure

As mentioned in the previously, the different control processes and responsibilities are related to different areas in the network.

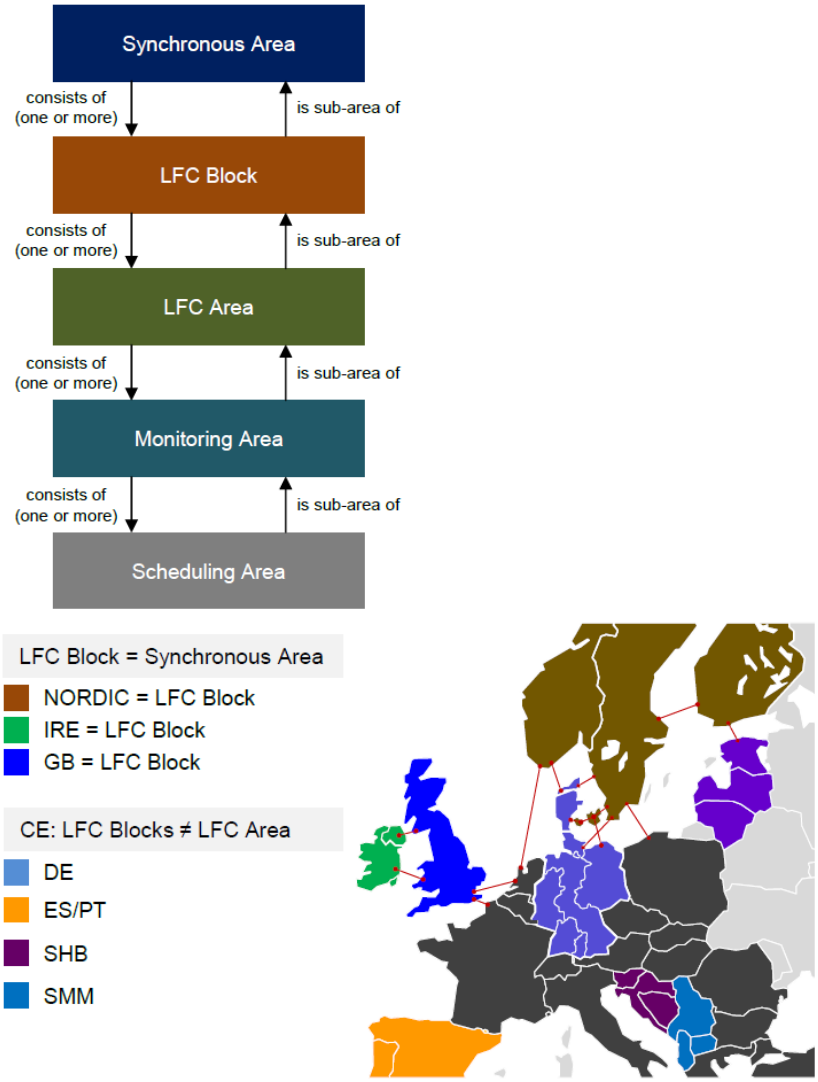


Figure 25. Hierarchical control structure

Obligations	Scheduling Area	Monitoring Area	LFC Area	LFC Block	Synchronous Area
Scheduling	MANDATORY	MANDATORY	MANDATORY	MANDATORY	MANDATORY
online calculation and monitoring of actual power interchange	NA	MANDATORY	MANDATORY	MANDATORY	MANDATORY
calculation and monitoring of the Frequency Restoration Error	NA	NA	MANDATORY	MANDATORY	MANDATORY
Frequency Restoration Process	NA	NA	MANDATORY	MANDATORY	MANDATORY
Frequency Restoration Quality Target Parameters	NA	NA	MANDATORY	MANDATORY	MANDATORY
FRR/RR Dimensioning	NA	NA	NA	MANDATORY	MANDATORY
Frequency Containment Process	NA	NA	NA	NA	MANDATORY
Frequency Quality Target and FCR Dimensioning	NA	NA	NA	NA	MANDATORY
Reserve Replacement Process	NA	NA	OPTIONAL	NA	NA
Imbalance Netting Process	NA	NA	OPTIONAL	NA	NA
Cross-Border FRR Activation Process	NA	NA	OPTIONAL	NA	NA
Cross-Border RR Activation Process	NA	NA	OPTIONAL	NA	NA
Time Control Process	NA	NA	NA	NA	OPTIONAL
Mandatory cooperation to fulfil obligations of	Monitoring Area	LFC Area	LFC Block	Synchronous Area	NA

Figure 26. Responsibilities on different levels in the power system

<u>Synchronous area</u>

Like China, the European grid has several synchronous areas. A synchronous area is an area which is AC interconnected, i.e. all machines are running synchronously. More synchronous areas can be connected through HVDC connections. Because the entire area has the same frequency, all TSOs in the synchronous area has a joint responsibility to ensure that sufficient FCR-reserves are available to ensure stable operation. As illustrated in Figure 27, the amount of FCR must in the future be chosen in such a way that the likelihood of exhaustion in case of simultaneous events is less than one in 20 years

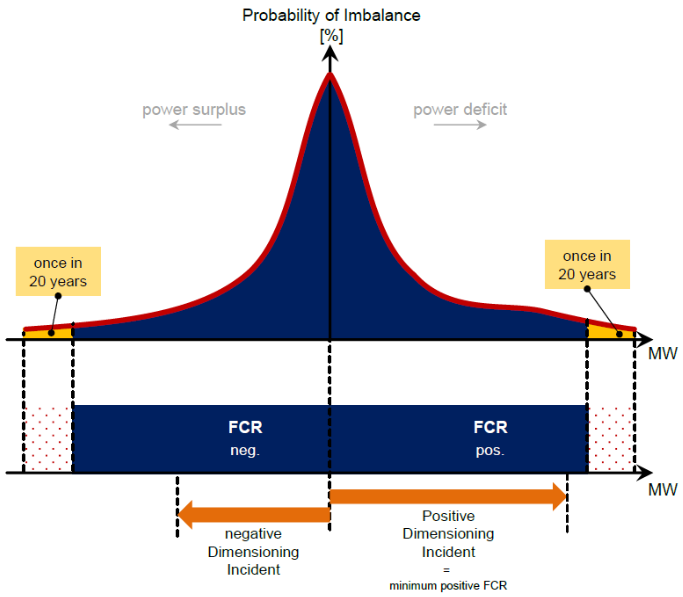


Figure 27. FCR dimensioning

It is, however, not completely clear at the present time, how to do the probabilistic calculation. Today, the dimensioning is based on a dimensioning incident which is 3,000 MW corresponding to two large plants in Continental Europe. Due to the size of the Chinese system and the amount of generators which are always available, FCR does not seem to be a problem there. Even when a very large part of the power production will come from renewable energy, the hydro plants will be able to provide the required primary control.

<u>LFC-Block</u>

As shown in Figure 26, the LFC blocks are responsible for the dimensioning of restoration reserves. That way it can be ensured that the total exchange with the other LFC blocks can always be restored.

The restoration reserves must be dimensioned in such a way that the likelihood of exhaustion of the reserves is less than 1 %, and so that the frequency control targets can be met.

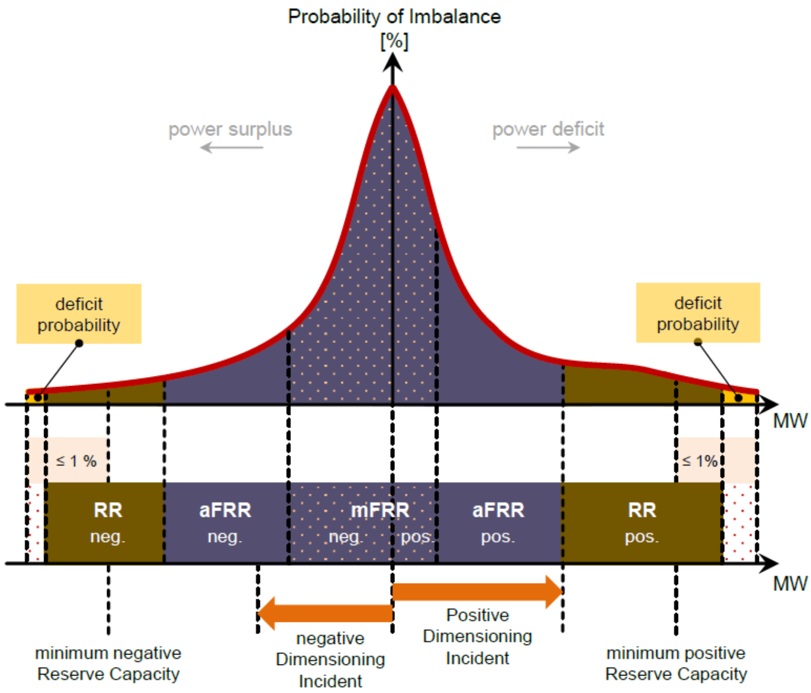


Figure 28. Restoration of reserves

The size of LFC block has some implications on the requirement for reserves in the system and thereby the cost of operation and the security. By choosing a large LFC block, the pool of reserves can be shared over a larger area, which reduces the cost. On the other hand, this also means that activation of reserves can cause large power transfers. To avoid overloading in the network, grid capacity must be reserved for the possible transfer of reserves.

4.4 Sub conclusion

A competitive and auction based ancillary services market is a cost efficient way of secure balancing and reserve capacity and services. Some of the main prerequisites for a well-functioning cost efficient ancillary services market are:

- Clear signals to the ancillary services suppliers regarding prices and demand for quantities for each product type and for each time frame.
- An integration of local/regional markets into a larger market as has happened all ready with the Nordic regulating power market (NOIS), and is planned for all the European countries in the XBID

In an European context ENTSO-e has already made an ambitious system, i.e. set of technical and administrative rules, for integration of re over region with different power system set-up’s that can inspire China

Although the Chinese power system is larger than the European system, the two have a lot in common. The different provinces in China can be compared to the different countries in Europe. It is therefore likely that some of the well proven European control and governance principles can be applied in China.

4.5 Power Price Development

4.5.1 System price and its development (Nordic countries)

The Nordic system price is the common wholesale day-ahead price in the Nordic area, if there were no transmissions congestions in the area covered by the four countries Norway, Sweden, Finland and Denmark. Hence the system price is a virtual price. However the system price is an important concept because this price is the underlying reference for most of the Nordic financial power contracts. The system price thus reflects the price if there was no constrains or limited interconnector capabilities.

Figure 29 shows the development of the Nordic system price (moving weekly averages) over 20 years from 1993 (Norway) until 2013. It follows that the price evolution has been highly volatile. As hydro power is the dominating technology for power generation in the Nordic system price area (about 50% of total installed capacity) the hydrological conditions are very important driver for the price. Also temperatures during winter are important, as electricity demand rises with low temperatures, especially in Norway, Sweden and Finland. Therefore cold and dry winters may cause high system prices with weekly averages around 100 EUR/MWh. Otherwise in wet years with abundant water resources, the system price has been down to 10 EUR/MWh, see *Figure 29*.

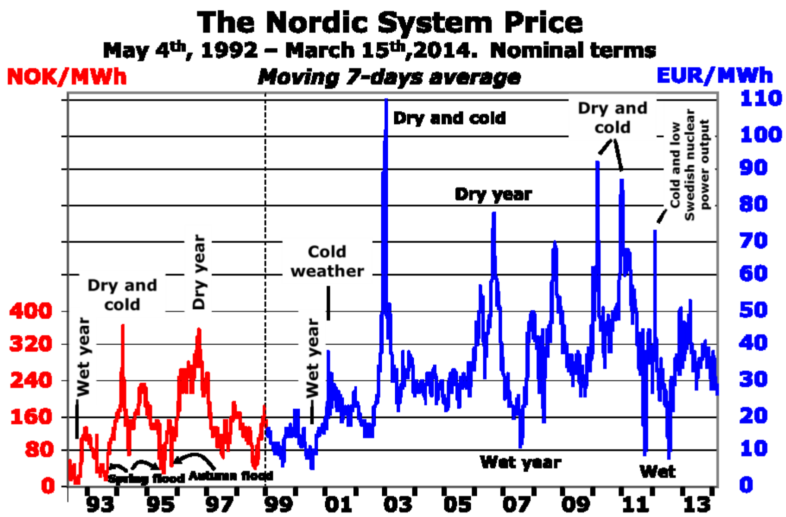


Figure 29: The Nordic System price development 1993-2013 (ref. Houmøller Consulting)

The prices in *Figure 29* are moving weekly averages. To illustrate the volatility within the week *Figure* 30 depicts the zonal day-ahead market prices in Western Denmark (DK West) in a relative extreme week in January 2014. The variation in prices is high and the main driver is the huge variation in wind power (the green area of the figure) and thereby import/export out of the area. In the start of the week (Tuesday) the wind power generation is very limited, import is necessary and the price moves up to 70 EUR/MWh. In the weekend the wind power dominates the supply profile, export is prevailing and prices drop to 0 EUR/MWh.

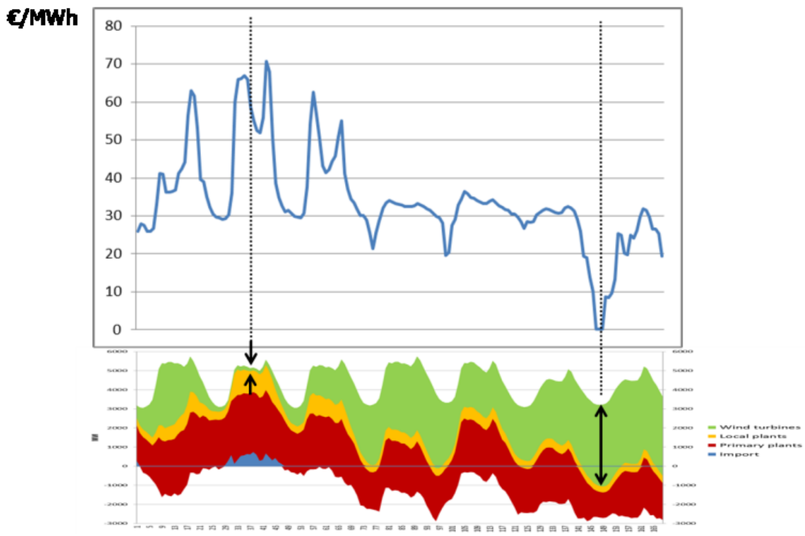


Figure 30 Dynamics of hourly spot prices in Denmark during a week in January 2014. The main driver for volatility is the huge variation in wind power.

4.5.2 Bidding and price areas

For each Nordic country, the national TSO decides which bidding areas the country is divided into. Today there are five bidding areas in Norway. Eastern Denmark (DK East) and Western Denmark (DK West) are always treated as two different bidding areas. Finland, Estonia, Lithuania and Latvia constitute one bidding area each. Sweden was divided into four bidding areas on 1 November 2011, see *Figure* 31.

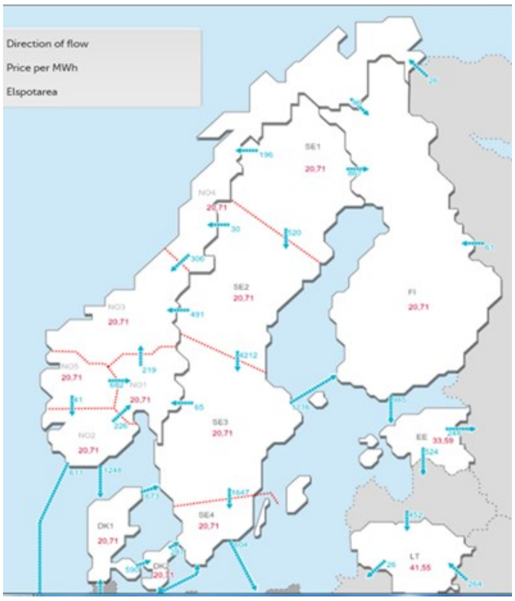


Figure 31: Bidding/price zones in the Nordic market

The different bidding areas help indicating constraints in the transmission systems, and ensure that regional market conditions are reflected in the price. Due to bottlenecks in the transmission system, the bidding areas may get different prices, called area prices. When there are constraints in transmission capacity between two bidding areas, the power will always flow from the low price area to the high price area, which is the optimal solution from a socio-economic welfare point of view, conf. section 4.2.1, Figure 5 and Figure 6.

If there are constraints <u>inside</u> a price area, the day-ahead scheduling will not be able to handle the congestions, as only transmission lines at the borders between price zones are going into the market clearing process as described in section 4.2.1. The congestions inside price areas are treated via counter trade/re-dispatching. When specific cuts within a bidding zone go from being temporarily to permanently congested, a reconfiguration of the layout of bidding zones should be investigated: the objective should be to localise the congested cuts at the borders between the new price areas, thereby making the transmission constraints transparent in the market clearing process. As mentioned this happened to Sweden in 2011.

When moving to the European market outside the Nordic area, the price zonesareas are very large. For central European countries the existing configuration of bidding zones is as follows (the number in brackets reflects the number of the bidding zones): Belgium (1), France (1), Germany, Austria and Luxembourg (1), the Netherlands (1), Denmark (DK West) (1), Czech Republic (1), Hungary (1), Poland (1), Slovakia (1), Slovenia (1), Switzerland (1) and Italy (6).

This configuration is the result of the historical approach of the national electricity markets rather than the outcome of appropriate assessments at regional or pan-European level. The price zone structure in Europe in currently under review.

One important aspect of European bidding zones being too large is, that the results of the joint day-ahead market scheduling of generation and transmission deviate from the actual physical flows in the strongly meshed European transmission grid. This challenge is illustrated in *Figure* 32.

When power is transported from e.g. north of Germany to southern Europe the power flows along multiple routes due to the heavy meshing of the transmission grid in central Europe. The diversified flow is not fully reflected in the relative simple market setup with large bidding zones and few transmission lines between bidding zones. This results in deviations between the market solution (blue numbers in *Figure* 32) and actual flows (green numbers). The transit through Slovakia in the actual hour is 2,166 MW, while the market result is 1075 MW. Such incidents can hamper the security of supply.

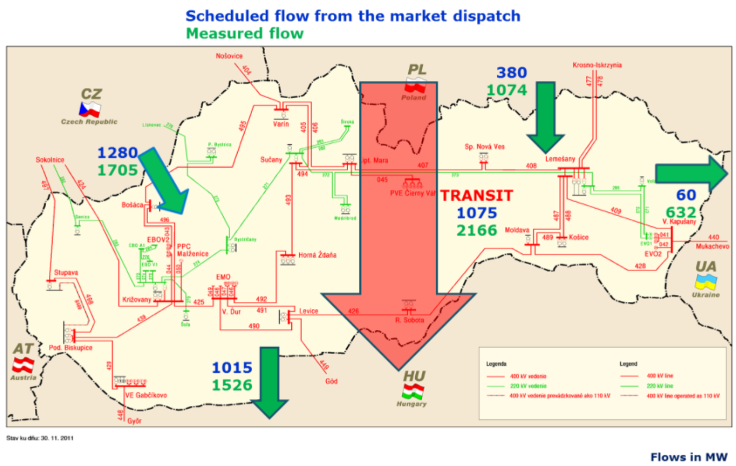


Figure 32: Deviations between market scheduling results and the actual grid flows. Example from Slovakia. Green=actual flows Blue=market flows

By reconfiguring the price zones of central Europe into smaller ones with additional transmission lines added between the new and smaller zones, it is expected that the abovementioned problem will be reduced significantly.

4.5.3 Zonal versus nodal pricing

As described above in section 4.5.1, the European market is based on dividing Europa into price zones with net transfer capacities (NTC) between the zones. The NTC values are estimated by the TSO's from power flow calculations.

By reconfiguring the price zones according to the main grid constraints, it is expected that the deviations between market scheduling and the physical flows will be reduced. The trend in Europe is to improve the zonal approach along this line.

However, there is a simplistic assumption inherent in the zonal model, which is that the model treats power flows in transmission lines as independent variables. In reality the flow in one line is dependent on the flow in other lines due to basic physical laws. To incorporate this dependency, one needs a representative model of the transmission grid and take the physical flow equations into account in the market scheduling.

In USA several market areas has introduced such market regimes called Nodal pricing or LMP, Locational Marginal Pricing. One well-known example is PJM Interconnection, which is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

LMP is the marginal cost of supplying, at least cost, the next increment of electric demand at a specific location (node) on the electric power network, taking into account both supply and demand offers and the physical flow equations of the grid. Thus nodal price is the LMP at a specific node.

LMPs are determined from the result of a security constrained optimal power flow dispatch (SCOPF). Each nodal price can be decomposed into 3 components:

- Marginal cost at a reference bus
- Marginal cost of transmission losses
- Marginal cost of transmission congestion due to binding constraints

From an academic point of view the nodal price market model is superior to the zonal model used in Europe. The drawbacks of nodal pricing are:

- Large amounts of grid data must be collected and updated
- The results are not easily understood and can be contra-intuitive
- Large companies in the market (generators, load-suppliers, traders) are favored because they have the necessary manpower to interpret the market and grid complexities

Recently several regional studies have been launched in Europe to improve the grid representation in future market scheduling. The studies look into the so-called "Flow Based" (FB) method, which is a hybrid of zonal and nodal models. FB is a way to keep the zones, but still take network constraint into account on a best practical means-approach. The idea is to describe how a change of the state of a zone impacts so-called critical network elements. One of the main problems with FB is to define a general optimal procedure for aggregating nodes into zones.

4.6 Securing sufficient generation capacity in Europe

4.6.1 Energy markets

In several EU countries there is a growing concern that energy-only electricity markets will not deliver sufficient capacity to meet electricity demand in the future. The main argument is the so-called "missing money" problem, with price spikes required to provide the revenue to justify new construction, but disappearing once additional capacity is added (if political will is sufficient to allow such price spikes in the first place). Large scale support and deployment of renewables (RES), producing at very low (or almost zero) marginal cost is leading to lower market prices, reducing the incentives for new investments that may be needed to ensure adequate flexible capacity for keeping the security of supply. In addition, decreasing market prices also push existing conventional power plants with relative high marginal costs out of the market as they no longer are profitable.

Market prices have further declined because the price of CO_2 in the European Emission Trading System (ETS) has collapsed, mainly due to the financial crisis .

Figure 33 shows the development of installed generation capacity in Denmark. During the last years there has been a drop in capacity of conventional power plants, while renewable energy capacity grows. This trend is foreseen to continue. The result is less flexible capacity available, while the need for this kind of flexibility is increasing.

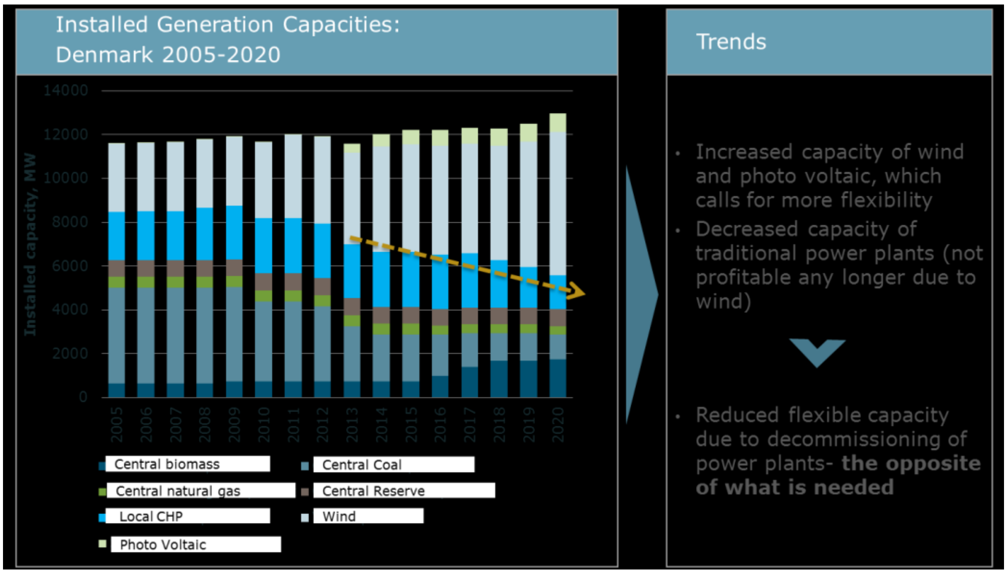


Figure 33: Development in flexible capacity

4.6.2 Capacity Remuneration Mechanisms (including strategic reserves)

As a response to the growing concern of future generation adequacy, a variety of Capacity Remuneration Mechanisms, CRMs have been proposed. UK has a capacity market, some countries as e.g. France and Italy are in the process of implementing capacity markets, and some countries have or plan to introduce other CRM's. Denmark is considering introducing a capacity reserve with starting in 2016.

Figure 34 illustrates the function of the planned strategic reserve of 200 MW. The capacity will be applied if the supply and demand cannot meet in the spot market. The reserve or part of the reserve will be added into the market at the maximum spot-market price (3,000 DKK/MWh) until the market can clear.

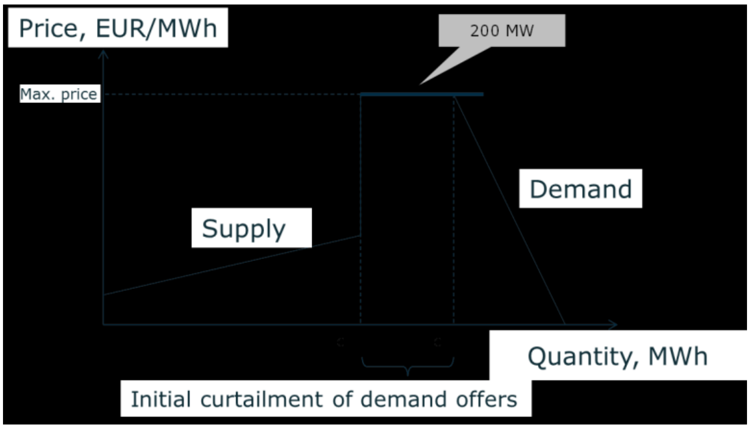


Figure 34: Function of strategic reserve (Denmark)

Energinet.dk plans to call for a tender on 200 MW of strategic reserves. Both supply and demand bids can participate. The reason for 200 MW is Energinet.dk's objective of maintaining the current high security of supply, independently of the large scale deployment of wind power. With 200 MW "strategic reserve" the LOLP (Loss of Load Probability) of 5 minutes per year with regard to system (capacity) adequacy can be maintained for the coming years 2016-2018.

Figure 35 compares "strategic reserves" with "capacity market". Payment to strategic reserves concerns a small amount of capacity while capacity market involves remuneration to every provider of capacity. Introduction of strategic reserves therefore has a limited consequence for the market compared to capacity markets.

	Strategic reserves	Capacity Market
Remuneration to	Small amount of capacity	Every provider of capacity
Motivation: Too little investments	Extreme situations	Market failure/missing money
Examples	Sweden and Finland	GB and France
Key questions	When shall the reserved capacity be used? What is the price when capacity is used?	Who defines the required level? What happens if the provider does not deliver when needed?
	Who can participate?	
Consequence for market	Minor change	Fundamental change

Figure 35: Difference between capacity reserves and capacity market

In 2014 Energinet.dk launched a project: "Market Model 2.0" together with the market stakeholders in Denmark to find the best possible future market design. The future market model should be characterized by:

- Being as simple as possible
- Contributing to stable economic and technical framework for market participants
- If possible, the market model should be neutral in regard to technologies

4.7 Advantages and disadvantages of liberalized power markets in Europe

The important advantages of liberalized power markets in Europe are:

- European-wide competition in generation and trading through market based scheduling of generation and transmission has led to significant gains in efficiency for the sector, as a whole and cheaper electricity prices for the consumers.

- The market provides important price and investment signals for building new generators and new infrastructure at the optimal time and at the optimal place.
- Market prices eliminate the economic losses associated with the old regulatory framework with cost-coverage.

The most important disadvantage is, that under the old regulatory framework with vertical integrated companies it was possible to carry out a joint planning of generation and transmission assets. The two parts of the system are interlinked and highly physical interdependent. With the liberalization the transmission and generation sectors were uncoupled into separated companies with separated ownership. This fact makes it difficult to achieve a common optimal development of transmission and generation. Besides decisions regarding generation assets are governed by commercial interests and company economics, while transmission asset decisions most often are based on socio economics (depending on the regulatory setup for TSO's).

4.8 Lessons learned for China

It would be possible to introduce market principles for scheduling of China's generators and transmission systems along the same track as done in Europe. The first step could be establishment of a day-ahead market covering the whole of China, and including the main transmission lines between the provinces. Like Europe, China could be divided into price zones, where the borders of zones should be defined according to existing bottlenecks in the transmission grid.

By letting the whole of China be included from the very start, China will achieve the benefits of a coordinated operation and optimization of available resources. Especially it is important to bring the different supply structures of the Chinese provinces into play. It is the European experience that great values can be gained by activating the interplay of hydro power, wind power and thermal power production in an efficient day-ahead market.

Based on present knowledge of China's power system, a zonal approach is recommended. This solution is safe to succeed and besides, it does not involve the same vast efforts of collecting and updating grid data as is needed by a "nodal price"-approach. At the same time the results of the market scheduling in a "zonal approach" are easier to interpret.

5. The European planning framework for transmission infrastructure

5.1 The role of ENTSO-E for planning of the European power system

ENTSO-E was formed according to a European Commission Regulation (EC 714/2009).

The objective of ENTSO-E is to ensure optimal management of the electricity transmission network and to allow trading and supplying electricity across borders in Europe.

One of the main tasks of ENTSO-E is, each second year to carry out a non-binding Community-wide 10 year network development plan.

Grid development is a vital instrument in achieving European energy objectives**,** such as security of electricity supply across Europe, sustainable development of the energy system with renewable energy source (RES) integration and affordable energy for European consumers through market integration. As a community-wide report, the TYNDP (Ten year network development plan) contributes to these goals and provides the central reference point for European electricity grid development.

5.2 Structure and tasks

Figure 3.1 gives some main data for ENTSO-E. In addition figure 3.2 gives an outline of ENTSO-E's main tasks.

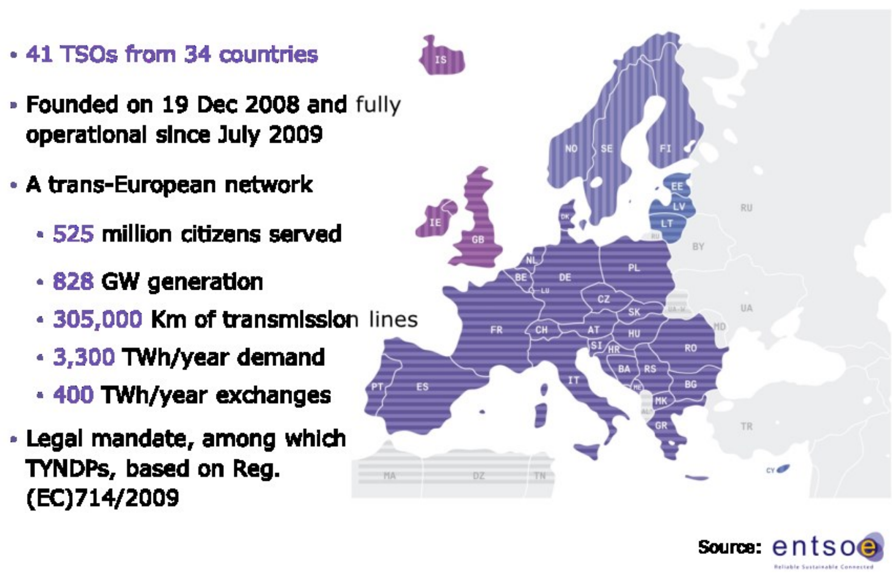


Figure 36: Main data for ENTSO-E

ENTSO-E’s mandate is to:

- Propose network codes
- Propose EU wide ten year network development plan (TYNDP)
- Ensure market integration EU-wide
- Support Research and Development
- Analyse the European Generation Adequacy Outlook (5/15 years horizon)
- Provide an integrated network modeling framework at the European level

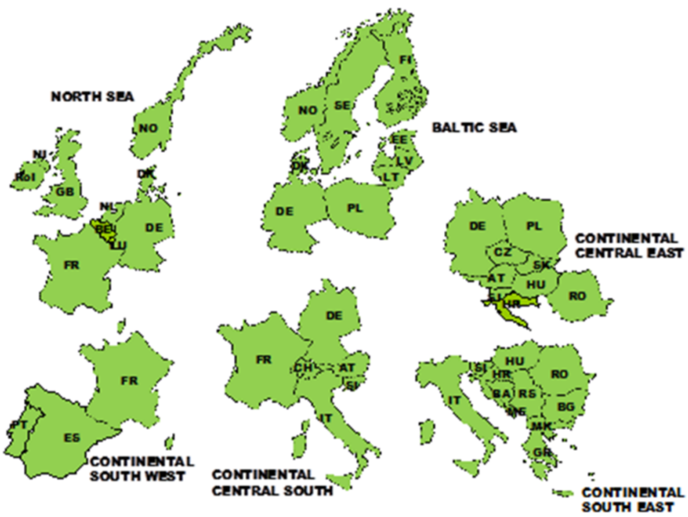


Figure 37: ENTSO-E division of Europe into six regional transmission planning areas

When it comes to transmission planning Europe is divided into six regional transmission planning areas as shown in *Figure* 37. The TYNDP is a result of an integrated approach between pan-European transmission planning and the regional planning in the six regions. The results of the regional planning are published every second year as Regional Investment Plans.

5.3 The Ten Years Network Development Plan- TYNDP 2014

The TYNDP is issued each second year. Until now three TYNDPs has been drawn up: TYNDP 2010, TYNDP 2012 and TYNDP 2014. In the following the description is confined to TYNDP 2014, which was published at the end of 2014.

Figure 38 shows important results from TYNDP regarding achievement of EU policy goals on Energy. The transmission plan opens for further integration of RES by 2030, corresponding to RES will cover 40%-60% of consumption depending on vision. Similarly the CO_2 emissions from the European power system will be reduced: In vision 1 the CO_2 emission will be 60% and in vision 4 only 20% of the emission in 1990.

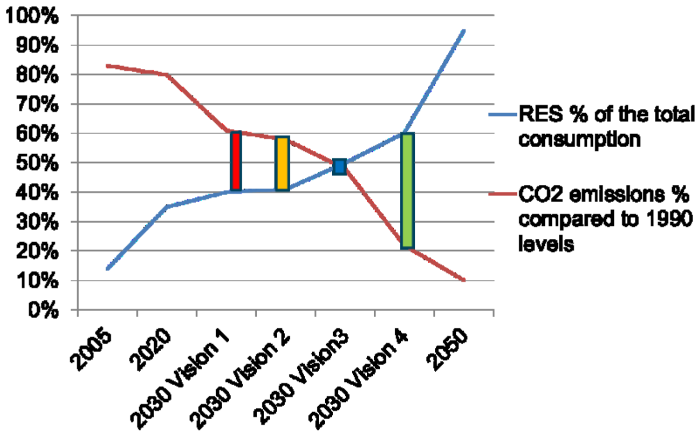


Figure 38: Energy policy goals require significant infrastructure increase (TYNDP 2014)

The TYNDP is a key tool in reaching the energy policy goals. Thus the plan deals with:

- Target capacities and transmission adequacy
- Challenges in building the necessary infrastructure
- Cost Benefit Analysis of new transmission lines
- Transparency on grid infrastructure
- Drivers for grid investment
- Market prices
- Bottlenecks

The planning methodology goes through the steps of

- Pan-European market modelling setting the European flow trends and setting the boundary conditions of the market modelling in the regional groups
- Regional market and grid modelling, which form basis for selection of new project candidates
- Assessment of project candidates according to the system wide CBA methodology

The TYNDP 2014 main goals are presented in compact form in Figure 39.

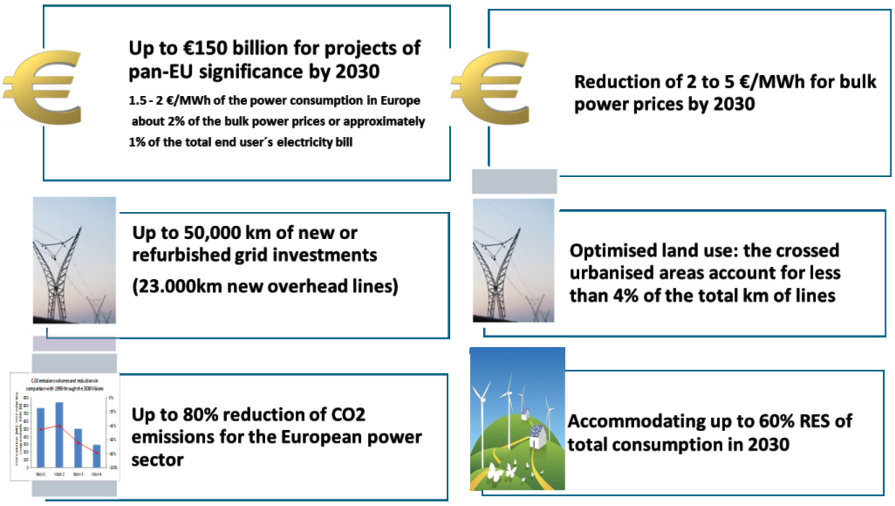
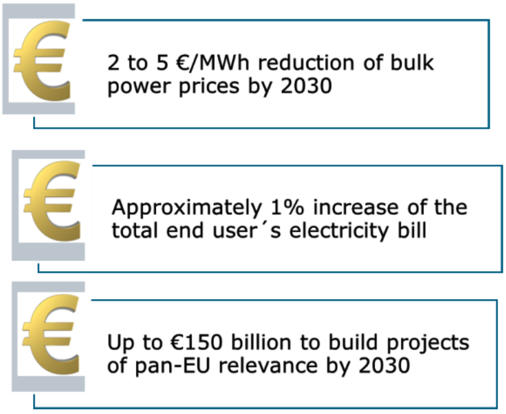


Figure 39: TYNDP 2014 main goals

The plan calls for EUR 150 billion investment by 2030 including about 50,000 km of new or refurbished transmission lines. The plan will reduce up to 80% of CO_2 emissions from the power sector compared to 1990 and make it possible to accommodate up to 60% coverage of consumption by RES. The directly impacted crossed urbanized areas account for less than 4% of the total km of lines.

The estimated impact of the plan is shown in Figure 40, that the investment costs are distributed on countries. The largest investments are in Germany and Great Britain. It follows that even if the bulk power price (wholesale market price) is reduced 2-5 EUR/MWh by 2030 and that the realisation of the TYNDP is expected to cause a 1% rise of the end-user's electricity bill.



AT	1.9	IE	2.0
BA	0.1	IS	0.0[1]
BE	2.0-4.0	IT	5.9
BG	0.3	LT	0.7
CH	1.6	LU	0.2
CY	0.0	LV	0.4
CZ	1.5	ME	0.1
DE	34.8-54.2	MK	0.1
DK	3.7	NI	0.5
EE	0.2	NL	3.3
ES	4.3	NO	7.9
FI	0.8	PL	1.9
FR	8.4	PT	0.7
GB	15.9-16.2	RO	0.5
GR	2.6	RS	0.4
HR	0.2	SE	3.6
HU	0.1	SI	0.6
		SK	0.3
Total		110-150	

Figure 40: Transmission investments per country

Driven by RES development concentrated at a distance from load centers, and allowing for the required market integration, **interconnection capacities would need to double on average by 2030**. Differences are however high between the different countries and visions. The implementation of the TYNDP will significantly improve the interconnection capacities cross Europe.

The TYNDP also defines so-called target capacities. For every boundary, the target capacities correspond in essence to the capacity above which additional capacity development would not be profitable, i.e. the economic value derived from additional capacity cannot outweigh the corresponding costs.

Transmission Adequacy shows how adequate the transmission system is in the future in the analyzed scenarios, considering that the proposed TYNDP projects are commissioned. It answers the question: “is the problem fully solved after the projects are built?”

The assessment of adequacy merely compares the capacity developed by the present infrastructure and the additional projects of pan-European significance with the target capacities. The result is displayed in the right hand side of figure 3.12: the boundaries where the project portfolio is sufficient to cover the target capacity in all visions are in green, those sufficient in no vision at all are in red, and others are in orange.

The left part of Figure 41 shows that the most critical area of concern is the stronger market integration to mainland Europe of the four “electric peninsulas” in Europe. The Baltic States have a specific security of supply issue, requiring a stronger interconnection with other EU countries. Spain with Portugal, Ireland with Great Britain, and Italy show a similar pattern. These are all large systems (50-70 GW peak load) supplying densely populated areas with high RES development prospects, and as such, they require increasing interconnection capacity to enable the development of wind and solar generation.

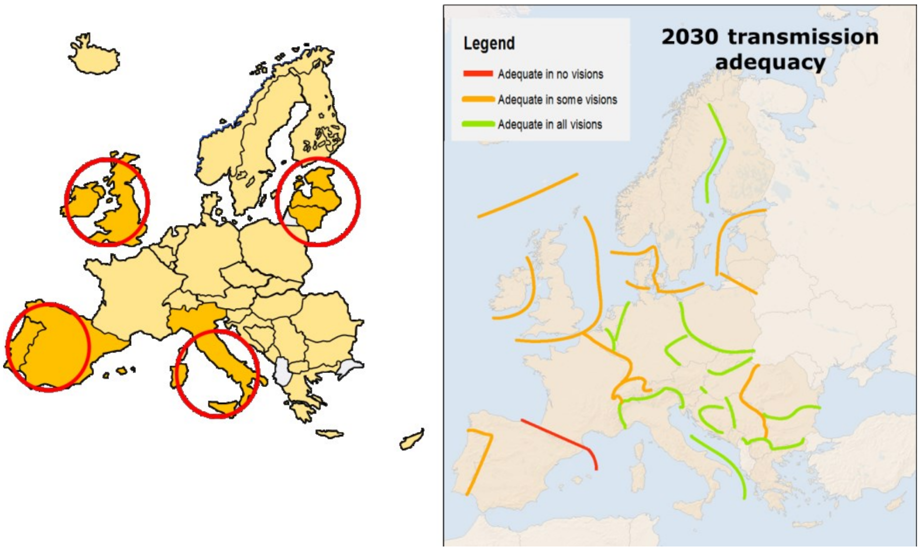


Figure 41: Right: Illustration of transmission adequacy; left: four "electric peninsulas"

Generally there are large challenges in building the necessary infrastructure according to the planned time schedules. Many projects are or will be delayed.

The three most important barriers are listed in figure 3.13: permit granting, public acceptance and financing. Especially the question of public acceptance is critical. People living along a future DC- transport corridor, e.g. from wind power parks in the north to main cities in south of Germany have no direct benefits of the infrastructure and are left with the visible impacts of big technical constructions in their backyard.

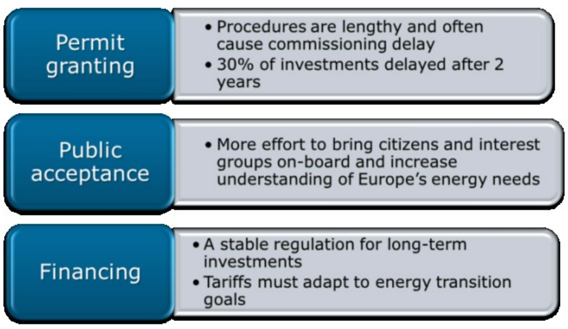


Figure 42: Important barriers for implementing infrastructure projects in due time

5.4 The drivers behind infrastructure development

The EU energy policy goals call for building of more transmission infrastructure. The main drivers for a stronger transmission grid are:

- Integration of RES
  - Transmission of large scale renewable power from resource areas in Europe to consumption centers
- Market efficiency by stronger transmission lines
  - Transmission between regions is a precondition for a well-functioning European internal market on electricity
- Security of supply
  - A strong transmission grid supports the exchange of power in stressed situations

From a grid planning point of view RES development is the strongest driver for grid development until 2030. The generation fleet will experience a major shift with the replacement of much of the existing capacities with new ones, most likely located differently and farther from load centers, and involving high RES development. This transformation of the generation infrastructure is the major challenge for the high voltage grid, which must be adapted accordingly.

Local smart grid development will help to increase energy efficiency and improve local balance between generation and load. Nevertheless larger, more volatile power flows, over larger distances across Europe are foreseen; mostly North-South driven by this energy transition, characterized by the increasing importance of RES development.

5.5 Evaluation criteria for transmission infrastructure

5.5.1 ENTSO-E system wide Cost Benefit Analysis (CBA)-methodology

All new transmission project candidates in the TYNDP planning process are assessed according to the same system wide cost-benefit methodology developed by ENTSO-E (ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects) and approved by the European Commission. The assessment includes the categories outlined in Figure 43.

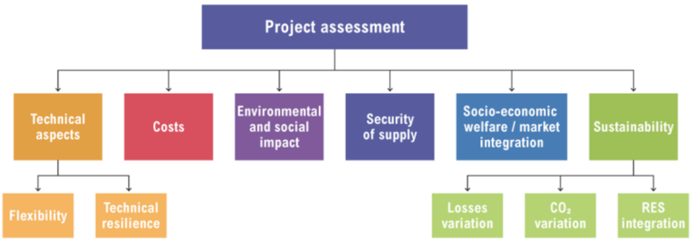


Figure 43: Categories of cost benefit assessment

The elements analysed in the CBA are:

- Grid Transfer Capacity (GTC) in MW. It is estimated by grid analysis.
- Security of supply is EENS (Expected Energy Not Served) or LOLE (Loss Of Load Expectancy)
- Socio economic welfare is defined as the sum of producer surplus, consumer surplus and congestion rents (see section 4.2 for a detailed description). Includes implicitly monetized values for CO_2 and RES integration (e.g. improved value of RES generation by reducing curtailment of wind).
- Losses are transmission losses (change in losses for the whole system)
- Costs are project costs and changes in other costs incurred by the project (except for losses)
- Technical resilience/system safety is the ability of the system to withstand increasingly extreme system conditions (exceptional contingencies). Semi-quantitative estimation based on KPI (key performance indices) scores
- Flexibility/robustness is the ability of the proposed reinforcement to be adequate in different possible future development paths or scenarios. Semi-quantitative estimation based on KPI (key performance indices) scores

5.5.2 Energinet.dk- business case evaluation of a new interconector

General principles

Energinet.dk carries out investment analyses for new interconnectors on basis of socio economic welfare calculations very much in line with ENTSO-E's CBA methodology. The important criterion for approving an investment is a positive business case for Denmark. Benefits must be larger than costs.

The analyses take as basis Energinet.dk's analysis presumptions for power systems in Denmark and neighboring countries. Instead of investigating four visions or scenarios, one vision is established and uncertainty about the future is handled through sensitivity analyses.

The following elements go into the evaluation:

Changes in socio economic **benefits** for Denmark incurred by the transmission project:

- Trading benefits: Changes in consumer surplus, producer surplus and congestion rents. Calculated by market models.
- System supporting services: Reduced cost of e.g. system supporting grid components
- Transit compensation: compensation from neighboring countries for transits
- Security of supply: Value of project with regard to securing the supply
- Regulating power: Value of increased opportunities for balancing services between market areas
- Other elements: for example subsidy from EU funds

Changes in socio economic **costs** for Denmark:

- Costs due to changes in transmission losses
- Investment: Cost of investment
- Operation and maintenance: Costs of operation and maintenance during the expected lifetime (plus/minus incurred changes in other costs due to the investment)
- Changes of reserves: costs/benefits of increased/reduced reserves
- Costs of non-availability of interconnector: reduced trade benefits

Figure 44 defines and illustrates some important concepts in regard to trading benefits in an example with only two areas. “L” indicates a low price area and “H” a high price area. The interconnection capacity is “C”.

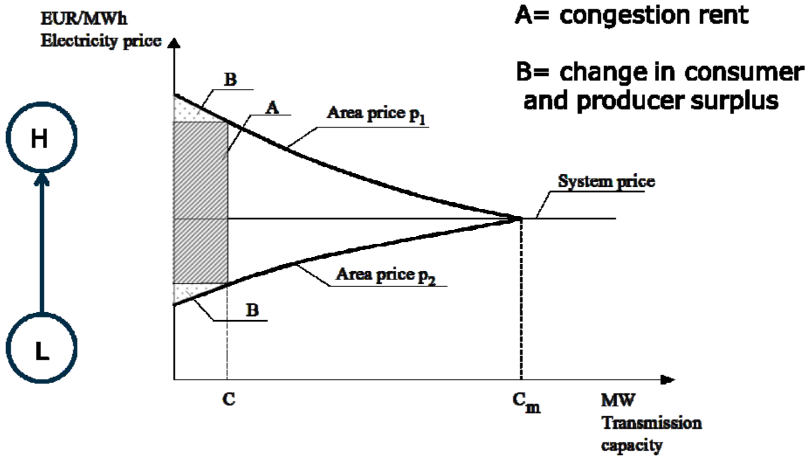


Figure 44: Trading benefits. Congestion rent and total trading benefit

Power transport from L to H involves a decrease of market price in H and increase in L. The congestion rent is represented by A. The two areas B are the net changes in producer and consumer surplus in high price area (upper B) and low price area (lower B), respectively.

Figure 45 shows how the concepts of consumer and producer surplus are defined in the two price zones. The congestion rent is the exchanged power times the price difference between the two areas. The congestion rent is the money in surplus, because the “exporter” in “low price area” is paid a less price than the consumer must pay in “high price area”. The additional net benefits are represented by the two green triangles and the two yellow areas are “redistributions” of benefits between consumers and producers.

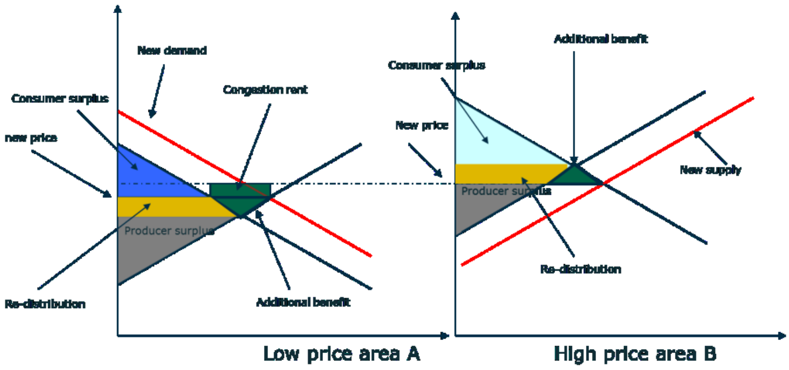


Figure 45: Definition of producer surplus, consumer surplus and congestion rent and changes due exchange of power

Figure 46 illustrates the marginal congestion rent and the marginal trading benefits with increasing interconnector capacity. Also the marginal cost of building the interconnector is shown.

The optimal transmission capacity in the socio economic analysis is the crossing between marginal costs and marginal trading benefits (neglecting other benefits than trading benefits). For a private investor, who only has income from the congestion rent the optimal capacity is less (crossing of marginal congestion rent with marginal cost).

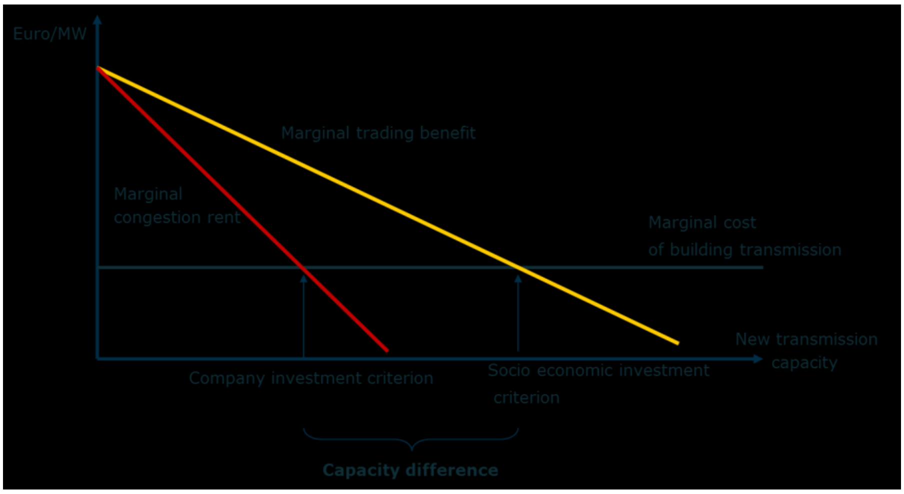


Figure 46: *Criteria for investments*

The figure also provides an argument for why development of the optimal transmission system infrastructure is better handled by public owned TSO’s, compared to private companies, seen from the perspective of the society.

Market modelling

The principles described above are extended to encompass many areas covering Northern Europe. This is done in a market model, which simulates the European day-ahead market hour per hour through the year. Calculations are made for several future years (for example 2020 and 2030). Simulations are made excluding and including the proposed project. The trading benefits are estimated by subtracting the results of the two corresponding simulations.

5.6 Conclusions and lessons learned regarding planning framework for China

The European ENTSO-E approach to developing Ten Year Network Development Plans (TYNDP) is an example of a coherent and integrated framework for integration of larger geographical areas and countries into a common market strucure and centralised transmission system planning platform.

This framework has proven to efficient for integration of renewable energy and should be of interest in a Chinese context.

6. Operation and management of transmission infrastructure

6.1 Utilisation of Danish transmission grid to neighboring countries

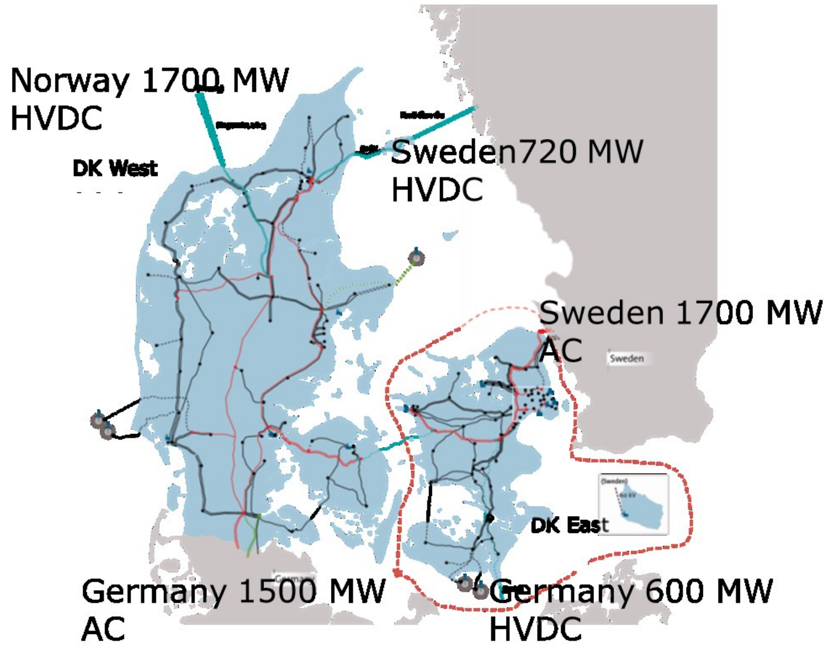


Figure 47: Interconnectors to neighboring countries. HVDC and AC. DK West and DK East are connected by 600 MW HVDC.

The following statistics covers the usage and utilization of the Danish interconnectors to the neighbouring countries. There are large differences from year to year this is mainly explained by the hydro power production in Norway and Sweden. Some years have larger precipitation meaning the hydro power plants can supply more electricity (wet years) and other years there is little precipitation resulting in less available production capacity from the hydro power plants (dry years). During wet years there is typically a large import of power to DK from Norway and Sweden and during dry years there is large export from Denmark.

A part of the import/export to and from Norway is transit power from Germany or further south in Europe. In years with a large export to Norway or Sweden there is also a large import from Germany.

The connection to Norway is used extensively and is a main both for bulk transfer of energy and to balance daily variations in productions and demand. Examples of this can be seen in Figure 49 to Figure 52. In the end of 2014 the connection to Norway was upgraded from 1000 MW to 1700 MW by an addition of 700 MW HVDC.

The connection from DK-W to Sweden was increased from 340 to 720 MW by end of 2010.

The connection between DK-W and Germany, 1500 MW AC, often sees restrictions in capacity due to congestions in the German grid.

All interconnectors, both AC and HVDC, are used very dynamically during each day with hourly ramping and up to daily change of flow direction.

	DK-W Norway			DK-W Sweden			DKW-Germany			DK-E Sweden			DKE-Germany		
	Import	Export	Utilisation	Import	Export	Utilisation	Import	Export	Utilisation	Import	Export	Utilisation	Import	Export	Utilisation
2010	1452	-4049	63%	513	-1595	71%	3593	-1944	42%	2170	-3326	37%	2738	-686	65%
2011	3598	-2411	69%	1654	-833	39%	1598	-3064	35%	3533	-1906	37%	1234	-2083	63%
2012	5455	-673	70%	2884	-734	57%	703	-5287	45%	6202	-837	47%	615	-3112	71%
2013	2553	-2840	62%	927	-1689	41%	3123	-2037	39%	2324	-2573	33%	2497	-1214	71%
2014	4120	-1453	64%	1136	-2113	52%	1880	-2552	34%	3581	-1592	35%	1844	-1995	73%

*Figure 48: Yearly transfered energy [GWh] and utilisation of interconnectors. The utilization is calculated as the ratio between energy transferred and the theoretical max transfer capacity defined as capacity*hours per year.*

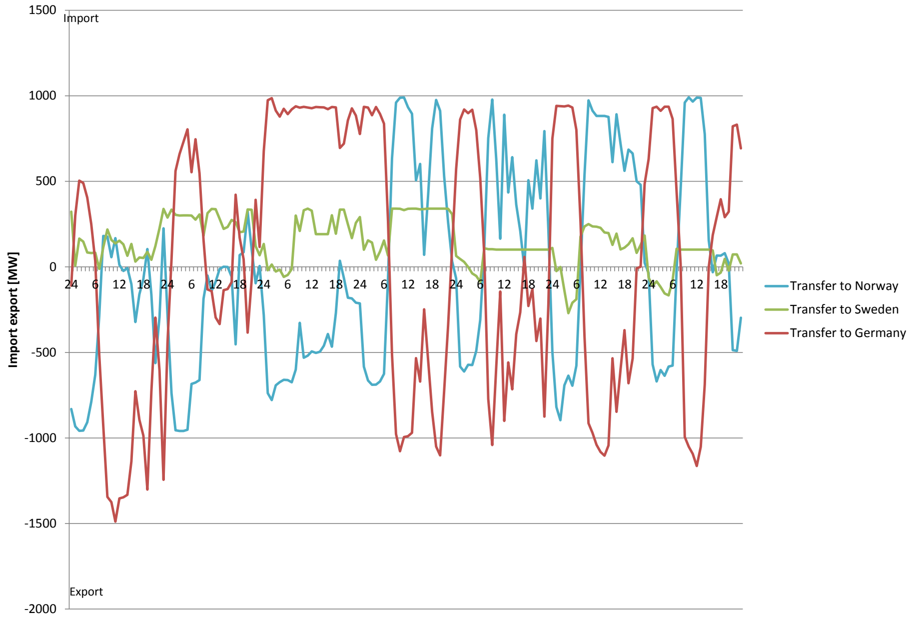


Figure 49: Summer 2010. Daily patterns can be observed with import from Germany and export to Norway. This is an example of Hydro power in Norway is balancing demand in Germany.

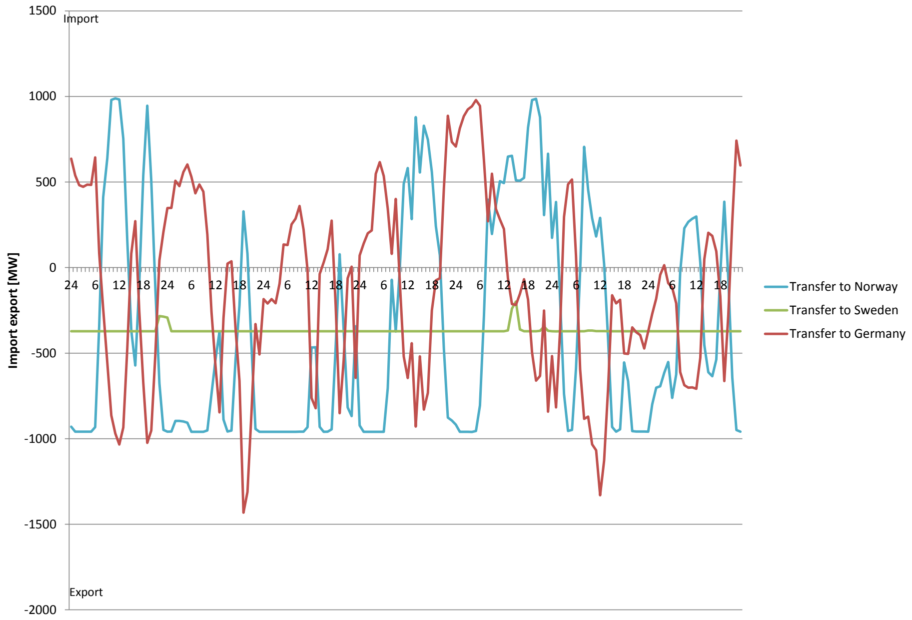


Figure 50: Winter 2010. Similar picture to summer except for very little export to Norway due to dry year conditions. However the interconnection to Norway is still balancing load and production in Germany

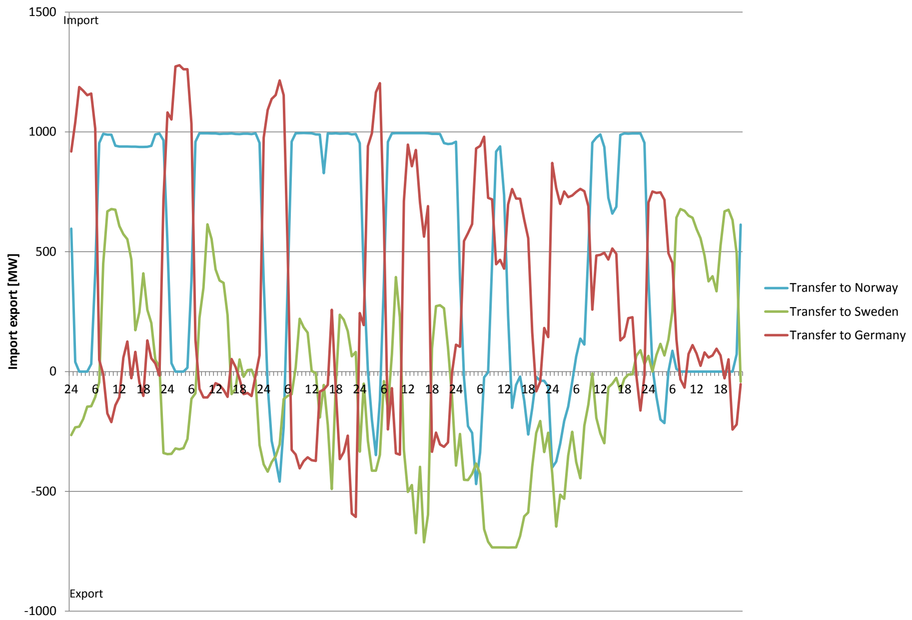


Figure 51 Summer 2014. A new picture compared to 2015. A year with surplus of hydro in the Nordic and a surplus of power from Germany during daytime. Most likely due to solar power. Very little net power production in DK.

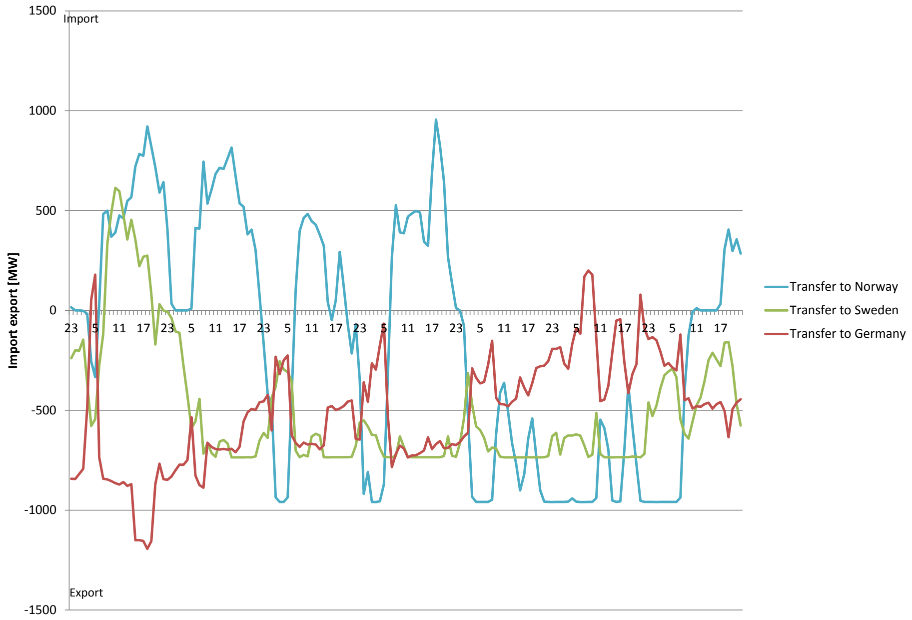


Figure 52: Winter 2014. Similar picture to winter 2010 but a growing tendency to net positive export from Denmark. Winter is high season for wind power and CHP which can result in oversupply of electricity. This is mainly absorbed in the neighboring countries.

6.2 Case study of energy exchange on specific interconnector

Figure 53 shows Denmark as a link between the hydro-based Norway (~ 95 % hydro generation) and Sweden (hydro, nuclear and fossil) and the thermal European continental power system.

As case study on exchanges on interconnectors we will show examples for the DK-NO cross border transmission line with a nominal capacity of 1 700 MW (4 DC connections). The last DC connection (700 MW) was commissioned in the spring 2015.

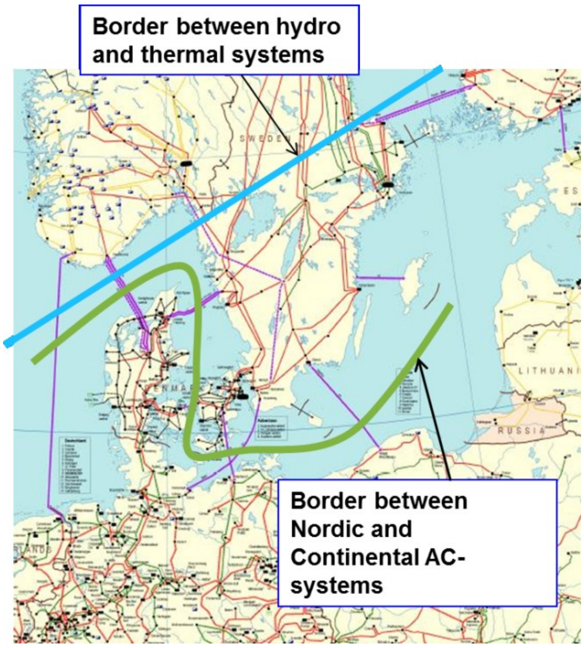


Figure 53: Denmark as a bridge between Scandinavia and the Continental Europe

The upper part of Figure 54 was presented in section 4.5.1, where market prices were described. It shows the dynamics of hourly spot prices in Denmark (DK West) during a week in January 2014. The main driver for volatility is the high variation in wind power, indicated by the green band. In the start of the week (Tuesday) the wind power generation is very limited, import (positive values in Figure 54) is necessary and the price moves up till 70 EUR/MWh. In the weekend the wind power dominates the supply profile, export (negative values in Figure 54) is prevailing and prices drop to 0 EUR/MWh.

The lower part of the figure shows the exchange on the interconnector to Norway in the same week. Also zonal prices in Norway and Denmark are shown. The load on the interconnector is optimized in the price-coupled day-ahead market (see section 4.2.1).

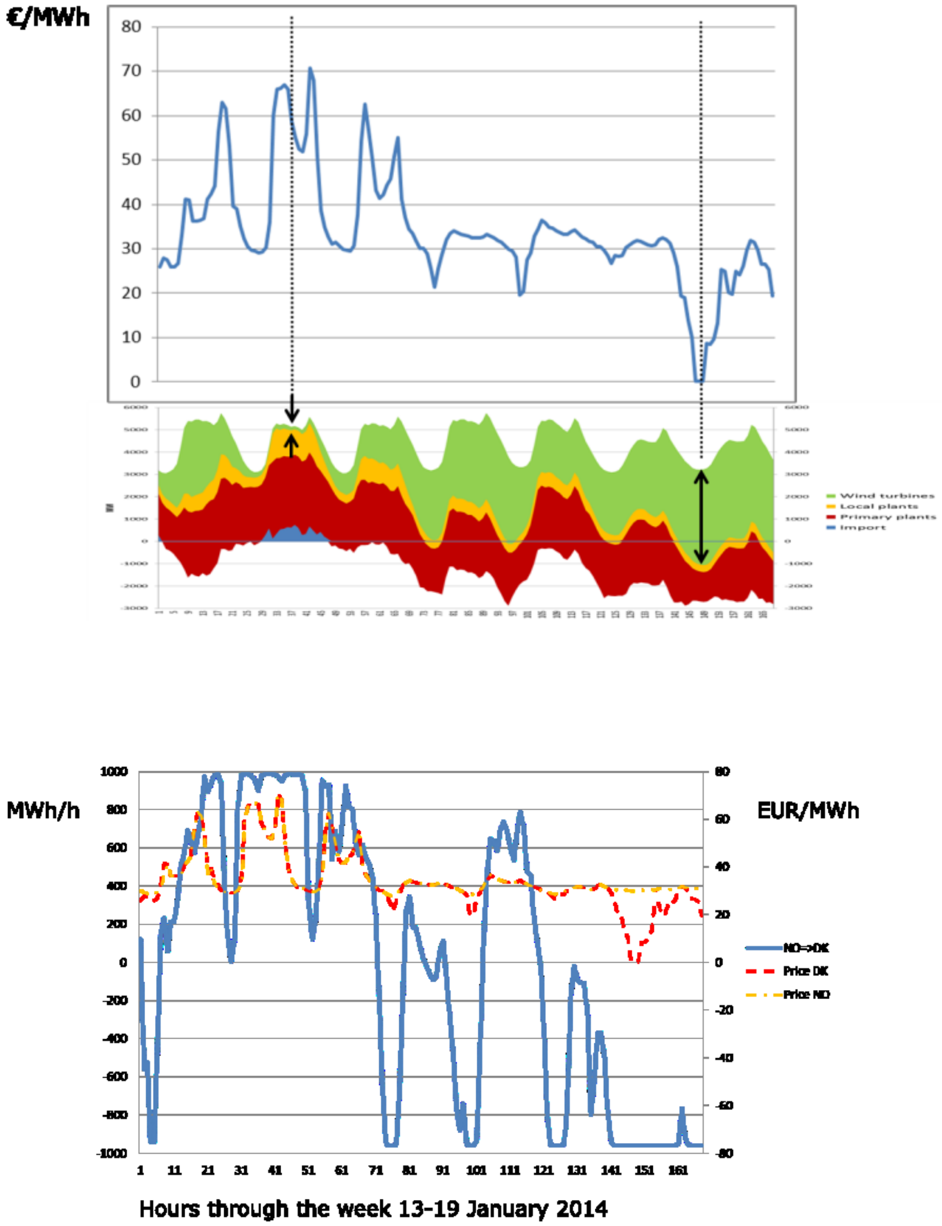


Figure 54: Price volatility due to variations in wind power generation. Interconnector capacity to e.g. Norway (capacity ~1,000 MW in 2014) is intensively used in the market balancing process. (Import to Denmark has positive value).

It follows that the optimal market solution prescribes a high variation in exchange during the week. Also during the day the interconnector load varies with import (positive values in Figure 54) to Denmark (DK West) in some peak hours during the day and export during night hours. In addition it should be noticed that when a price difference between Denmark and Norway occurs, the interconnector is fully loaded (congestion).

In addition fig. 4.3 shows the exchange over the week 13-19 April 2015, now with a nominal capacity of 1,700 MW on the interconnector from Denmark (West) to Norway. However the import/export capacities are reduced due to grid constraints in the Norwegian system. The capacities (NTC values) being available for the market are shown as dotted lines (about -1,500 MW as export and 800-1,500 MW as import capacity in the actual week).

It follows that the exchange and the Danish (DK West) net-consumption (consumption minus intermittent production from wind and solar PV) are highly correlated: import during (high) positive net-consumption, export during (high) negative net-consumption. The surplus of intermittent RES generation in Denmark is exported to the hydro-based Norway (and stored in Norwegian hydro reservoirs) and so to speak “imported back” during hours with positive net consumption.

Figure 55 also shows that the price is very stable in Norway because of the large hydro reservoirs. The price in Denmark varies although stabilised by the Norwegian price. When a price difference occurs, the interconnector is congested.

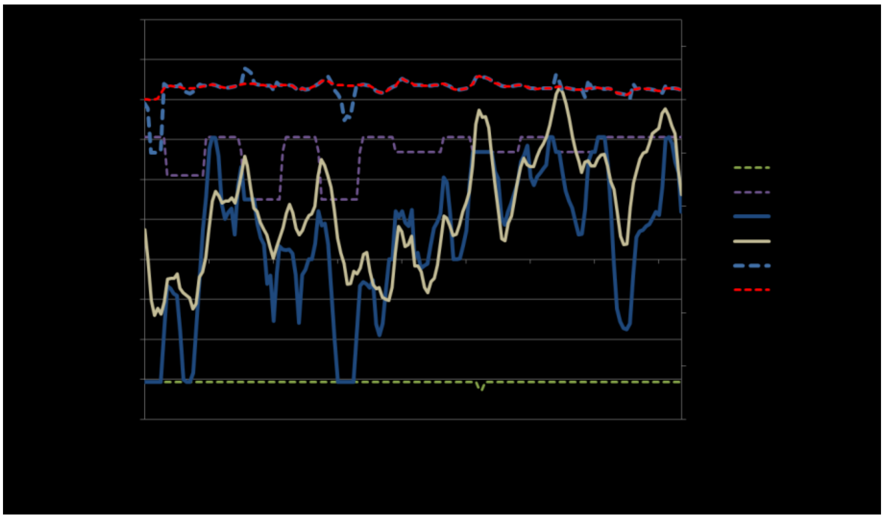


Figure 55: Market prices; net consumption and exchange with Norway

6.3 Planning and tendering of transmission lines and interconnectors in Denmark

Each second year Energinet.dk issues a national grid development plan. The last one is dated 2013.

The plan includes:

- The long term transmission grid structure for 2032 and the development through the intermediate steps in 2017 and 2022
- An optimized schedule for dismantling existing 132/150 kV transmission OH-lines and instead building underground 132/150 kV transmission cables
- Cost estimates for carrying through the plan

The National Grid Plan has its focus on domestic projects. New interconnectors that cross borders are planned within the European ENTSO-E framework and become part of the TYNDP and Regional Investment Plans, see sections 5.1 to 5.5.

After the planning phase and a succeeding pre-feasibility study, the project design phase can start. For interconnectors the projects are carried out in a joint cooperation with the neighbor TSO at the other end of the line.

The project ends up with a description of technical specifications, a financial analysus, the budget and a cost-benefit analysis, as previously described.

For each transmission project a convincing business case must be approved by Energinet.dk's Board of Directors and for larger projects in addition by Energinet.dk's Supervisory Board. For larger projects the case is forwarded for approval by the Energy Authorities and the Minister.

Finally the detailed design is carried out by Energinet.dk together with possible partner-TSO. In parallel the public hearings described in the law and meetings with involved stakeholders are taking place. Modifications and changes to the project are incorporated.

The final detailed project documents form basis for an international call for tender following the EU rules. The best bid is chosen and the construction work can start.

The Danish costs of new transmission lines are socialized over the transmission tariff paid by all Danish consumers according to their energy consumption.

6.4 Planning and tendering of off-shore wind farms in Denmark

Figure 56 shows the latest commissioned (September 2013) offshore wind farm in Denmark. It has a capacity of 400 MW (111 turbines, each 3.6 MW) and is located about 20 km from shore. The wind farm is connected as AC. The upper part of the figure shows the offshore connection platform and the wind turbines.

The TSO plans and gets approval for the connection of the offshore park along the same procedure as for transmission lines described above. The TSO can afterwards build the connection, in this case consisting of an offshore platform incl. transformers, 24 km 245 kV sea cable, a reactor at the shoreline and 55 km of 245 kV underground cable. Then follows another compensating reactor before connection to an existing land based substation. Total cost for connection was €165 mill. The investment is socialized over the PSO tariff (public service obligation) paid by all Danish consumers according to their consumption.

The locations of the offshore wind farms are suggested by the Danish Energy Agency. The selection is done after a comprehensive planning process and according to a number of criteria, among others:

- Technical-economic, e.g. electrical connection to grid, geotechnical conditions of the seabed, distance to shore, nearby ports
- Criteria of other land use interests: fishery, mineral resources etc.
- Recreational values
- Visual impacts

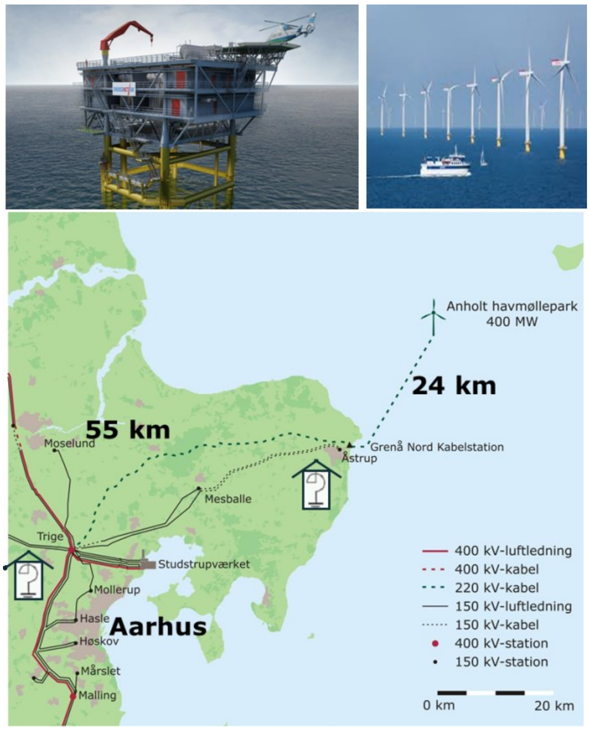


Figure 56: Connection of Anholt 400 MW offshore wind farm

After political endorsement by the Government the Energy Agency calls for tender for the delivery and construction of wind turbines including connection to the offshore platform. The winner of the tender is the bidder giving the lowest price (EUR/MWh of generation) for building and operating the wind farm.

The price in the Anholt case was 140 EUR/MWh, which the owner is paid for the first 50,000 full load hours (corresponding to about 12 years generation). After that there is no subsidy and the generation is paid the market price. The subsidy is socialized over the PSO (public service obligation) tariff paid by all Danish consumers according to their consumption. No subsidy is paid when the market price is negative.

The next offshore wind farm to be built in Denmark has a capacity of 400 MW (Hors Rev 3). The winning bid for this project was 102 EUR/MWh (for the first 50,000 full load hours). The wind farm will be ready for operation at the end of 2019.

6.5 Conclusions and lessons learned for China

The following observations should be noticed:

- In a price coupled market the exchange on interconnectors may change on hourly basis depending on specific system characteristics. Intermittent RES generation may be a driver for changing of exchange patterns
- The load on interconnectors are optimized in the market scheduling process
- Decision on transmission development is taken on basis of socio economic cost benefit analyses. Investment costs are paid for over the transmission tariff
- Denmark uses a competitive tendering process for establishing of offshore wind power farms. Cheapest bid is selected. Investment costs are socialized over the PSO (public service obligation) tariff

7. Power Exchanges in Europe

7.1 Role of the market

Over the last decade and in the face of the ongoing liberalization of the electricity sector in Europe as for many other parts of the world, a number of power exchanges have been put into operation. The main goal has been to create an exchange-based spot markets facilitating trading of short-term standardized products and the promotion of market information, competition, and liquidity. Power exchanges also provide other benefits, such as a neutral marketplace, a neutral price reference, easy access, low transaction costs, a safe counterpart, and clearing and settlement service. Besides, spot market prices are an important reference both for over-the-counter (bilateral) trading, and for the trading of forward, future and option contracts.

In a European context the creation of power pools has mainly been a result of a regional process both within the different European countries but also in some cases between smaller neighboring countries like we have witness among the small Nordic countries with the creation of Nordel and later Nord Pool. With the creation of the European Union and the “common market” in Europe the ambition of a common European power pool and electricity market was a natural next step. With the European Union's *third package* of energy market legislation the foundation for improvements of functions of the internal energy market has been made. The European Commission has a stated goal of harmonizing the European power markets. The aim is to create a pan-European market with closer connecting of power markets to improve the efficient use of energy across national borders, the *European Target Model* for electricity market integration. The current legal foundation of this common European electricity market was established in 2009 and can be found in *Directive 2009/72/EC* concerning common rules for the internal market in electricity.

Significant milestones were reached last year on electricity market coupling thanks to the common work of various Transmission System Operators. First of all the full price coupling of the South-Western Europe (SWE) and North-Western Europe (NWE) day-ahead power markets was achieved in May 2014, thus creating the largest day-ahead energy market ever, as electricity can now be exchanged from Portugal to Finland or from Germany to the United Kingdom. Similar progress was made in Eastern Europe, where national regulators and TSO’s have committed to an ambitious timetable for market coupling of that part of the EU power market.

7.2 Organization, services and products

Despite the trend toward a common power pool in most of Europe the market is still split among some of the original power pool and power exchanges with the following as the most important in alphabetical order:

- APX (Holland)
- Borzen (Slovenia)
- EEX (Germany)
- EXAA (Austria)
- GME (Italy)
- Nord Pool (Denmark, Finland, Norway and Sweden)
- OMEL (Spain)
- Powernext (France)
- UKPX / APX UK /UK IPE (United Kingdom)

It is important to emphasize that the volume traded in the different exchanges is not proportional to the size of the different markets as some the markets most of the power trade is made outside of the market as it is the case of the UK power exchanges. For other exchanges almost all power is traded on the exchange as it is the case for OMEL and Nord Pool.

The different power exchanges offer a number product and services with the focus of a day-ahead spot market as the core platform. In the day-ahead market blocks of time bound electricity generation like 1 MWh on an hourly basis is traded one day ahead of delivery and the price is normally fixed through an auction. For some power exchanges the time blocks can be shorter than an hour (half an hour, 15 minutes or even 5 minutes blocks).

Many of the power exchanges also have a market for balancing power or adjustment power market. In this market the system operator can buy balancing capacity to fine tune demand and supply due to unexpected events.

Going forward it seems that the German power exchange EEX is going to be the future common European power exchange. But as the physical constrains of grid capacity will be a fact of life even with the current European grid expansion plans the local power exchanges is not likely to disappear any time soon.

7.3 Financial products and forward markets

Apart from a physical electricity market some of the current power exchanges are also offering financial products that like in the financial markets (bonds, stock and currencies) can be used by various market participants to hedge future power price volatility. These “financial contracts” can be different form of derivatives like forward contracts. A large power consumer can through such a financial forward contract fix his future energy price for a given period of time into the future through a hedging strategy. This is done by combining a physical contract when buying a certain amount of electricity by a financial selling contract ahead of the trade. Other more exotic financial contracts like future and option contract is also an option in some power exchanges.

The ability to create a liquid financial market for power market related product is of cause enhanced by the underlying volume and liquidity of the physical power market. This will further stimulate a concentration of the power trading to fewer power exchanges. Again the limitation for the physical power market will continue to be an obstacle for a total unification of the power market trading and the ability to further develop financial products for relative illiquid markets.