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Contents

1. Summary conclusions and recommendations

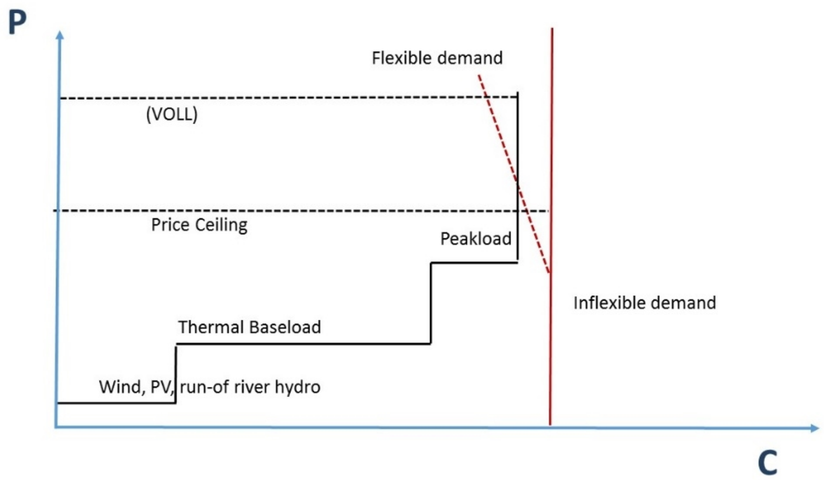
The scope of this report is threefold:

- to describe and analyse proposals on capacity remuneration mechanisms in selected countries including their impact on the Nordic electricity market
- to evaluate whether major incompatibility issues exist between relevant communications from the EU Commission and the current Nordic market model
- to evaluate if the Nordic market is in need for or suited for capacity mechanisms in order to secure the balance between supply and demand.

1.1 Background

It is a fundamental assumption behind the liberalization of the Nordic electricity markets that market forces in a well-functioning Energy Only Market (EOM) will efficiently provide the necessary adequacy to balance supply and demand. However, one well-known challenge of electricity markets is low demand flexibility. Low demand flexibility contributes to the risk of involuntary load shedding and to the inability of the market to determine the market-clearing prices needed to attract an efficient level and mix of generation capacity. Moreover, the problems caused by this “market failure” can result in considerable price volatility and market power (Peter Cramton, Axel Ockenfels, and Steven Stoft, 2013).

Figure 1: Price formation in an electricity market in hours of scarcity



Note: If demand flexibility is non-existent (or low), the supply and demand curves may not meet and it can be necessary to shed load (brownout).

In literature, the lack of flexible demand is considered a market failure so serious that it inevitably, in theory, leads to load shedding unless some kind of a capacity mechanism is implemented.

The reason is that the last supply resort, the capacity unit with the highest marginal costs such as gas turbines, have annual fixed costs that energy sales need to cover. However, if the marginal cost of the last resort itself sets the price in times of scarcity, there will never be remuneration for fixed costs, and the plant will eventually close.

In addition to the market failure of low demand flexibility, three other challenges for the EOM to deliver the necessary adequacy should be mentioned:

- The growth of subsidised renewable energy yields less "residual demand" for the thermal power plants to serve, thus lowering the market prices until more thermal capacity has been decommissioned.
- Although the market has worked since the birth of Nord Pool in 1996, the number of incidents with price spikes is very small. Investors do not yet have substantiated projections about the market function in recurring times of scarcity. How will decision makers react if/when the price ceiling is reached for many hours every second year?

- The price ceiling is currently 3,000 EUR/MWh in the spot market, and higher in the balancing market. If this price is below the relevant VOLL, the market may not be able to find its long-term balance.

Such challenges have led several countries to discuss and implement different capacity mechanisms. Although these mechanisms are mainly national by design they potentially impact the price formation in adjacent markets significantly, which in turn threatens the structure in these markets and eventually the vision of the Internal Electricity Market (IEM).

1.2 EU framework

1.2.1 Rules on state aid

In 2014, the Commission published Guidelines on State aid for environmental protection and energy (EEAG) including Aid for generation adequacy.

Some of the key points are that: a) the identification of a generation adequacy problem shall be consistent with the generation adequacy analysis carried out regularly by ENTSO-E; b) the assessment shall include the impact of variable generation, the impact of demand-side participation and the impact of interconnectors; c) the mechanism shall incentivise both supply- and demand side; and d) avoid undue negative effects on competition and trade.

1.2.2 Sector inquiry

In April 2015, the Commission launched a state aid sector inquiry into capacity mechanisms. In order to better understand the capacity mechanisms already implemented or under consideration. Eleven Member States were initially selected including Denmark and Sweden. The UK was not included since the Commission approved the UK's capacity mechanism already in July 2014.

At the launch, the Commission expected to publish a draft report for consultation around the end of 2015, and a final report in summer 2016.

1.2.3 DG Competition working group with Member States

The commission presented a draft paper comparing capacity mechanism models and their compatibility with State aid Guidelines in June 2015. The paper groups six various forms of capacity mechanisms into two broad categories; targeted mechanisms and market-wide mechanisms. In this context, strategic reserves are categorised as a targeted volume-based mechanism.

DG Comp also presented a draft paper regarding participation of interconnectors and/or foreign capacity providers in capacity mechanisms. The importance of enabling cross-border participation is emphasized, but also the risk of undermining the market coupling rules and distortion of the merit order in neighbouring markets is mentioned.

Based on a short discussion about the pros and cons of procuring strategic reserves in a neighbouring bidding zone, the paper questions whether cross border participation can be enabled effectively for other models than volume-based market-wide designs.

1.2.4 Consultation on Summer package

As part of the Energy Union strategy, a public consultation on a new energy market design was launched in July 2015 by the Commission.[1] In conclusions from a session in the Florence Forum[2] on 9 October it was noted that capacity remuneration mechanism might be warranted under certain circumstances, notably when they are linked to a regional assessment and do not undermine price signals. Also, the need for a common definition of reliability standards, framework for cross-border and demand side participation and governance issues were mentioned.

1.2.5 Our evaluation

The EU framework is under development and definitive conclusions regarding compliance from our side is not possible at this point in time. However, we believe that the six points listed below are important evaluation criteria:

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[1] Closed on 8 October.

[2] The Electricity Regulatory Forum (Florence Forum) was set up to discuss the creation of the internal electricity market. Participants include national regulatory authorities, Member State governments, the European Commission, TSOs, electricity traders, consumers, network users, and power exchanges. Since 1998 the Forum has meet once or twice a year.

- The objective and the need for a capacity mechanism shall be assessed on a regional basis instead of a national basis.
- Common European methodology for generation adequacy assessment (including possible imports and demand flexibility in scarcity situations) is needed.
- Framework for demand-side participation.
- Framework for cross-border participation.
- The mechanism must not undermine price signals
- Governance issues.

DG Competition seems so far to be more positive towards market-wide mechanisms due to the thinking that more participation yields more competition. Others see a of risk undermining the fundamental energy market in such a development[3] and have therefore preferred a targeted mechanism as a strategic reserve since it can better be combined with an energy-only market. We do not expect that the Commission will make a clear choice this year. We expect therefore that both market-wide mechanisms and targeted mechanisms will be possible.

[3] An in-depth analysis of these risks was e.g. presented 2015 by the German Federal Ministry for Economic Affairs and Energy (BMWi) in its white-paper An Electricity Market for Germany's Energy Transition.

1.3 Capacity mechanisms in selected European countries

In accordance with the tender, the capacity mechanisms in France, Germany, Italy and the UK are described in this report.

1.3.1 Brief capacity mechanisms overview

Table 1: Capacity market overview

Features	UK	Germany	France	Italy
Core features				
Targeted or market wide	Market-wide	Targeted	Market-wide	Market-wide
Volume or price based	Volume	Volume	Volume	Volume
Central or decentral	Central	Central	Decentral	Central
Reliability standard	LoLE = 3h/y	None	LoLE = 3h/y	None
Is it technology neutral	Yes	No	Yes	No
Physical/financial obligation	Physical	Physical	Physical	Both
Rules for activation	TSO call	TSO call Activated as a last resort.	TSO call.	Not relevant
Expected price effect: Day-ahead market	Negative	A small increase	Negative	Negative
Financing principle	Cost causality	Cost causality	Cost causality	Pro rata energy fee

Note: Further details can be found in Chapter 3.

1.3.2 United Kingdom

The UK[4] has opted for a central capacity market in which a target capacity level is procured through auctions by the system operator (National Grid). Successful auction participants commit to the delivery of electricity (or demand reduction) – the capacity obligation – when called upon by National Grid in times of system stress during the contract period. Failure to comply with the obligation entails penalties. In return, successful participants receive an annual payment corresponding to the auction clearing price.

[4] Even though the capacity mechanism in the UK excludes Northern Ireland, the mechanism is referred to as a UK mechanism in this report.

The capacity market consists of two annual auctions: the T-4 auction 4 years ahead of delivery and the T-1 auction 1 year ahead of delivery. The first T-4 auction was held in 2014 and the second T-4 auction was held in 2015, with deliveries in 2018 and 2019 respectively. Clearing prices were GBP 19,400/MW/year for the first auction and GBP 18,000/MW/year for the second auction. Substantially lower than expected by the government. In both finalized auctions, the majority of contracted capacity consists of existing and prospective refurbished capacities. New capacities only make up a minor share of roughly 5 percent.

The demand for capacity is set by the government based on recommendations from National Grid. All capacity types are eligible for participation if they do not already receive other support measures.

The mechanism is financed through a charge on all licensed suppliers based on their demand between 4–7 pm on winter weekdays.

1.3.3 Germany

The Federal Ministry for Economic Affairs and Energy (BMWi) released a Green Paper in 2014 pointing out two different approaches to ensuring a secure electricity supply. The first approach involved an energy-only market entitled “Electricity Market 2.0”, in which barriers to the delivery of correct price signals are removed. The second approach involved the creation of a capacity market in addition to the energy-only market. After consultations with stakeholders it was decided to move forward with the first approach. As an additional safeguard, this reformed electricity market contains a capacity reserve that will only be activated as a last resort.

Three important arguments for the “Electricity Market 2.0” were:

- A reformed electricity market can deliver a secure electricity supply. In the longer term. The integration of electricity markets across Europe implies large-scale smoothing effects with respect to both peak loads and production from renewables, reducing the need for capacity. In addition, it was argued that capacity is already remunerated both implicitly and explicitly.
- The “Electricity Market 2.0” is cheaper than opting for a capacity market due to the complexity and regulating costs of such markets. In addition, it is argued that an undistorted price signal in the market is the most cost-efficient way of integrating renewables.
- Innovation and sustainability is cost-efficiently promoted through by leaving the price signal undistorted. In contrast, the introduction of new flexibility options in a regulated market is difficult, as the regulator will

have to define the terms and conditions of trading and pricing which could distort the competition in favor of existing technologies.

The capacity reserve will consist of power plants that are not active on the electricity market, and which are likely to be commercially inoperable. The reserve is expected to amount to roughly 5 percent of the anticipated average annual peak load, and will be procured through competitive tenders.

The reserve will work as a last resort and only be activated if the day-ahead market, the intraday market, and the balancing capacity reserves of the system operator prove insufficient to meet demand. Activation of the reserve will happen at a minimum price of EUR 20,000 per MWh – twice the maximum technical price in the intra-day market. Billing will take place through the established balancing capacity system.

If the reserve is not activated, the reserve-costs will be shared amongst all electricity consumers. If the reserve is activated, a percentage of the reserve-costs – reflecting the contribution to the need to activate the reserve – will be allocated to electricity suppliers who failed to meet their supply obligation.

The White Paper also proposes a so-called grid reserve. The capacity reserve is a German-wide instrument whereas the grid reserve is a regional instrument, which expires when planned grid investments are completed.

1.3.4 France

The French capacity market obliges electricity suppliers to hold capacity certificates corresponding to their contribution to the risk of a capacity shortfall as if every year faced a 10-year winter. If electricity suppliers fail to meet their obligation, penalties are imposed. The first delivery year is 2017.

There are different certification procedures for controllable and intermittent generation capacities. Participation in the certification procedure is mandatory for all capacities connected to public grids.

Obligated parties can meet their obligation in various ways, such as holding capacity certificates acquired through bilateral trading or a central exchange platform.

1.3.5 Italy

The Italian capacity mechanism consists of a centralized capacity market in which reliability options are auctioned off to eligible auction participants. The capacity market product – the reliability option – is a contract-for-difference. This contract contains a capacity payment to successful auction participants, which in turn agree to two conditions. Firstly, the contracted capacity must bid into either the day-ahead market or the ancillary services market. Secondly, operators of contracted capacity agree to pay back the difference between a contractually foreseen spot-market price and a pre-defined contractual "strike-price", whenever this difference is positive. The "strike-price" represents the variable costs of the marginal technology, i.e. an efficient peak plant.

The demand in the market is determined annually on a regional basis by the TSO (Terna).

The supply in the market is determined by operators of generation and demand side capacities. Auction participation is voluntary. Both new and existing capacities are eligible to participate except intermittent generation and capacities subject to incentive schemes. Plans to include both demand response and interconnector capacities exist.

The main auction is held four years prior to delivery, with a delivery period of three years. The capacity payment is determined by the clearing price of the auction, as long as this price falls within a certain range defined by a price floor (fixed costs of a CCGT plant) and a price cap (calculated cost of new entrant).

As we understand it, the costs of the capacity mechanism are smoothed on all consumers through a pro rate energy fee.

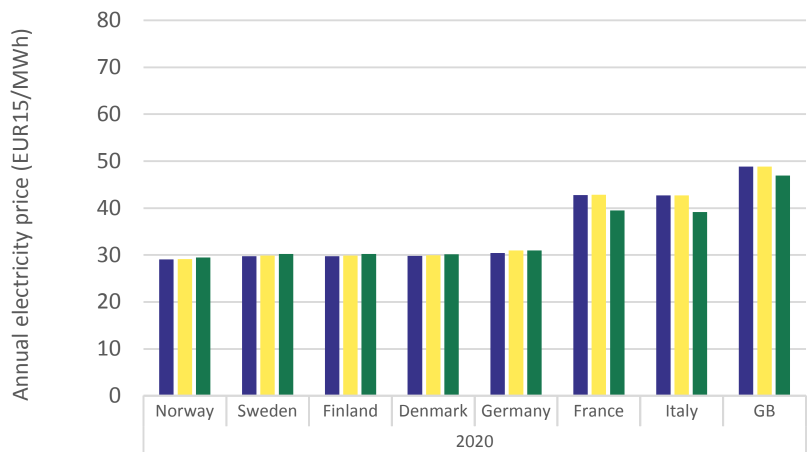
1.4 Impact to the Nordic region of described mechanisms

By using the electricity market model Balmorel the impact on the Nordic region of the described capacity mechanisms in UK and the continent have been analysed. The main purpose of the analysis is to evaluate how these markets affect commercial decisions regarding new investments and decommissioning of existing plants. The model is based on a relatively detailed technical representation of the existing power system in the relevant countries. It can make investments in new capacity based on a catalogue of technologies, and decommission plants if their annual earnings do not cover fixed costs. The optimization takes into account fuel costs, transmission costs, fuel and emission taxes, operation and maintenance costs etc.

The model will always secure just enough commercial capacity to balance the market in peak condition. However, the model will not allow prices to exceed the price cap. If higher prices are necessary in order attract marginal peak-load investment (or in order to keep older plants in the market), the model will perform load-shedding.

The results cannot by themselves be interpreted as a proof that the EOM will work in the short term (towards 2020). In the world of the model, the necessary investments will inevitably take place as soon as the pre-defined return on capital is achievable in a “normal year”. The main purpose of the modelling is therefore to evaluate the impact of capacity mechanisms in adjacent countries.

Figure 2: Average annual electricity price (EUR15/MWh) for the year 2020. Reference scenario: EOM in all countries. SR_Germany: Strategic reserve in Germany, EOM in other countries. CM: Capacity mechanisms as described in UK, Germany, France and Italy. EOM in other countries



	Norway	Sweden	Finland	Denmark	Germany	France	Italy	GB
Reference	29,0	29,8	29,8	29,8	30,4	42,8	42,7	48,9
SR_Germany	29,2	29,9	29,9	29,9	31,0	42,8	42,7	48,9
CM	29,5	30,3	30,2	30,2	31,0	39,5	39,2	46,9

It appears from Figure 2 that the implementation of a capacity market in a country can have a substantial effect on prices in that country. However, the modelling also shows that the effects on prices and capacity balances in the Nordic countries are likely to be low. As expected the strategic reserve in Germany will increase prices slightly, whereas the capacity markets in the three other countries have the opposite effect. The net result seems to be insignificant for the Nordic region and the individual Nordic countries.

1.4.1 Fluctuating renewables

Peak power plants need scarcity pricing in the EOM market in order to cover their fixed costs. With the assumption that fixed costs of new entrants is EUR 50,000 per MW/annum a peaking plant needs app. 17 hours/year where the market reaches the price ceiling of 3,000 EUR/MWh.

If there was no wind in the Nordic system, this would require roughly 1,500 MW of demand response when the market is in long term balance (Based on 2015 demand curve). With the current penetration of wind (9% in 2015), the needed demand response grows to roughly 2,200 MW.

Table 2: Calculated theoretical levels of demand response required in the Nordic system to avoid involuntary disconnection (brownout) of consumers

	Demand response is active at	Required demand response, MW (in% of peak demand)	Required demand response, MWh in%	Required demand response, hours per annum
9% wind power as in 2015	EUR 3,000 per MWh	2,200 (3.5%)	0.004	0.3
	EUR 300 per MWh	8,300 (13.0%)	0.2	20
No wind power in the system	EUR 3,000 per MWh	1,500 (2.3%)	0.002	0.2
	EUR 300 per MWh	5,200 (8.2%)	0.1	11

The above needed demand response can be compared to the estimated total potential of 12,000 MW mentioned in Thema (2014). Some of this potential is probably already active in the market.

1.5 Adequacy in Nordic countries

A number of studies have been presented recently in the Nordic countries regarding capacity adequacy and/or challenges for the electricity system because of the ongoing integration of intermittent renewable production. A general conclusion from these studies is that significant decommissioning of existing thermal capacity is expected. This drop in thermal capacity is well in line with the modelling of the market carried out in this study.[5]

In addition, the Nordic TSOs present a common forecast of the power balance for a cold winter day in a 1-in-10 years winters. The forecast for Nordic peak demand in 2015–2016 is estimated at 71,250 MW, 2% lower than the sum of the national peaks. The expected available capacity for the market is 70,300 MW, implying a deficit of 950 MW. The deficit is expected

[5] The model reduces thermal capacity with 7500 MW in total in the Nordic countries in order to find a commercially viable capacity balance in 2020.

to be supplied with imports. The areas with the weakest power balances are Finland, South Sweden (SE3 and SE4) and Eastern Denmark (DK2).

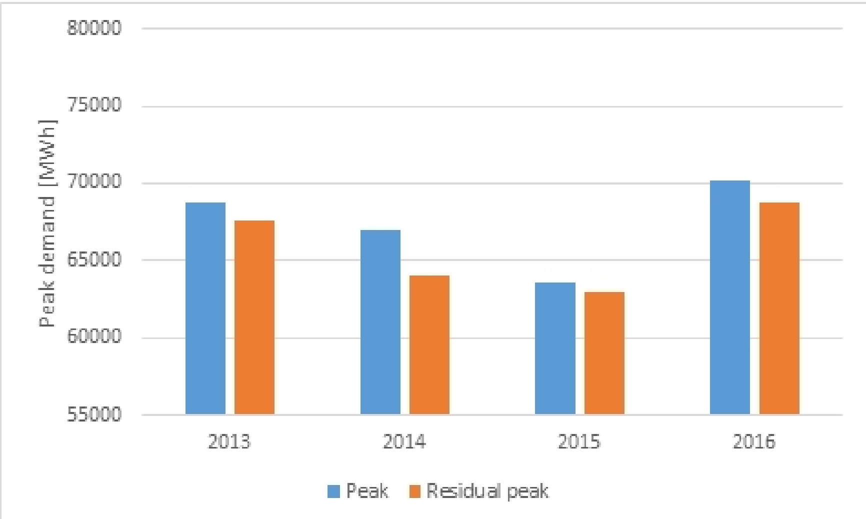
Conclusions based on recent modelling work by Thema (Capacity adequacy in the Nordic electricity market, 2015) is that there is little evidence of severe capacity adequacy challenges in the Nord Pool market area towards 2030.

However, it can be argued that this and other recent studies have not fully included the risk that several existing condensing plants and some gas fired CHP plants will be closed. In addition, recent information show that at most six nuclear reactors will be operational in Sweden after 2020. Such plant closure will also affect the import possibilities in adjacent bidding zones.

1.5.1 Peak and residual peak

One consequence of the increase of fluctuating renewables in the electricity market is that the capacity of thermal plants must decrease according to market logics. This is clearly illustrated when looking at the Nordic peak demand and the Nordic residual peak demand for the last four years.

Figure 3: Common Nordic peak demand and residual peak demand in 2013–2016



Note: Residual peak is defined as the maximum of residual demand (demand minus wind).

The Nordic countries as a region experienced an all-time peak in demand the 21st of January 2016, and the figure shows that the residual peak was somewhat lower. The highest hourly day-ahead price was 214 EUR/MWh. It occurred during the hour with the all-time peak and it was a common price for DK2, FIN, NO1, NO3, NO4 and SE1–SE4. Such a price certainly does not contribute substantially to covering the fixed costs of peaking plants – or baseload plants for that matter.

1.6 Conclusions and recommendations

The point of departure for this project has been to understand the capacity mechanisms in adjacent countries, to evaluate their impact on the Nordic Region and countries and their compliance with communications from the EU Commission and finally to evaluate if the Nordic region is in need of capacity mechanisms.

1.6.1 The challenge and the pros and cons

In theory, the market forces in a well-functioning electricity market will secure the long-term balance between demand and supply. A well-functioning electricity market sends a clear price signal between consumers and producers, and delivers transparent and stable frameworks for investments. Such issues are comprehensively debated in the literature and at conferences.

Apart from clear price signals and stable frameworks for investments, one of the main prerequisites for a well-functioning market is the activation of demand response. Several analyses indicate that demand is already today price responsive, and grid operators in Norway and other countries promote flexible demand by offering lower tariffs for dis-connectible demand. However, it can be questioned whether the current amount is sufficient, and whether it is adequately located according to bottlenecks in the grid.

In addition to this, the market is not currently in a long-term balance. For several reasons, electricity prices are lower than needed in order to sustain existing thermal capacity and foster investments in new capacity. An important reason lies in the increase in (subsidised) renewable production, and probably also in expectations among plant owners that prices will increase again, for which reason they are postponing decommissioning of existing capacities.

In the next 5–10 years, a substantial amount of capacity is expected to close, according to communication from plant owners and according to the modelling of the electricity market. Such closures could be a concern for those authorities that are responsible for security of supply and long-term adequacy.

In other words, it seems justified that different capacity mechanisms are debated among the Nordic countries in these years.

1.6.2 Price ceiling

The price ceiling in the spot market reduces the traders' risk. Too low price ceilings in electricity markets is in some literature mentioned as a market failure. However, even if the current price ceiling in the Nordic market might be below VOLL, it certainly seems high enough to promote substantial flexibility in demand. Yet, if or when the price ceiling will be reached frequently in the future, it could be a signal for a deeper analysis of the rationale behind the current price ceiling.

1.6.3 Strategic reserves

Originally, the Nordic Countries have chosen a path with trust in the basic energy price signal in the electricity market. In addition to the market clearings, the TSO's procure reserves necessary for secure operation.

In Finland and Sweden, the Energy Only market has been complemented with strategic reserves. Also, Denmark has now opted for strategic reserves in Eastern Denmark.

1.6.4 Pro

One pro of a well-designed strategic reserve is that it solves the anticipated adequacy problem without distorting the price signals in the day ahead and intra-day markets. This element is paramount according to communications from the EU commission. Another important pro in the Nordic context is that strategic reserves can be seen as a continuation and only a slight altering of the existing market framework. This signals stability to the stakeholders. Finally, the strategic reserve includes a very simple indicator of its necessity; if it has not been in use during several peak situations, and if there seems to be reasonable amounts of flexibility in consumption, the strategic reserve can be terminated without further changes in the market framework.

The pros of a market wide capacity mechanism are that it solves the challenge of an anticipated adequacy problem. Some stakeholders could also consider it a pro, that the capacity market smoothens the price signal, thereby avoiding a debate about price spikes.

1.6.5 Con

The major con of a well-designed strategic reserve, as we see it, is that it slightly increases the total cost of electricity if it proves not to be necessary. Another con is that plants in the strategic reserve could have been viable in the market anyway.

For capacity markets, the cons are many. This is well-described in the White Paper from Germany; a capacity market is complicated, prone to market power, distorts the basic price signals (also in adjacent markets), increases regulation costs and regulation risks and is not the most efficient way to integrate renewables. Moreover, it can be difficult to return to an EOM, once the capacity market is implemented.

1.6.6 Recommendations

- The Nordic countries shall jointly, to the EU Commission communicate the benefits of a strategic reserve in comparison to other capacity mechanisms.
- Analyse whether activation of the Strategic Reserves should follow the German reasoning (no activation in the day-ahead market and activation as a last resort after ID-trade).
- Continuously improve market efficiency and sharpening price signals as elaborated in Markedsmodel 2.0, the Thema report and elsewhere.
- Implement an ambitious strategy for increasing flexibility in demand. Such a strategy should include energy taxes, grid tariffs and removal of barriers in the market (e.g. absence of hourly settlement for households) in order for new forms of contracts and services to develop. If deemed appropriate also directly incentivising the increase in demand response could be included, e.g. by promoting/supporting interruptible demand.
- Implement an analysis on a Nordic basis of the probability that sufficient imports are in fact available in peak load situations to Finland, SE3, SE 4 and DK 2 in the shorter term. One scenario should be extensive closures in the short term of condensing plants. The risk that Germany and Poland continues with extensive reductions in trading capacities to manage internal bottlenecks should also be analysed in this context.

- The possibilities to establish a common cross-border strategic reserve should be assessed.[6] Such a cross-border strategic reserve could include all the areas DK 2, FIN, SE 3 and SE 4 or some of these areas. Such a common cross-border strategic reserve could include minimum volumes in some bidding zones.
- Ensure that intelligent plans for forced load shedding is adopted among TSO's and DSO's in order to minimise the fear of capacity scarcity (We have not analysed to which extent this is already the case). A vision is that the TSOs/DSOs establish load-shedding plans based on voluntary agreements.

[6] Sharing of strategic reserves between bidding zones can be relevant when such zones are strongly interconnected.

2. EU framework regarding capacity mechanisms

2.1 Rules on state aid

The Treaty on the functioning of the European Union lays down the principle that state aid measures are prohibited. To qualify as state aid, a measure needs to:

- involve a transfer of aid from state resources
- entail an economic advantage for undertakings
- distort competition by selectively favouring certain beneficiaries
- have an effect on intra-community trade.

The rules on state aid are intended to ensure a level playing field for all industries within the EU by preventing some companies from gaining an unfair competitive advantage through government assistance. Despite the general prohibition of state aid, government interventions are in some circumstances necessary for a well-functioning economy. Therefore, the Treaty leaves room open for a number of policy objectives for which state aid can be considered compatible. Some exemptions are stipulated in EU legislation. If a state aid initiative is not automatically exempted, the Member State must notify it to the Commission, which alone determines whether the conditions for compatibility with the common market are fulfilled.

The Commission published in 2014 *Guidelines on State aid for environmental protection and energy (EEAG).*[7] Guidelines regarding capacity mechanisms were given in Section 3.9 Aid for generation adequacy. Key points from the Guidelines are summarised in the following paragraphs.

The *objective of common interest*, at which the measure is aimed, shall be clearly defined, including when and where the generation adequacy problem is expected to arise. The identification of a generation adequacy problem shall be consistent with the generation adequacy analysis carried out regularly by ENTSO-E.

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[7] http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52014XC0628%2801%29&from=EN

The need for *state intervention* to ensure generation adequacy shall be properly analysed and quantified. The Member State shall clearly demonstrate why the market cannot be expected to deliver adequate capacity in the absence of state intervention. The assessment shall include the impact of variable generation, the impact of demand-side participation and the impact of interconnectors. The assessment shall also include any other element which might cause or exacerbate the generation adequacy problem, such as regulatory or market failures, including for example caps on wholesale prices.

The state intervention shall be designed in such a way that it provides *appropriate and proportionate incentives* for operators to contribute to the solution. A capacity mechanism shall remunerate the creation of capacity, not sales of energy. The mechanism shall provide adequate incentives to both existing and future generators and to operators using substitutable technologies, such as demand-side response or storage solutions. Interconnection capacity as a remedy to the problem shall be considered. A capacity mechanism that does not influence operator behaviour is likely to be discarded, as the aid measure would then be disproportionate and would risk bestowing windfall profits.

Furthermore, the state intervention shall *avoid undue negative effects on competition and trade*. Negative effects due to export restrictions, wholesale price caps, bidding restrictions or other measures undermining the operation of market coupling shall be avoided. The measure shall not unduly strengthen market dominance. The measure should be designed to make possible the participation of operators from other Member States where such participation is physically possible.

2.2 Sector inquiry

The Commission launched April 2015 a state aid sector inquiry into capacity mechanisms. The focus of the sector inquiry is whether capacity mechanisms ensure a sufficient electricity supply without distorting competition or trade in the EU's Single Market.

In a sector inquiry, the Commission uses its market investigation tools to obtain the requested information from public authorities and market participants. While several antitrust sector inquiries have been carried out, also in the energy field, this is the first one motivated by state aid concerns.

The Commission selected Member States to include in the sector inquiry on the basis of three considerations:

- the existence of a capacity mechanism or plans to introduce a mechanism
- the need to include the various capacity mechanisms applied in the EU
- the impact of the existing or planned capacity mechanism on competition and cross-border trade.

Through the sector inquiry, the Commission wants to better understand the capacity mechanisms already implemented or under consideration. It will also assess and identify if there are certain design features of capacity mechanisms that distort competition between capacity providers or hinder trade across national borders.

Eleven Member States were initially selected, namely Belgium, Croatia, Denmark, France, Germany, Ireland, Italy, Poland, Portugal, Spain and Sweden. The Commission may extend the sample of Member States at a later stage if the preliminary results point to relevant developments in other markets. The UK was not included since the Commission approved the UK's capacity mechanism in July 2014.

The Commission informed that it will send different sets of questions to relevant public authorities in the selected Member States such as ministries, energy regulators and competition authorities and relevant market participants such as network operators, electricity generators, non-generation capacity providers, power exchanges and traders. It will then assess the replies.

At the launch of the sector inquiry, the Commission expected to publish a draft report for consultation around the end of 2015, and a final report in summer 2016.

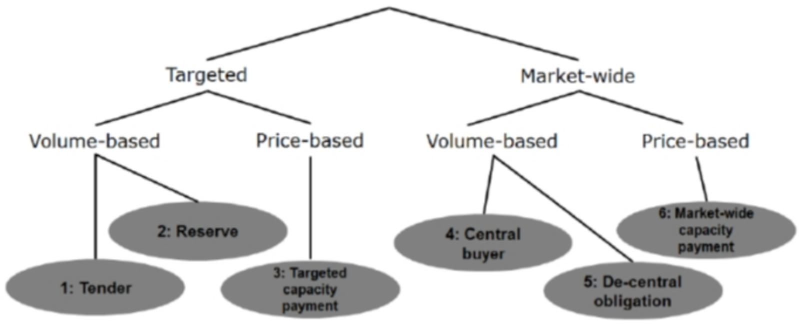
2.3 DG Competition working group with Member States

The Commission (DG Competition) has established a working group with Member States in order to facilitate implementation of the relevant provisions in the EEAG guidelines and to share experience in the design of capacity mechanisms. The context of the discussions is reflected in thematic papers developed by DG Competition.

The draft paper “High level comparison of capacity mechanism models and compatibility with State aid Guidelines”[8] was presented to a workshop 30 June 2015. The paper describes the different types of capacity mechanisms that have been proposed or implemented in Europe, and discusses the compatibility of their main design features with EEAG guidelines.

The paper groups six various forms of capacity mechanisms into two broad categories: targeted mechanisms and market-wide mechanisms. Within these two categories, volume-based mechanisms are distinguished from price-based mechanisms (cf. Figure 4).

Figure 4: Categorisation of capacity mechanisms in the DG Comp working paper



Targeted capacity mechanisms provide support only to the additional capacity expected to be required on top of what the market provides, rather than to the market as a whole. The capacity required and the volume expected to be brought forward by the market are determined centrally. The difference, or “top up”, is then procured through a capacity mechanism.

Three basic types of targeted mechanisms are identified:

1. Tender for new capacity - typically, the beneficiary of such a tender receives public financing for the construction of a power plant that brings forward the “top up” capacity. Once the plant is operational, in some models the “top up” capacity operates in the market as normal (without a guarantee that the electricity will be sold). In other cases, the plant receives a power purchase agreement meaning that it is paid for both its capacity and its electricity through the capacity mechanism.
2. Strategic reserve - in a strategic reserve mechanism, the top up capacity is contracted and then held in a reserve outside the market. It is only activated when specific conditions are met (for instance,

[8] http://ec.europa.eu/competition/sectors/energy/capacity_mechanisms_working_group_6_draft.pdf

when there is no more capacity available or electricity prices reach a certain level).

3. Targeted capacity payment - in this model, a central body sets the price of capacity. This price is then paid to a subset of capacity operating in the market, for example only to a particular technology, or only to capacity providers that meet specific criteria.

Both the strategic reserve and the tender for new capacity are volume-based mechanisms because the volume of capacity that receives support is determined at the outset. They differ from the price-based targeted capacity payment mechanism where there is no restriction on the amount of capacity that receives the payment, but instead a restriction on the type of capacity.

The working paper notes that all the three targeted mechanisms may be simpler to implement than market-wide mechanisms. The paper states for the three targeted mechanisms the following pros and cons.

A *tender for new capacity* could result in minimal market distortion if successfully implemented as a one-off measure. However, there is a risk that a tender reduces investor confidence and that future investors postpone investment to encourage further tender rounds that they can benefit from. Since a tender only corrects the missing money problem for selected new generators, and not for existing capacity providers, it could prompt closure of existing capacity and thus be entirely ineffective. Another disadvantage is that tenders are likely to lock in generation solutions and reduce opportunities for developing the demand side, interconnection and storage.

A *strategic reserve* may be useful for addressing problems of exceptional peak demand, while having minimal impact on market functioning. However, the price level at which the reserve is dispatched could become a price cap for the market, which will create a missing money problem if this price is less than consumers' value of lost load. If investor confidence is affected, this could lead to a need to increase the size of the reserve (the "slippery slope"). Existing plants could also threaten to close unless included in the reserve, also contributing to the slippery slope problem. Strategic reserve mechanisms may also bring about an inefficient use of resources since capacity held in reserve does not participate in the merit order which would ordinarily determine its dispatch. It is also difficult to see how a strategic reserve tender could enable new and existing capacity to compete effectively. A reserve limited to existing plants could end up supporting old plants longer than would be the case in an efficient market.

Targeted capacity payments supports a particular technology or capacity provider that meet specific criteria. However, the mechanism involves a large number of difficult calculations. Because of the difficulty in calculating the appropriate price level, this model is more likely than volume-based market-wide mechanisms to lead to either over- or under-investment, depending on whether the price is set too low or too high. In addition, given that the price is not calculated on the basis of a competitive bidding process, it may lead to overcompensation.

In a *market-wide mechanism*, all participating capacity receives payment, including both existing and new providers of capacity. This essentially establishes "capacity" as a product separate from "electricity".

Three basic types of market-wide mechanisms are identified:

1. Central buyer - where the amount of required capacity is set centrally, and then procured through a central bidding process so that the market determines the price. This mechanism provides support to all (or at least the majority of capacity providers in the market - there may still be some restrictions on eligibility for example because some market participants receive alternative support).
2. De-central obligation – where an obligation is placed on market participants (suppliers/retailers) to contract with capacity providers to secure the capacity they need to meet their consumers' demand (e.g. an obligation to contract capacity certificates or reliability options). The difference compared to the capacity market model is that there is no central bidding process to establish the price for the required capacity volumes.
3. Market-wide capacity payment – where the price of capacity is set centrally, based on central estimates of the level of capacity payment needed to bring forward sufficient investment.

The central buyer and de-central obligation models are volume-based. The volume of capacity required is set centrally, while the price is determined by the market. The market-wide capacity payment is price-based since the price level expected to result in sufficient investment is fixed at the outset, while the volume may vary depending on how the market reacts to that price. The paper states for the three market-wide mechanisms the following pros and cons.

A *central buyer* mechanism should transparently establish the sustainable market price for capacity. The model offers the option to include long-term contracts/agreements which may be necessary to encourage new capital-intensive projects and enable competition between new and existing capacity. However, the mechanism requires significant market intervention and complex rules. The mechanism may be difficult to adapt and/or remove, particularly if long-term contracts have been awarded.

A *de-central obligation* mechanism may be easier to implement as it reduces the need for complex design and reduces the need for central calculations. Furthermore, if penalties are sufficient, the mechanism should provide a good incentive for suppliers to accurately judge the amount of capacity required. There is a potential for the market to develop different capacity products that allow suppliers to more efficiently meet their obligation. However, the mechanism requires significant market intervention and the development of complex rules (though perhaps less complex than a central buyer mechanism). Unless the design includes long contracts/agreements it may not encourage new investment. The mechanism may increase incentives for vertical integration and present a barrier to entry for independent capacity providers and electricity suppliers.

A *market-wide capacity payment* may be simpler to implement than other market-wide measures. However, the mechanism involves a large number of difficult central calculations which are subject to error (not only the volume required, but also the price expected to be sufficient to bring forward this volume). Furthermore, because of the difficulty to calculate the appropriate price level, this model is more likely than amount-based market-wide mechanisms to lead to either over- or under-investment, depending on whether the price is set too low or too high. In addition, given that the price is not calculated based on of a competitive bidding process, it may lead to overcompensation.

The draft paper lists issues regarding the mechanisms *compatibility with the EEAG guidelines.*

Regarding the central buyer model, the draft paper concludes that it will require careful assessment but could meet all EEAG requirements.

Point 226 of the EEAG requires capacity mechanisms to provide adequate incentives to both existing and future generators and to operators using substitutable technologies. The extent to which interconnection capacity could remedy the generation capacity problem shall also be taken into account. Tender for new capacity does not meet this requirement. Depending on the eligibility criteria, the same may apply to targeted capacity payments. Depending on its design – for example the lead time between the tender process to establish the reserve and the point in time when the reserve must be available – a strategic reserve may fail to provide adequate incentives to future generators. The extent to which a de-central supplier obligation enables new and existing providers of capacity to compete needs to be carefully assessed.

The administrative price setting and lack of a competitive bidding process in the market-wide capacity payment mechanism is likely to be insufficient to demonstrate proportionality (point 228 of the EEAG) without an individual assessment of each beneficiary.

A de-central obligation mechanism may lead to overcompensation (paid by consumers) if generators or retailers have market power (see points 230 and 233(d) EEAG).

A strategic reserve may not meet point 231 of the EEAG, according to which the price paid for availability automatically tends to zero when the level of capacity supplied is expected to be adequate to meet the level of capacity demanded.

Depending on the eligibility rules, a tender for new capacity and targeted capacity payments may struggle to meet the requirements related to technology neutrality (point 232 EEAG).

Point 232(c) requires the establishment of a competitive price for capacity as part of avoiding negative effects on trade. An administrative price setting in the targeted capacity payment mechanism and the market-wide capacity payment mechanism may not provide sufficient reassurance in this regard.

If a mechanism prompts the closure of existing capacity it could not be considered appropriate.

DG Comp presented to the workshop 30 June 2015 also the draft paper "Enabling the participation of interconnectors and/or foreign capacity providers in capacity mechanisms".[9] This paper compiles the requirements in EEAG related to the participation of interconnectors and/or operators in other Member States in capacity mechanisms. It identifies some of the main design questions that must be addressed by a Member State. It also explores the form that common rules could take and the questions that would need to be addressed to further develop such an approach.

The EEAG include the following requirements related to cross-border participation in a generation adequacy measure:

- Take into account to what extent interconnection capacity could remedy any possible problem of generation adequacy (EEAG 226).
- Be open to interconnectors if they offer equivalent technical performance to other capacity providers (EEAG 232 a).
- Be open to participation of operators from other Member States where such participation is physically possible in particular in the regional context (EEAG 232 b).

[9] http://ec.europa.eu/competition/sectors/energy/capacity_mechanisms_working_group_6_draft.pdf

- Not reduce incentives to invest in interconnection capacity (EEAG 233 a).
- Not undermine market coupling (EEAG 233 b).

The aim of these requirements are presented:

- The more participation in a capacity mechanism, the more competitive it should be and therefore the higher the chance that the mechanism provides value for money for consumers.
- If the contribution of imported electricity is not taken into account when capacity is procured through national capacity mechanisms, this would result in significant overcapacity.
- If cross border participation in capacity mechanisms is not enabled, there will be greater distortion of the signals for where new capacity should be built, and an increase in overall system costs. And capacity mechanisms will fail to adequately reward investment in the interconnection that allows access to capacity located in neighbouring markets.
- If cross border participation is enabled by requiring physical delivery of electricity into a particular market, there is a risk that the market coupling rules (which ensure the most efficient use of interconnection) are undermined. There is also a risk of distorting the merit order in neighbouring markets.

When the demand requirement is set in a capacity mechanism, the total capacity demanded can be adjusted to account for expected imports (at times of scarcity). This meets the basic requirement of EEAG 226, but may not meet the requirements of EEAG 232 because it does not actually enable interconnector participation, and would not provide any remuneration for the value of foreign capacity to the market unless the value of capacity is somehow paid to existing and/or new interconnectors.

The approval of the UK scheme for the GB Capacity Market was contingent on the inclusion of interconnected capacity from the second annual auction.

The paper notes that it may be necessary to de-rate the interconnectors and/or foreign capacity eligible to participate according to the extent to which their capacity can be physically provided at times when it is needed in the capacity mechanism zone. More rules or guidance on derating of interconnectors may be required – particularly to assist with derating in complex flow based coupled systems.

With the interconnector as counterparty, it is not clear according to the paper that an availability model delivers appropriate revenues to foreign capacity providers. The most appropriate design choices may therefore be to enable foreign capacity to participate directly, with no delivery obligations imposed on either the foreign capacity providers or the interconnector operator.

A tentative harmonised approach to cross border participation in volume-based market-wide capacity mechanisms is presented in order to stimulate discussion. The approach is very complex and includes implicit market coupling between different capacity zones or explicit auctions of tickets allowing entry into another zone with a capacity mechanism.

The paper has also a short discussion regarding harmonised rules for strategic reserves and finds that capacity could in theory be procured in a neighbouring bidding zone. However, this would only help security of supply in the country paying for the reserve in certain circumstances. The dispatch of a strategic reserve should push prices in the market to the price cap, because this should reflect the value of electricity at a time when delivery of the reserve capacity is required. There will in such a case be full import (if there is no scarcity in the neighbouring zones) independent of whether reserves are procured in these zones or not. The paper asks therefore if cross border participation can be enabled effectively for other capacity mechanism designs, or only for volume-based market-wide designs.

2.4 Consultation on Summer package

As part of the Energy Union strategy, a public consultation on a new energy market design was launched in July 2015 by the Commission. The consultation raised some questions related to security of electricity supply. The consultation closed on 8 October 2015. The Commission received more than 320 replies and is now in the process of assessing the answers. It is preparing an Impact Assessment on their proposals by June 2016.

The Directorate–General for Economic and Financial Affairs (DG ECFIN) has also been active in this field. It published July 2015 the report "Energy Economic Developments – Investment perspectives in electricity markets"[10] as a staff working document accompanying the consultation on the summer package.

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[10] http://ec.europa.eu/economy_finance/publications/eeip/pdf/ip003_en.pdf

One session in the Florence Forum[11] on 9 October 2015 dealt with capacity mechanisms in the new market design. The Forum noted in its conclusions[12] that capacity remuneration mechanism might be warranted under certain circumstances, notably when they are linked to a regional assessment and do not undermine price signals. The Forum identified that the most important elements to be addressed are: the need for a common European methodology to generation adequacy; development of a common definition of reliability standards; a framework for cross-border participation and demand side; and governance issues.

The Forum took note of the Commission's plans to provide a European framework for an enhanced system adequacy assessment and for cross-border participation in national capacity remuneration mechanisms. The Forum invited the Commission to take particular account of physical limitations, value for money for consumers, and administrative regimes.

The next Florence Forum is planned to be held on 3–4 March 2016. It has been said from the Commission that they want to use the Forum to test their ideas on proposals to address the new energy market design.

2.5 Possible compatibility issues with future EU framework regarding capacity mechanisms

All planned capacity mechanisms can be defined as state aid and have thus to satisfy the requirements in the EEAG Guidelines. These requirements are far-reaching and are to some extent conflicting. None of the planned capacity mechanisms are perfect in relation to EEAG.

The EU framework regarding capacity mechanisms is under development as described earlier in this section. Many new rules and guidelines will probably be proposed this year. More definitive conclusions should therefore not be drawn at this moment. Nevertheless, we will based on the European discussion during 2015 try to list some issues or demands which we think will be important when designing capacity mechanisms:

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[11] The Electricity Regulatory Forum (Florence Forum) was set up to discuss the creation of the internal electricity market. Participants include national regulatory authorities, Member State governments, the European Commission, TSOs, electricity traders, consumers, network users, and power exchanges. Since 1998 the Forum has meet once or twice a year.

[12] https://ec.europa.eu/energy/sites/ener/files/documents/Conclusions_29_FF.PDF

- Security of supply will be very important in the European Union strategy. Capacity mechanisms may therefore be wanted under certain circumstances and has to be implemented in such a way that security of supply is not jeopardized.
- The objective and the need for a capacity mechanism shall be assessed on a regional basis instead of a national basis.
- Common European methodology for generation adequacy assessment (including possible imports and demand flexibility in scarcity situations) is needed.
- Framework for demand-side participation.
- Framework for cross-border participation.
- The mechanism must not undermine price signals.
- Governance issues.

One very important issue is whether the Commission will favour a targeted or a market-wide mechanism. DG Comp seems so far to favour market-wide mechanisms since it believes that the more participation, the more competition. Others have seen the risks for the energy market in such a development[13] and have therefore preferred a targeted mechanism as a strategic reserve since it can be combined with an energy-only market. We do not expect that the Commission will make a clear choice this year. We expect therefore that both market-wide mechanisms and targeted mechanisms will be possible.

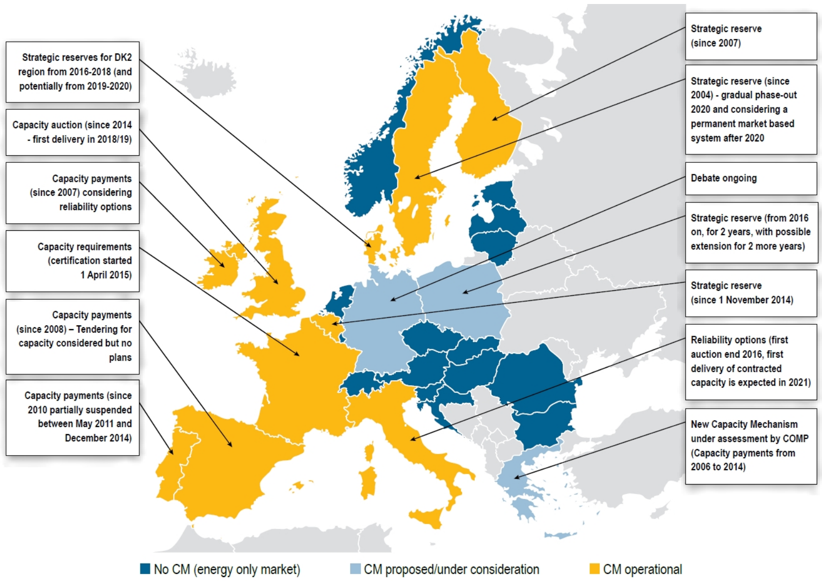
[13] An in-depth analysis of these risks was e.g presented 2015 by the German Federal Ministry for Economic Affairs and Energy (BMWi) in its white-paper An Electricity Market for Germany's Energy Transition.

3. Capacity mechanisms in selected European countries

Capacity mechanisms are a hot subject in security of supply debates across Europe. Several new capacity mechanisms are currently being implemented. In places where they are not, existing mechanisms are either in revision or up for debate. An overview of the current European capacity mechanism situation is given in the map below.

This chapter presents in detail the capacity mechanisms being implemented in Germany, France, the UK, and Italy.

Figure 5: Capacity Mechanisms in Europe – 2015



Source: Acer (2015).

3.1 United Kingdom

3.1.1 Background

With the Energy Act of 2013, the United Kingdom (UK) set out an Electricity Market Reform (EMR). Amongst other issues, this reform aims to tackle an expected capacity crunch in the years to come. Within the next five years alone, it is estimated that GBP 100 billion of private sector investment is needed in order to replace an ageing electricity infrastructure with a new and low-carbon energy supply.[14] In order to deal with the associated security of supply issue and incentivize investments in new capacity, the UK EMR included a capacity mechanism in the shape of a centralized capacity market.

3.1.2 The UK capacity market[15]

The UK has opted for a central capacity market in Great Britain in which a target capacity level is procured through auctions by the system operator, National Grid. The capacity target level is ultimately set by the Government, but National Grid provides annual recommendations about the level of capacity that is needed in order to meet the Government's reliability standard with respect to security of supply. Currently, this reliability standard is set at a maximum loss of load expectation (LoLE) of 3 hours per year.[16]

Successful auction participants commit to the delivery of electricity (or demand reduction) – the capacity obligation – when called upon by National Grid in times of system stress during the contract period. Failure to comply with the obligation entails penalties. In return, successful participants receive an annual payment corresponding to the auction clearing price (GBP/MW) multiplied by the winning bids of capacity providers measured in (MW). The payment is spread over the contract period, which vary for different capacity types. Contract periods are 1 year for existing capacities, while they are longer for refurbishment capacities (3 years) and new capacities (max. 15 years).

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[14] National Grid (2015a).

[15] The UK capacity market is for Great Britain, and does not include Northern Ireland.

[16] LoLE definition: the expected number of hours when demand is higher than available generation during the year (National Grid, 2015a).

The UK capacity market will consist of two annual auctions, when it is fully operational:

- *The T-4 auction*: In this auction, 4 years ahead of delivery, the majority of the capacity target is auctioned off. A smaller share of the target capacity is set aside for later adjustments to the target capacity, and to include Demand-Side Response (DSR) capacities for which it is difficult to reliably predict availability 4 years in advance.
- *The T-1 auction*: In this auction, 1 year ahead of delivery, the adjusted residual capacity – relative to the target capacity and the capacity included in the T-4-auction – is auctioned off.

Box 1: Timing of the UK capacity mechanism

- The first T-4 auction was held in 2014, with delivery in 2018.
- The second T-4 auction was held in 2015, with delivery in 2019.
- The first T-1 auction will be held in 2017, with delivery also in 2018.

In addition

Two transitional auctions – with lead-times of 1 year – limited to DSR capacities will be held in 2015 and 2016, in order to promote the future capacity market competitiveness of DSR.

Source: Ofgem (2015a).

Between the auction time and delivery (delivery year included), participants can adjust their positions through secondary trading of their obligations. Secondary trading includes volume reallocation, obligation trading and financial trading.[17]

[17] Secondary trading options are meant as instruments for capacity providers to manage the risks related to the penalty exposure embedded in the UK capacity market. The rules governing the use of these instruments are currently in revision prior to the 2016 capacity market auctions in order to facilitate easier trading (DECC, 2015a). *Volume reallocation* is an option for capacity providers in charge of capacity market units (CMUs) (cf. also section 2.2.2) that have delivered output in excess of its obligations during a stress event to reallocate said volume to another CMU that did not meet its obligation. It is an alternative to receiving over delivery payments. *Obligation trading* allows capacity providers to transfer their capacity obligation to another party. *Financial trading* refers to the option for capacity providers to freely hedge the risks associated with their capacity obligation outside the capacity market. It is meant to fill any risk-related gaps that are not already covered by volume reallocation and obligation trading.

3.1.3 Capacity market demand

National Grid provides recommendations to the UK Government on the target level of de-rated capacity[18] for the delivery year, which is needed to ensure a maximum LoLE of 3 hours per year. These recommendations are based on a two-step procedure.

The first step applies a model-based approach (cf. Box 2) to determine the required amount of de-rated capacity that is necessary to reach a maximum LoLE of 3 hours per year. In the modelling, National Grid uses different energy scenario assumptions. The main elements that vary across scenarios include demand (annual and peak), and generation mix assumptions. To a large extent, the generation mix assumptions concern the roll-out of renewable-based generation capacity. While most renewable-based capacities are currently ineligible to participate (cf. box 4), their contribution to security of supply is taken into account through National Grid's modelling approach.

Box 2: The DDM model

The model used by National Grid to determine the capacity to procure in the capacity market auctions is an electricity supply model called the dynamic dispatch model (DDM).

The DDM intends to explicitly model the capacity market auctions. Based on modelled revenues and expenditures of all existing and new capacities, the model estimates their respective auctions bids.

The DDM follows a step-wise procedure for the purpose of recommending the target level of capacity to procure. Simplified, the DDM determines the amount of available capacity four years ahead, with given scenario assumptions. This information is then used, in combination with the expected availability of conventional generation capacity and the equivalent firm capacity contribution from wind turbines and interconnections, to stochastically model the dispatch of the energy system.

For each increasing (modelled) capacity market auction bid, the model assesses the corresponding LoLE for the modelled energy system. The recommended capacity to procure is determined by the level of capacity that corresponds to the target LoLE of 3 hours per year – the government's security of supply reliability standard.

Source: National Grid (2015a).

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[18] De-rated capacity refers to the average expected level of available capacity. It is calculated for generators (or DSR capacities) for different technology classes relative to nominal or "nameplate" capacity.

The second step decides which of the model-based capacity choices (output from the first step) should be the basis of its recommendation to the Government. National Grid bases its recommendations on a Least Worst Regret approach (LWR) (cf. Box 3). This approach estimates the maximum regret costs associated with each potential capacity procurement choice given certain contingencies, which would lead to either over or under procuring capacity. The capacity choice chosen is the one that minimizes the maximum regret costs.

Box 3: The Least Worst Regret (LWR) Approach

The LWR approach used by National Grid determines the maximum regret costs associated with either over or under procuring capacity in the scenarios that they define as input to the DDM model simulations (cf. Box 2), given certain contingencies.

If the LoLE – the government's security of supply reliability standard – exceeds 3 hours per year after taking contingencies into account, too little capacity is procured. In the reverse case, where the LoLE is below 3 hours per year, too much capacity is procured.

The scenario with the lowest maximum regret costs is the scenario chosen by National Grid as its recommendation of the level to procure to the government.

In order to derive the maximum regret costs associated with each contingency, National Grid estimates the unit cost of Expected Energy Unserved (EEU) with a value of lost load (VoLL) of 17,000 GBP/MWh, and the unit-cost of derated capacity with a net CONE (cost of new entry) estimate of 49,000 GBP /MW/year (2012-prices).

Source: National Grid (2015a).

With National Grid's recommended capacity target for the delivery year in hand, the government decides on the auction demand. Doing this, a range of adjustments are made. First, the government decides on the respective demands for the T-4 and the T-1 auctions. Second, the government adjusts the T-4 auction demand to take into account the capacity which is either known or expected to opt-out of the auction(s), but remain operational in the delivery year. Third, the government adjusts the auction demand to reflect the size of the existing short-term operating reserve. A prequalification process informs the level of adjustments. As a final measure, the government defines a tolerance range of +/- 1.5 GW around the final target demand.[19]

Additionally, the government classifies auction participants as either price takers (existing capacities) or price makers (new and DSR capacities), in order to restrict the maximum bids of the two groups. Price takers are not allowed to bid above a pre-set threshold price (GBP 25/kW/year in the 2014 T-4 auction), and price makers are not allowed to bid above the auction price cap (GBP 75/kW/year in the 2014 T-4 auction). Both price restrictions are set by the government. This method is chosen to mitigate potential marker power issues.[20]

3.1.4 Capacity market supply

Eligibility for participation in the capacity auctions is determined through a pre-qualification process for Capacity Market Units (CMUs). The main purpose of the pre-qualification process is to ensure that auction participants are capable of delivering the de-rated capacity that they offer in the delivery year. CMUs are either units of de-rated electricity generation capacity or units of manageable electricity demand, and include existing and new generation capacities, DSR and storage operator capacities, as well as interconnector capacity.[21]

The UK capacity market is technology neutral, but it is a participation requirement that CMUs do not already receive other support measures. As a consequence, this currently rules out most RE-based capacities (cf. Box 4).

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[19] National Grid (2015).

[20] These are the core parameters that influence the government's choice of demand curve. For additional information, see e.g. EU (2014).

[21] Interconnector capacities are allowed to participate in the UK capacity market from 2015 and onwards. The bidding capacity of an interconnector – its de-rated capacity – is determined in the pre-qualification procedure where the government applies both historical and forecasting methodologies in order to determine the expected import availability of power from each connected market during times of system stress. If interconnectors are based in countries dealing with known security of supply issues, this is taken into account by additional capacity de-rating. The government further adjusts the de-rated interconnector capacities according to each interconnectors technical reliability (DECC, 2015b; National Grid, 2015a).

Box 4: Eligible capacity types in the UK capacity market

CMUs are not eligible to participate in the capacity auctions if they receive other state aid measures, e.g. the UK Feed-in Tariffs (FiTs), Contracts for Differences (CfDs), Renewables Obligations (ROs), and the Renewable Heat Incentive (RHI).

As a consequence, this currently rules out auction participation for:

- Wind power.
- Solar PV.
- Most biomass plants.
- New nuclear capacity (i.e. Hinkley Point).
- More.

However, the contribution to security of supply from these capacity types are factored into the capacity market demand, as their contribution is modelled explicitly in the DDM that National Grid uses as its basis for capacity target recommendations to the government.

Source: National Grid (2015a), EU (2014).

3.1.5 Delivery obligation

Contracted capacities are obliged to deliver electricity (generation or demand reduction) during system stress events.[22] Penalty charges are imposed in the case of failure to fulfill the obligation when the system operator has published a "Capacity Market warning", at least four hours prior to the system stress event.

3.1.6 Penalties

The UK capacity mechanism includes two main penalty types; termination fees and penalty charges.

If a capacity agreement for new (unbuilt at the time of the auction) capacity is terminated, two context-specific termination fees apply the TF1 (GBP 5,000/MW) and TF2 (GBP 25,000/MW). The TF1 applies mainly to prospective CMUs that fail to meet pre-defined milestones (e.g. milestones related to financing, grid-connection agreements and metering tests) in the

[22] "System stress events are defined as any half hour settlement periods in which either voltage control or controlled load shedding are experienced at any point on the system for 15 minutes or longer" (EU 2014, p. 14).

construction of new capacities that have entered into capacity market contracts. The TF2 applies to prospective generation and interconnector CMUs that fail to reach a minimum completion requirement (MCR).[23,24]

Failure to fulfill the capacity obligation implies penalty charges, which are calculated for each month of the delivery year (similar to the both the capacity payment and the supplier charge used to finance the UK capacity market). Main elements in the calculation of the penalty charges include monthly and annual penalty limits relative to annual capacity payments (20 and 100 percent, respectively). As a consequence, the penalty charges can never exceed the capacity payments on an annual basis.[25]

The payment and penalty regime of the UK capacity market contains additional elements such as penalties associated with failure to deliver sufficient electricity for performance demonstrations during non-stress events, and additional payments for over-delivery during system stress events.

3.1.7 Financing

The capacity mechanism is financed through a capacity market supplier charge for all licensed suppliers. The charge is determined to correspond to the demand between 4–7 pm of each licensed supplier on winter weekdays, in order to incentivize demand reductions during hours of peak demand.

Prior to delivery, the supplier charge will be determined based on forecast market shares. When consumption data is available, the charge will be adjusted accordingly. In addition, the charge will be profiled according to system demand, such that it is higher during winter time. This payment profile is made to mirror the actual payments to capacity providers, which receive higher payments during periods of high demand.[26]

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[23] The penalty rules are highly complex. For further information, see the Electricity Capacity Regulations 2014 (UK Gov, 2014).

[24] The MCR states that prospective generation and interconnector CMUs must provide at least 50 percent of the capacity stated in its capacity obligation 18 months after the start of the first relevant delivery year, or face termination as well as the TF2 penalty. If the 50 percent threshold is reached, but not the full obligation, the obligation will be scaled down accordingly.

[25] EU (2014).

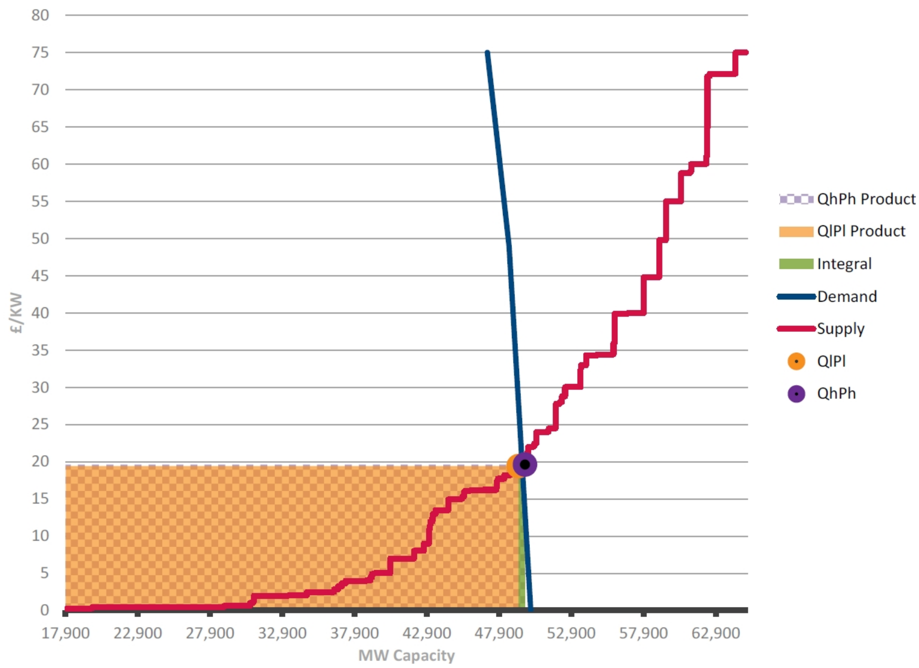
[26] EU (2014).

3.1.8 *Results from the first T-4 auctions*

As of December 2015, two T-4 auctions have been held – both with effective obligations four year later.

The first auction was held in December 2014 and cleared at a price of GBP 19,400/MW/year (2012-prices) with a clearing capacity of 49.3 GW (cf. Figure 6). This clearing price was 50 percent lower than government expectations.[27] The second auction was held in December 2015, and (provisional) results indicate that results align with the outcome of the 2014 auction, with a clearing price of GBP 18,000/MW/year (2014/15 prices) and a clearing capacity of 46.3 GW[28] (cf. Figure 7).

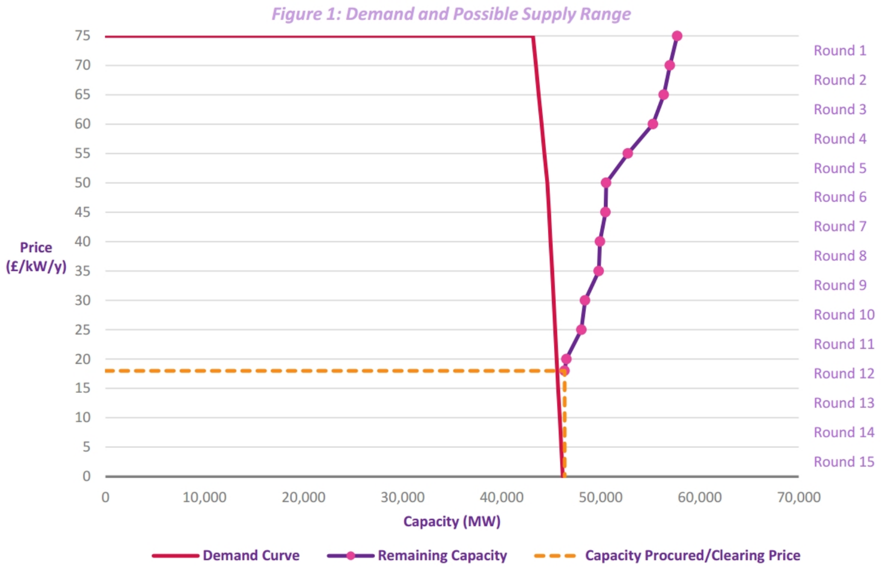
Figure 6: Clearing Price and Capacity in the 2014 T-4 Capacity Market Auction



Source: National Grid (2015b).

[27] Ofgem (2015b).
[28] National Grid (2015c).

Figure 7: Clearing Price and Capacity in the 2015 T-4 Capacity Market Auction



Source: National Grid (2015c).

Striking similarities exist between the two auction outcomes with respect to the distribution of capacity agreements by CMU types (cf. Table 3). The majority of capacity agreements were won by gas (45–47%) and nuclear plants (16%). Main differences in the 2015 auction include the capacity agreements awarded to the existing French-British interconnector, to coal plants (a reduction) and to DSR operators, of which the far majority, however, has not been proven functional yet.

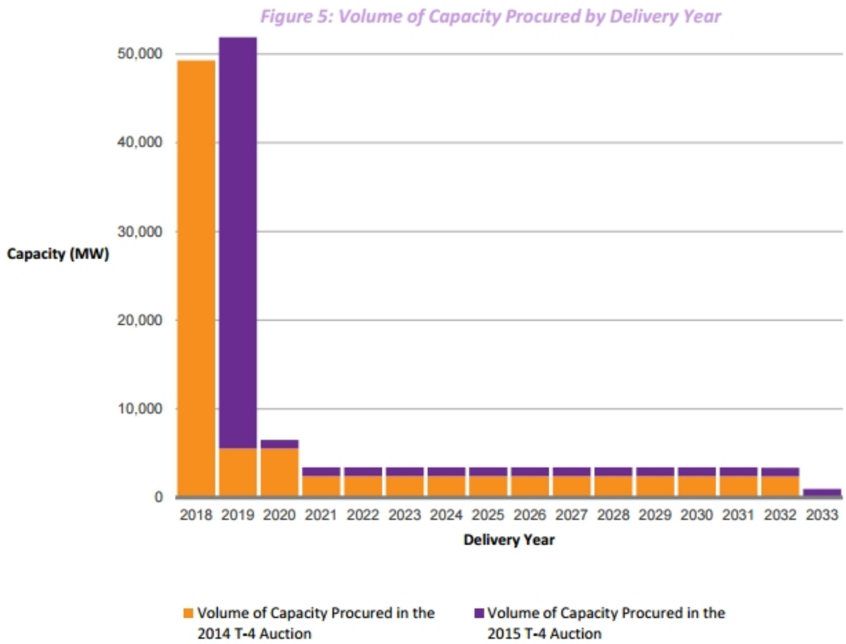
Table 3: Successful CMUs by type in the 2014 and 2015 T-4 Capacity Market auctions

CMU type	2014 (GW)	(%)	2015 GW	(%)
CCGT	22.3	45.2	21.8	47.1
CHP and autogeneration	4.2	8.6	4.2	9.1
Coal/Biomass	9.2	18.7	4.7	10.1
DSR	0.2	0.4	0.5	1.0
Hydro	0.7	1.4	0.7	1.5
Nuclear	7.9	16.0	7.6	16.3
OCGT and Reciprocating Engines	2.1	4.3	2.4	5.2
Storage	2.7	5.5	2.6	5.7
Interconnector	0.0	0.0	1.9	4.0
Total	*49.3*	*100.0*	*46.3*	*100.0*

Source: National Grid (2015b) and National Grid (2015c).

In both auctions, the majority of contracted capacity consists of existing and prospective refurbished capacities. New capacities only make up a minor share of roughly 5 percent (cf. Figure 8). Recall that the contract periods awarded to existing (1 year), refurbished (3 years), and new (max. 15 years) capacities vary.

Figure 8: Agreement Durations from the 2014 and 2015 T-4 Capacity Market auctions



Source: National Grid (2015c).

3.2 Germany

3.2.1 Background

Germany is currently undergoing an energy transition (*Energiewende)* involving the phase-out of nuclear energy in 2022, a strong roll out of renewable energy and a growing integration and therefore dependence on the greater European electricity market. With this transition, security of supply issues have come into focus.

The Federal Ministry for Economic Affairs and Energy (BMWi) released a Green Paper in 2014 suggesting options for a revision of the current electricity market.[29] The Green Paper pointed out two different approaches to ensuring a secure electricity supply. The first approach involved an energy-only market entitled "Electricity Market 2.0", in which barriers to the delivery of correct price signals are removed. The second approach involved the creation of a capacity market in addition to the energy-only market.

After consultations with a broad range of stakeholders, the BMWi decided for the former – an "Electricity Market 2.0" – and presented this decision in the 2015 White Paper.[30] As an additional safeguard, this reformed electricity market contains a capacity reserve that will only be activated as a last resort.

The German decision against the capacity market, instead favoring an electricity market reform and a strategic reserve option, is based on a three-fold argument.

Box 5: The three-fold argument for the strategic reserve option chosen in Germany

Argument 1

The BMWi believes that a reformed electricity market can deliver a secure electricity supply. In the short term, the current electricity supply is characterized by overcapacity; in the range of 60 GW in the German and European electricity market. In the longer term, the integration of electricity markets across Europe implies large-scale smoothing effects with respect to both peak loads and production from renewables, reducing the need for capacity. This latter argument is based on recent ENTSO-E findings.

In addition, the BMWi does not believe that the current electricity market is an energy-only market in which only the delivery of electricity is remunerated. In its current shape, it is argued, capacity is already remunerated both implicitly and explicitly. The implicit element arises through the unconditional supply commitments on futures- and spot markets and through electricity purchase contracts. The explicit element arises through the capacity remuneration of the balancing capacity market and through select financial contracts such as options and hedging contracts. This capacity remuneration contributes to the coverage of fixed costs (elaborate arguments can be found *in Part II of the White Paper*).

[29] BMWi (2014).
[30] BMWi (2015a).

Argument 2
Reforming the electricity market into an "Electricity Market 2.0" – including a strategic reserve – is simply cheaper than opting for a capacity market. A main reason relates to the complexity of designing capacity markets leading to a combination of high regulatory costs, and the likelihood that too much capacity will be procured. The BMWi further argues that an undistorted price signal in the market is the most cost-efficient way of integrating renewables, as flexibility options will compete on even and technology-neutral terms. This latter aspect is hard to establish in a heavily regulated market such as a capacity market.

Argument 3
Innovation and sustainability is cost-efficiently promoted through the "Electricity Market 2.0" by leaving the price signal undistorted. For example, a system with a high share of renewables require innovative flexibility technologies such as demand-response, and the development hereof is best incentivized by an undistorted price signal. In contrast, the introduction of new flexibility options in a regulated market is difficult, as the regulator will have to define the terms and conditions of trading and pricing. The BMWi argues that this happens at the risk of the regulator basing its approach on information about existing technologies, which in turn distorts the competition in favor of existing technologies.

Source: BMWi (2015a).

3.2.2 The German capacity reserve

The capacity reserve in Germany will consist of technically suitable power plants that are not active on the electricity market, and which are not likely to be commercially operable. The system operators will procure the reserve through competitive tenders.

The capacity reserve is expected to amount to roughly 5 percent of the anticipated average annual peak load. Currently, this is about 4 GW of installed capacity.

Box 6: The Temporary Lignite Reserve

As an exception to the general rules of the capacity reserve, 2.7 GW of currently active lignite capacity is temporarily placed in the capacity reserve starting in 2016. The government introduces this measure in order to ensure the fulfillment of the German 2020 Climate goals.

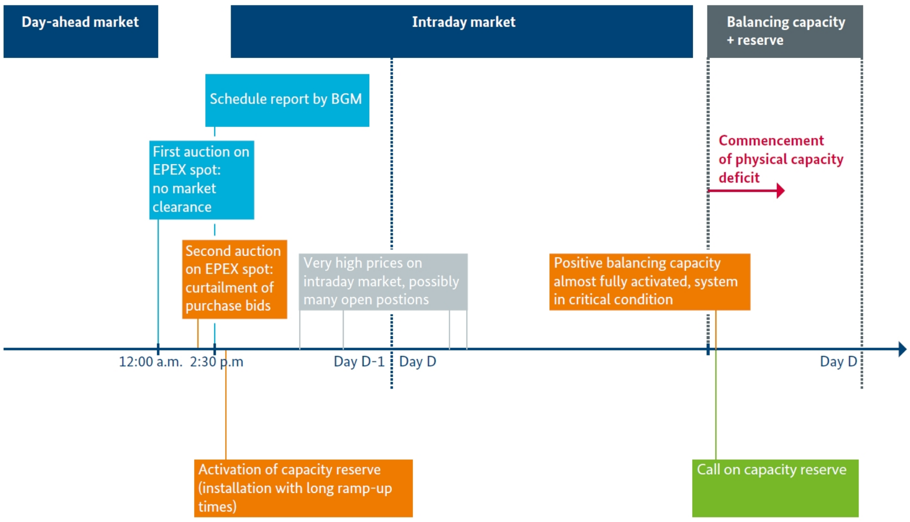
In October 2015, the BMWi announced that agreements had been made with Mibrag, RWE, and Vattenfall concerning the procurement of 2.7 GW lignite-fired power plants.

Whether the temporary lignite reserve actually constitute a capacity reserve is an open question. According to ACER, the German Bundesnetzagentur is not so sure.

Source: BMWi (2015b), ACER (2015).

The capacity reserve will work as a last resort. It is only activated if the day-ahead market, the intraday market, and the balancing capacity reserves of the system operator proves insufficient to meet demand. However, plants with long ramp-up times may be activated in such time after the day-ahead market that they are able to deliver needed capacity (cf. Figure 9).

Figure 9: Deployment Schedule of the Capacity Reserve



Source: BMWi (2015a).

3.2.3 Financing

The capacity reserve will be financed according to a user-pays – or cost-causality - principle. If the reserve is not activated, the reserve-costs will be shared amongst all electricity consumers. If the reserve is activated, a percentage of the reserve-costs – reflecting the contribution to the need to activate the reserve – will be allocated to electricity suppliers who failed to meet their supply obligation.[31] This is done in order to motivate suppliers to cover their supply obligation early on through either futures contracts or demand response arrangements. If the reserve is activated, it will happen at a minimum price of EUR 20.000 per MWh – twice the maximum technical price in the intra-day market. Billing will take place through the established balancing capacity system.[32]

3.2.4 The grid reserve

Congestion problems are often present within Germany. The common bidding zone for Germany and Austria results in a high demand for transmission of power from north to south when there is high wind production. The planned grid investments are seriously delayed and congestion problems are therefore solved through redispatch ordered by the TSOs (reduced power production in the surplus area and increased power production in the deficit area) and limitations of cross-border capacities. In order to have sufficient possibilities for redispatch and maintaining grid security, the German TSOs have contracted non-active power plants in the South to a grid reserve.

According to the White Paper, the capacity reserve and the grid reserve are two different instruments. The capacity reserve is a German-wide instrument while the grid reserve is a regional instrument which expires when the planned grid investments are executed. The lifetime of the grid reserve will be extended to 2023 when the most important grid expansion projects are expected to be finalized. The costs for the capacity reserve are paid by the suppliers while the costs for the grid reserve are included in the grid tariff and paid by the grid consumers.

The procurement of the capacity reserve will be followed by the procurement of the grid reserve. This implies that after the procurement of the capacity reserve, the TSOs will account for the share that is located in the

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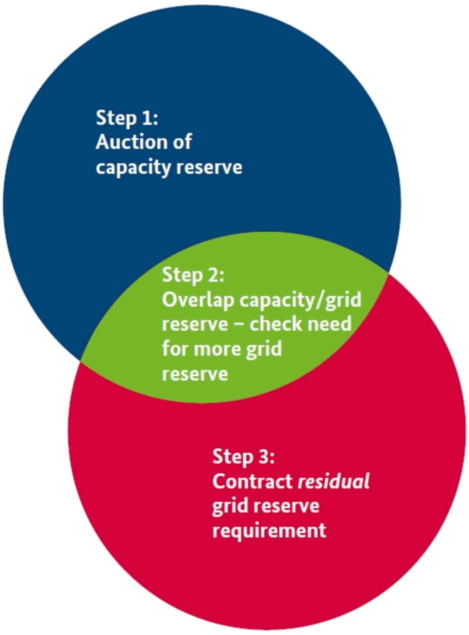
[31] The supply obligation refers to the commitments of balance responsible parties. In Germany, balance responsible parties (e.g. electricity suppliers) are responsible for the quarter-hour balancing of supply and demand. Imbalances such as insufficient supply are dealt with by activating balancing capacity (see also BMWi, 2015a, p. 39).
[32] BMWi (2015a).

South. If it is a sufficient share, no additional grid reserve will be needed. If the share is insufficient, the TSOs will contract reserve agreements with additional power plants in the South for the grid reserve (cf. Figure 10).

Figure 10: : Dovetailed Procurement of the Two Reserves



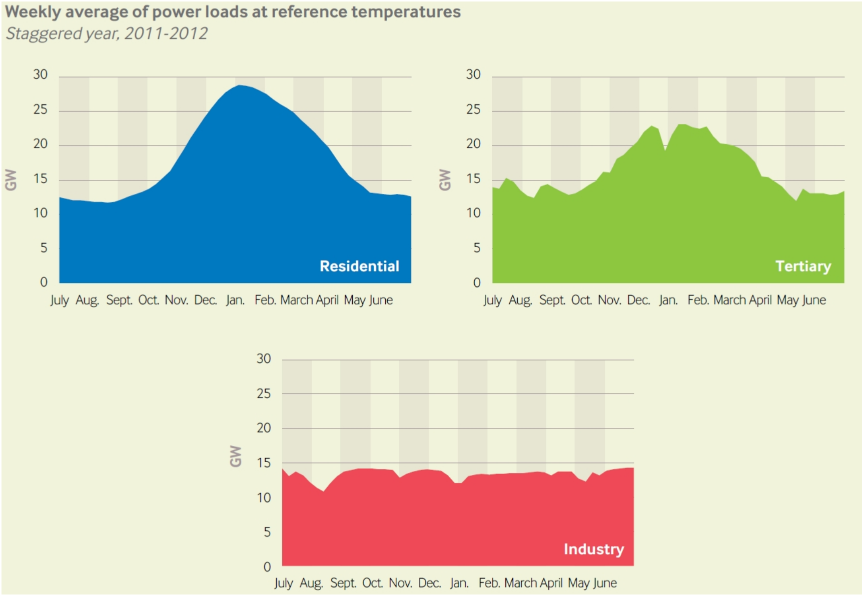
Source: BMWi (2015a).

The Federal Network Agency of Germany (*Bundesnetzagentur*) estimates yearly the need for grid reserve plants based on a system analysis and an analysis of how much can be acquired from power plants active in the power market. In its decision May 2015, it estimated that the future need for grid reserves is roughly 7 GW annually for the period 2015–17 after which it falls to 1.6 GW in 2019/20.[33] The drop in 2019/20 is based on the assumption that the common German-Austrian bidding zone will be divided in one German and one Austrian bidding zone. The estimated grid reserve need is increased to 6,100 MW for 2019/20 if there will still be a common German-Austrian bidding zone. The maximum need for redispatch 2019/2020 was calculated to 25,300 MW if there is a common German-Austrian bidding zone and 16,700 MW if there is a split of the bidding zone.

[33] BnetzA (2015).

3.3 France

Figure 11: Sectoral load curves in France



Source: RTE (2014a).

3.3.1 Background

Peak-loads in France coincide with cold weather due to a high share of electricity-based heating (cf. Figure 11). For this reason, and because the share of intermittent generation capacity in the French energy system is relatively low, the main national security of supply issue in France concerns the availability of capacity during hours of peak demand in winter.[34] To ensure an adequate supply, France introduced a capacity mechanism in the shape of a decentralized capacity market in its recent reform of the electricity market, initiated with the NOME Act of December 2010.

In addition to the expected national security of supply issues, which the capacity market aims to tackle, regional security of supply issues in Brittany

[34] RTE (2014b).

and The Provence - Alps – Côte D'Azur (PACA) region are emphasized as critical by RTE, the French TSO.[35] In Brittany, the issue concerns inadequate regional supply.[36] In the PACA region, the issue concerns a fragile regional power grid.[37]

3.3.2 The French capacity market

The French capacity market obliges electricity suppliers to hold capacity certificates corresponding to their contribution to the risk of a capacity shortfall as if every year faced a 10-year winter. If electricity suppliers fail to meet their obligation, penalties are imposed.

When the capacity market is fully functional, the delivery year will correspond to a regular calendar year. The first delivery year is 2017.

3.3.3 The capacity obligation

Capacity obligations constitute the demand in the French capacity market. The obligation requires obligated parties, mainly electricity suppliers, to contribute to security of supply relative to their contribution to the risk of a capacity shortfall in a 10-year winter; the shortfall risk.

The contribution of obligated parties to the risk of a capacity shortfall is calculated after the delivery year. However, the parameters used to calculate the size of the obligation are announced by RTE – the French TSO – prior to the delivery year (cf. Box 7). This allows obligated parties to take appropriate action to minimize the size of their obligation – and therefore the expenditures required to purchase certificates – in a cost-efficient way.[38]

Box 7: How the Capacity Obligation is Calculated

Parties with capacity obligations include: 1) electricity suppliers; 2) end consumers not (or only partially) supplied by electricity suppliers; 3) system operators, for their losses, when they are not supplied by electricity suppliers.

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[35] RTE (2011).
[36] To resolve the Brittany issue, the French Regulatory Commission of Energy held a tender for a 450 MW CCGT plant in Brittany in 2011. The tender was won by Direct-Energie and Siemens. It is currently delayed.
[37] The EU Commission recently opened two separate state aid investigations into the French capacity mechanism and the CCGT plant tender (EU, 2015a).
[38] RTE (2014b).

For each obligated party, the capacity obligation is calculated on the basis of observed consumption during system stress periods after taking into account three adjustments:

- Activated (and certified) demand response during peak periods.
  - This factor is added to observed consumption in order to avoid double counting of demand side response capacities (these capacities already benefit from having been issued capacity certificates).
- The temperature sensitivity of consumption.
  - This factor translates observed consumption into an estimate of what the consumption would have been if the temperature had corresponded to a one-in-ten year cold spell.
- A security factor.
  - Through this factor, the contribution to security of supply from interconnections and residual risks (other than temperature sensitivity) is taken into account. It reduces the obligation, and is currently set at 0.93.

Source: RTE (2014b).

3.3.4 The capacity certificate

Capacity certificates[39] constitute the supply in the French capacity market. In advance of the delivery year, certificates are issued to capacity operators (generation, storage, demand side response) relative to their contribution to reducing the shortfall risk.

There are different certification procedures for controllable and intermittent generation capacities. In addition to this, the certification process takes place at different times ahead of the delivery year, depending on whether the capacity is classified as either existing (min. 3 years), planned or demand side response (min. 2 months for both).

For operators of controllable generation capacities, capacities are certified according to a two-step procedure; the generic approach. Ex ante, capacities are certified according to the operator's self-assessed availability estimates during winter periods that are critical from a system point

[39] Definition: "A capacity certificate is intangible personal property, fungible, negotiable and transferable, corresponding to a normative unit power value, created by the public transmission system operator and issued to a capacity operator after a capacity has been certified and valid for a given delivery year" (RTE, 2014; p. 162–3).

of view. Ex post, a verification process measures the effective availability of capacities during critical periods of system stress.

Between the time of initial certification and delivery, rebalancing is possible. Final imbalances – when the certified capacity of an operator does not match the effective capacity delivered during hours of system stress – are settled through a balancing settlement system.

For operators of intermittent capacities (e.g. wind, solar PV, hydro run-of-river), capacities can be certified either on the basis of the generic approach – presented above – or a normative approach (cf. Box 8).

Box 8: The Normative Approach to certification of intermittent technologies

In the French capacity market, the contribution to security of supply from intermittent capacities, that choose to be certified according to the normative approach, is estimated through a combination of contribution coefficients (CCs), that reflect the average security of supply contribution of a specific technology, and the energy produced at peak hours historically for the respective technologies.

Certified Capacity Level = Historic Energy Production at Peak x CCtechnology.

The CC-value is calculated by RTE, and takes into account, among other things, the share of intermittent capacities in the power system.

For the first delivery years of the French capacity market, the following coefficients are applied:

- CC_hydro=85%
- CC_wind=70%
- CC_solar=25%

Source: RTE (2014b).

Participation in the certification procedure is mandatory for all capacities connected to public grids. This is a necessary condition for a technology neutral mechanism. Currently, cross-border capacities are only taken into account implicitly (cf. Box 9).

Box 9: The French capacity market and cross-border capacities.

Cross-border capacities do not currently participate in the French capacity market, but RTE has proposed a roadmap to pave the way for explicit participation of cross-border capacities. The roadmap does not propose a final date, at which cross-border capacities can participate.

The contribution to security of supply from cross-border capacities is recognized implicitly, however, through the security factor which reduces the capacity obligation of obligated parties relative to the projected availability of electricity imports at peak hours.

Source: RTE (2014b).

3.3.5 Trading

Obligated parties can meet their obligation by holding a sufficient amount of certified physical capacity, or simply by holding capacity certificates which they can acquire either through bilateral trading, or through a central exchange platform which is yet to be created. All certificate transactions are registered in a capacity certificate register kept by RTE.

3.3.6 Expectations for the first delivery year

In 2017, which is the first delivery year for the French capacity market, RTE expects the capacity certificate level to be 93 GW. This level takes into account the positive contribution to security of supply from cross-border capacities. If cross-border capacities had not been available, the security of supply reliability standard of of 3 hours per year would have required a capacity certificate level of 99.7 GW. The ratio of the expected capacity certificate level, and the capacity level required had cross-border capacities not contributed to security of supply, equals the security factor.[40]

[40] RTE (2014b).

3.4 Italy

3.4.1 Background

In Italy, the last few years have seen decommissioning of power plants with conventional capacity in combination with inadequate investment plans for new capacity. Looking ten years ahead, the same development is expected to continue. This change in the Italian energy supply is the consequence of market uncertainties related to an increasing share of renewables with intermittent generation characteristics, uncertainty about future demand, and pricing signals in the electricity market which do not incentivize capacity operators to undertake investments in an adequate amount of new capacity. As a consequence, security of supply issues have come into focus in Italy, and it has been decided to introduce a capacity mechanism in the shape of a capacity market in order to incentivize operators to maintain or invest in new conventional capacity. The coming capacity market replaces an existing capacity mechanism; a targeted capacity payment introduced in 2003 in the wake of a series of black outs.[41]

3.4.2 The Italian Capacity Market[42]

The new Italian capacity mechanism consists of a centralized capacity market in which reliability options are auctioned off to eligible auction participants. The capacity market product – the reliability option – is a contract-for-difference. This contract contains a capacity payment to successful auction participants, which in turn agree to two conditions. Firstly, the contracted capacity must bid into either the day-ahead market or the ancillary services markets (Dispatch Services Market, DSM). Secondly, operators of contracted capacity agree to pay back the difference between a contractually foreseen spot-market price and a pre-defined contractual "strike-price", whenever this difference is positive.

While the "strike-price" is set such that it corresponds to the standard, hourly variable costs of the marginal technology, i.e. an efficient peak plant,[43] the contractually foreseen "spot-price" is contingent on which market the contracted capacity bids into; or if it bids at all.

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[41] AEEG (2015).

[42] The Italian Ministry of Economic Development approved the Italian capacity market in June 2014. The initial aim was to hold the first auctions (with delivery period in 2017) in 2015 through what is known as the capacity market "implementation phase". At the time of writing (2016/2), the most recent information stem from ACER (2015). According to ACER, the first auction will be held ultimo 2016 with delivery in 2021.

[43] AEEG (2015).

The figure below presents the bid-dependent "spot-price" which is used to calculate the potential pay-back to Terna from capacity operators:

- When the bid of the contracted capacity is accepted on the day ahead-market (DAM), the "spot-price" is simply the market price.
- If the bid of the contracted capacity is *not* accepted on either market (DAM/DSM) the "spot-price" depends on system adequacy during that hour. In case of system adequacy, the "spot-price" equals the largest of either the DAM-price or the maximum price on the DSM, which is structured as a pay-as-bid market. In case of system inadequacy, the price equals the value of lost load (VoLL; VENF or *Valore dell'Energia Non Fornita* in Italian), which is currently 3,000 EUR/MWh.[44]
- If the contracted capacity is accepted on the DSM, the "spot-price" equals the contractual strike-price, unless the offered price in the DSM exceeds the "strike-price". In this case the "spot-price" is set to equal the offered price. In turn, this presents an incentive for the contracted capacity to never bid into the DSM at a price exceeding the "strike-price". If it does, it has to pay back the gain.
- If the contracted capacity is presented, but not accepted on the DSM, the "spot-price" equals the largest of either the DAM-price or the maximum price on the DSM.

The main consequence of this mechanism design for contracted capacity is two-fold. Firstly, it now does not pay off to bid above the strike price in the day ahead market, or in the ancillary services market. Secondly, the non-provision of capacity comes at a potentially extreme cost near the value of lost load (3,000 EUR/MWh).

Figure 12: The bid-dependent "spot-price" embedded in the reliability option

<table>
<tr><th colspan="2" rowspan="2">Quantity</th><th colspan="2">Spot price</th></tr>
<tr><th>Offered price ≤ strike price</th><th>Offered price > strike price</th></tr>
<tr><td colspan="2">Accepted on the Day-ahead market</td><td colspan="2">Price on the Day-ahead market (P_DAM)</td></tr>
<tr><td rowspan="2">Presented but not accepted on the Day-ahead market (DAM) and not presented on the Dispatch Sevices Market (DSM)
or
Not presented on the DAM nor on the DSM</td><td>Adequacy system</td><td colspan="2">Max (P_DAM; Max Price on the DSM)</td></tr>
<tr><td>Lack of adequacy system</td><td colspan="2">VENF</td></tr>
<tr><td colspan="2">Presented and accepted on the DSM</td><td rowspan="2">Strike price</td><td>Offered price</td></tr>
<tr><td colspan="2">Presented but not accepted on the DSM</td><td>Max (P_DAM; Max Price on the DSM)</td></tr>
</table>

Source: Terna (2015).

[44] AEEG (2015).

In practice, the high penalties for failure to provide at critical system hours essentially imply that the Italian capacity mechanism constitute both a financial and a physical obligation.

3.4.3 Capacity market demand

The demand in the market is determined annually on a regional basis by Terna. The regional aspect is included to take into account the fact that the Italian electricity grid is troubled by regional congestion issues. Instead of defining just one demand point, Terna defines a demand curve for each region as a function of the value of lost load (VoLL),[45] the loss of load probability (LoLP) related to each level of installed capacity, and the variable costs of the marginal technology.[46] In this sense, the Italian capacity market does not incorporate the Expected Loss of Load (LoLE) as a reliability standard measure, such as in the UK and France.

3.4.4 Capacity market supply

The supply in the market is determined by the portfolio offers – price and quantity combinations – of operators of generation and demand side capacities. Auction participation is voluntary, but eligibility is subject to the presentation of financial guarantees to Terna. Both new and existing capacities are eligible to participate, but certain capacity types are not, including: capacities with intermittent generation characteristics; capacities subject to any type of an incentive scheme; and capacities subject to an authority-approved dismantling measure.

Plans to include both DSR and interconnector capacities exist, although details on the conditions hereof are not yet in place.[47] Capacity that is either ineligible to participate or not offered for the capacity market is considered to bid into the market at a zero price (EUR 0/MW/year), and is ineligible for remuneration. The zero-bids reduce the clearing price of the capacity market resulting in a lower capacity payment.

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[45] Currently 3,000 EUR/MWh (AEEG, 2015).
[46] AEEG (2015).
[47] AEEG (2015).

3.4.5 The capacity payment

The capacity payment – entitled the "premium" and given as EUR /MW/year – is determined by the clearance price of the auction, as long as this price falls within a certain range defined by a price floor and a price cap. Both price limits are set by Terna. The price floor is implemented as the avoidable fixed operating and maintenance costs of an efficient CCGT plant, and the price cap is implemented based on estimates of the costs faced by a new entrant. While the aim of the former is to incentivize long-term investments by reducing the risk of a revenue shortfall, the aim of the latter is to limit the potential abuse of market power by big players in the capacity market.

3.4.6 The auction process

The auction process is structured as several auctions with different lead-times. The main auction is held four years prior to delivery, with a delivery period of three years. The relatively long lead-time of the main auction has been chosen to ensure that existing and new capacities are able to compete on equal terms. Between three and one years prior to delivery, annual adjustment auctions with a delivery period of one year are held with the purpose of: i) allowing the capacity operators to re-negotiate the contracted obligations; and ii) allowing Terna to adjust the adequacy target, and therefore the amount of capacity to procure, when new information becomes available as the delivery period approaches. In addition, a secondary market will be created to allow for continuous trading of the reliability option in the time between the auctions mentioned above and the delivery period.[48]

3.4.7 Financing

The Italian capacity market will be financed "through a charge levied on a monthly basis upon the dispatching users per energy withdrawal point (mainly retailers) and is collected by Terna".[49] We interpret this to mean that the costs of the capacity mechanism is smoothed on all consumers through a pro rate energy fee.

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48 AEEG (2015).
49 AEEG (2015).

3.5 Capacity mechanisms overview

Table 4: Capacity mechanisms overview

Features	UK	Germany	France	Italy
Core features				
Targeted or market wide	Market wide	Targeted	Market wide	Market-wide
Volume or price based	Volume	Volume	Volume[1]	Volume
Central or decentral	Central	Central	Decentral	Central
Reliability standard[2]	LoLE = 3h/y	None	LoLE = 3h/y	None
Is it technology neutral[3]	Yes	No	Yes	No
Physical/financial obligation	Physical	Physical	Physical	Both
Rules for activation	TSO call	TSO call Activated as a last resort.	TSO call.	Not relevant[4]
Supply features				
Does the mechanism remunerate technologies in receipt of other support measures	No	No	Yes	No
Is wind eligible for remuneration?	No[5]	No	Yes	No
Is solar eligible for remuneration?	No[5]	No	Yes	No
Are interconnectors eligible for remuneration?	Yes	No	No[6]	No[6]
Is storage eligible for remuneration	Yes	No	Yes	Yes
Demand features				
Does wind influence the capacity target of the mechanism?	Yes	No	Yes	Yes
Does solar influence the capacity target of the mechanism?	No	No	Yes	Yes
Do interconnectors influence the capacity target of the mechanism?	Yes	No	Yes	Yes
Does DSR influence the capacity target of the mechanism?	Yes	No	Yes	Yes

Features	UK	Germany	France	Italy
Other features				
Expected price effect: DA market	Negative	A small increase[7]	Negative	Negative
Financing principle[8]	Cost causality	Cost causality	Cost causality	Pro rata energy fee
Is there a mechanism end date?	No	No	No	No

Notes: 1) There is no centrally determined volume target in the French capacity market. However, the mechanism does contain a volume based element through the decentralized certificate purchases of French electricity suppliers.
2) In Germany, annual estimates of capacity margins are reported, but there is no centrally determined reliability standard target (Energinet.dk, 2015a). In Italy, they take a different approach to measuring system adequacy; see country description.
3) Whether the four capacity mechanisms are technology neutral or not is a difficult question. In the case of the UK capacity market, the European Commission (EU, 2014) has approved the mechanism design as technology neutral. This is, however, currently being challenged in the Court of the European Union by providers of UK DSR capacity who believe that the UK capacity market design favors new-built capacity over DSR (EU, 2015b). In the case of Germany, the capacity reserve is not technology neutral due to the inclusion of a lignite-based “climate reserve”, and because it does not allow new capacity to participate. In the case of France, the certification of all capacities indicates a technology neutral market. The French mechanism design is, however, very complex, and it is outside the scope of this analysis to evaluate whether all capacities compete on de-facto equal terms. In the case of Italy, the exclusion of intermittent capacities makes the mechanism non-neutral.
4) See country description.
5) While the UK capacity market currently excludes any capacity subject to other support measures (e.g. wind and solar PV), wind capacities are eligible to participate if (or when) no other support is received. Whether the same holds for solar PV is unclear.
6) Intentions to include cross-border capacities – in some way or the other – have been announced. No useful details are, however, publicly available at the time of writing.
7) This is under the assumption that capacities in the strategic reserve will not be decommissioned in any case. The White Paper only states that strategic reserve plants are likely to be commercially inoperable. If this is in fact the case, no price effect would be expected.
8) By cost causality we mean to imply that capacity mechanism costs are allocated to consumers in proportion to their contribution to the need for the mechanism.

4. Impact to the Nordic market of capacity mechanisms in four selected countries

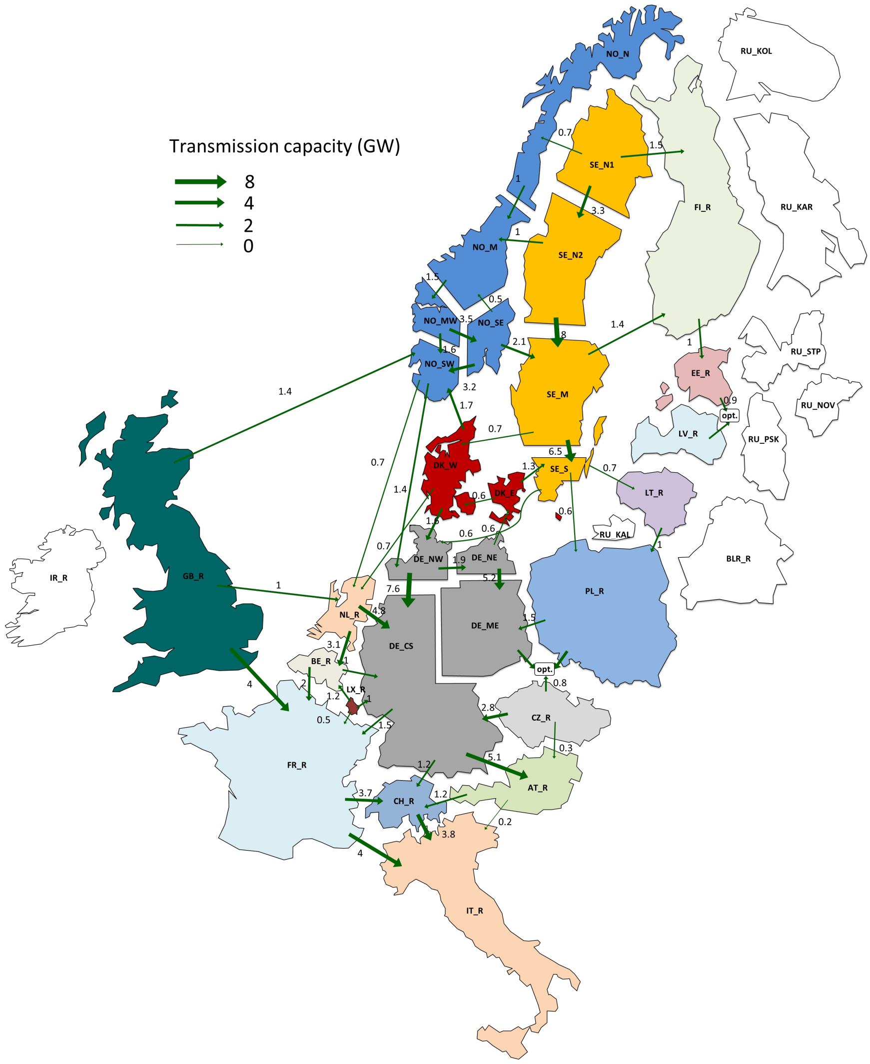
The aim of the scenario modelling in this report is to identify effects on the Nordic power system by introducing Capacity Remuneration Mechanisms in selected European countries. In the analysis, the following main assumptions and parameters are essential:

- Analysing market structure and existing capacity balances in relevant countries in a reference scenario. The reference scenario is in essence in compliance with the EU Target Model. Energy Only Market (EOM).
- Assumptions regarding decided, planned and future investments and decomissionings in production capacities of all types.
- Assumptions regarding flexibility in demand.
- Interpretation of how the capacity mechanisms in adjacent markets will influence both the local markets and the Nordic countries.

4.1 Model based analysis

The scenario analysis is carried out using a model-based approach. Our electricity market model (Balmorel) is used to model investments and generation dispatch in each node of an interconnected system representing a large part of Europe (cf. Figure 13). When the model invests in new generation capacity and decommissions existing capacities it is based on a least cost approach and assumptions regarding the required return on investments.

Figur 13: Geographical representation of all countries included in the simulation and interconnectors in the year 2020



Note: White regions are not included in the simulation.

The model is based on a relatively detailed technical representation of the existing power system; power and heat generation facilities as well as the main grid capacities. The main result is a least cost optimisation of the production pattern of all power units, assuming full foresight within one year on important factors, such as the development of demand, availability of power plants and transmission lines as well as generation patterns of renewable energy. The least cost optimization takes into account fuel costs, transmission costs, fuel and emission taxes, operation and maintenance cost.

Determining the effects of implementing capacity mechanisms When determining the effect of introducing capacity mechanisms, it is important to compare results with a reasonable reference. The years 2020 and 2030 are chosen as modelling years in order to represent both the near future and a longer time horizon.

It is important to note that the model will always secure just enough commercial capacity to balance the market in peak condition. However, the model will not allow prices to exceed the Nordpool price cap of 3,000 EUR /MWh. If higher prices are necessary in order attract marginal peak-load investment (or in order to keep older plants with high fixed costs in the market), the model will perform load-shedding.

4.2 Scenarios

4.2.1 Three scenarios are defined and analysed

Reference scenario
The first scenario is the reference scenario. Its main assumption is that of an EOM in all countries[50] in addition to general, country-specific assumptions about demand development, transmission expansions, thermal and RE generation capacity, fuel and carbon prices etc. With few exceptions, input data is based on publicly available sources (see appendix 2 for more details).

SR Germany scenario
The second scenario is similar to the reference, with the only exception being the introduction of a strategic reserve in Germany. Details of the model implementation are presented below.

CM scenario
The third scenario includes the planned (or current) capacity markets in France, Italy and the UK, in addition to the strategic reserve in Germany.

Details of the model implementation are presented below.

In order to implement the respective capacity mechanisms in the Balmorel model, it is necessary to define the mechanism volume for each model year, the types of capacity which are eligible to participate, and a contribution factor for each capacity type. The contribution factor is

[50] In a normal year the Nordic strategic reserves should not influence the results.

meant to reflect the fact that different capacity types contribute heterogeneously to security of supply. This latter aspect is part of the actual capacity mechanisms through e.g. the derating factors of the pre-qualification process in the UK mechanism and the certification process in the French mechanism (cf. Chapter 3).

With these definitions in place, the model enters capacity into the mechanism until the mechanism's volume restriction is upheld.[51]

4.2.2 The German strategic reserve

A 4 GW strategic reserve is implemented in Germany in 2020 and 2030, aligning with the current volume expectation of the White Paper (cf. section 3.2).[52] As the strategic reserve is to consist of "technically suitable power plants", the model has only been allowed to include thermal and hydro reservoir technologies in the reserve.

The 2.7 GW temporary lignite reserve (cf. section 3.2) – roughly two thirds of the full reserve – is implemented in the model for 2020, but not for 2030. This aligns with the expectations of the White Paper, and implies two post-2020 options for the plants in the lignite reserve: as they cannot reenter the EOM they either remain in the reserve or face decommissioning, depending on the least cost solution. The size of the aggregate reserve remains the same (4 GW).

Capacity entered into the capacity reserve does not participate in the EOM of the Balmorel model.

4.2.3 Capacity markets

Three capacity markets are implemented in the model for the CM scenario. Details of the respective markets are mainly based on the market descriptions in Chapter 3, but also to some extent on chosen assumptions in cases where explicit public information has not been available. The following section describes the model implementation for each country.

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[51] Using the contribution factor for every generation type the model calculates the contribution to the capacity markets for all existing and planned generation capacities that are included in the model assumptions. Through a least-cost optimization the model then fulfills the capacity market requirements (together with potential other national policies on capacities) by the installed generation capacity and investments in new generation capacity. The model also decommissions existing capacity that is no longer economically viable, thus creating a higher need for new capacity.

[52] The actual expectation is 5% of anticipated average annual peak load, or 4 GW currently. As German demand is expected to remain steady towards 2030 (cf. section 4.1), this analysis maintains this reserve volume for both 2020 and 2030.

France

In France, the main power adequacy issue as one of peak demand during cold winters. For this reason, the French capacity market has been designed to ensure capacity adequacy as if every year faced a cold 1-in-10 year winter.

The only publicly available assumption about the volume of the French capacity market stem from RTE, the French TSO, which estimates the expected capacity market volume for the year 2017 to be 92 GW.[53] This number is derived after taking the "security factor" into account – the contribution from interconnected capacity (cf. section 3.3). Furthermore, it is an estimate of the actually available capacity, often termed derated capacity. In 2017, peak load is estimated at roughly 85 GW if it is a normal winter.[54]

With the above information is mind, this analysis has implemented a capacity market volume of 105% of normal-year peak load in France for both 2020 and 2030.[55] In terms of the model setup, this implies that investments will be undertaken such that derated capacity in the model – that which is actually available during peak loads – equals 105% of modelled peak load.

The 105% ratio can be considered a conservative estimate, where the following line of argumentation applies:

- The estimated market volume for 2017 (92 GW) is about 8% larger than estimated peak load if the winter is normal (a normal year).
- The capacity volume estimate of 92 GW in 2017, however, is based on a contribution from interconnected capacity in times of system stress corresponding to 7% the "security factor". This factor is likely to increase considerably in the modelled years 2020 and 2030 and reduce the volume of the capacity market, because the maximum French import capacity increases considerably after 2017. In fact, RTE estimates that interconnector capacity will increase by 40% from 8.9 GW in 2015 to 12.4 GW in 2019.[56]

In the modelling, it has been taken into account that different capacity types participate on different terms in the capacity market (cf. section 3.3). The reason is that one unit (thermal/storage/RE) of capacity will not contribute

[53] RTE (2014b).

[54] RTE (2014a,b). The two sources present estimates based on different underlying assumptions.

[55] The Balmorel model simulates normal-years, where historical load profiles are scaled according to the expected future annual demand. It should be noted that the use of historical profiles provide reasonable estimates of peak demand, without implying that the actual (future) peak demand will be the same.

[56] RTE (2014a).

to security of supply with the full installed capacity. Uncertainty in form of outages, water flows, wind speeds, etc. limits the amount of capacity each unit can reliably bring to the market. The metric which describes this aspect is called the contribution factors in the following.

Contribution factors for certified capacity are based on RTE-expectations for certified capacity in 2017:[57]

- 90% for thermal and hydro with reservoir.
- 5.3% for solar.
- 37% for hydro run of river.
- 20% for wind.[58]

Since the contribution factor falls short of 100% for all generation types, the model outcome in terms of nominal capacity will exceed 105% of modelled peak load.

United Kingdom

In the UK, the capacity market volume is determined through a rigorous process (cf. section 3.1). The system operator, National Grid, provides annual recommendations about the level of derated capacity required to meet the security of supply reliability standard.

In this analysis, the UK capacity market is implemented similarly to the French capacity market described above. While the two mechanisms might be different in terms of design (e.g. one is a central mechanism while the other is decentral), the expected outcome is the same. The mechanisms remunerate capacity installations, and increase the national capacity volume. In addition, they are designed to ensure the availability of capacity during system stress situations, mainly peak loads. One important difference, however, concerns capacities in receipt of other subsidies. While these capacities are remunerated in the French mechanism, this is not the case in the UK.

Public information about the expected level of the capacity market volume and the expected peak load is available for most of the studied period: National Grid provides estimates for the period 2020–2029 in their Electricity Capacity Report 2015.

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[57] RTE (2014b).

[58] In Chapter 3, the definition of the certified capacity level for wind was presented as: Certified Capacity Level = Historic Energy Production at Peak x CCwind, where CCwind = 70%. The 20% contribution factor given here therefore implies that RTE has estimated the historic production of wind (relative to capacity) during peak hours at roughly 30%.

However, National Grid does not deliver just one estimate of the future capacity market volume and the expected peak load. Instead, several estimates are provided based on different scenario analyses. As neither of the National Grid scenario assumptions align perfectly with the assumptions used in Balmorel, which falls somewhere in between for most parameters, this analysis has maintained the best estimate of Ea Energy Analyses of peak load for a normal-year.

With this being the point of departure, the UK capacity market volume has been modelled as a mark-up over Balmorel peak demand, where the mark up is given as the ratio between National Grid's estimates for peak demand and the capacity market volume, respectively. This ratio is 89% in 2020 and 79% in 2030.[59] These ratios are lower than for France mainly because wind in the UK reduces the capacity market volume requirement without being eligible for remuneration. The drop from 2020 to 2030 is caused by a considerable roll-out of wind turbines, which is a factor outside the capacity market that contributes to security of supply.

Modelled contribution factors for the UK are:[60]

- 90% for non-RE thermal and hydro reservoir technologies.
- 0% for RE technologies (including thermal) and new-built nuclear.

Italy

Little is known about the official expectations for the Italian capacity mechanism in terms of both volume and mechanism dynamics. Due to this lack of information, this analysis has taken a simplified modelling approach, and implemented the Italian capacity market similarly to the French capacity market. The rationale for this approach is that the net effect in terms of additional capacity will be similar.

Following this, the Italian capacity market volume has been proxied through the model requirement that the derated capacity must fulfill at least 105% of modelled normal-year peak demand. Italian contribution factors have also been proxied through the French equivalents:

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[59] National Grid (2015a) estimates vary across the 4 scenarios that they use in their analyses. In this analyses, average estimates from the Gone Green Scenario and the Consumer Power scenario has been used, because the underlying scenario assumptions (on e.g. the future generation mix) resemble the underlying assumptions in Balmorel best. As National Grid estimates only go to 2029, this year has been used to proxy 2030.

[60] Based on National Grid (2015a).

- 90% for thermal and hydro reservoir technologies.
- 5.3% for solar.
- 37% for hydro run of river.
- 20% for wind.

4.3 Main model input data

This section presents the main input data including Nordic capacity balances, demand development (annual and peak) and fuel prices. Other input data is presented in Appendix 2.

4.3.1 Capacity balance in the Nordic countries in 2014

For 2014, the base year of the model simulations, capacity data from a broad range of data sources is fed into the Balmorel model database. The table below presents these capacities aggregated by main fuel type, and includes similar and recent data from ENTSO-E for comparison.

Table 5: 2014 capacity comparison. Balmorel data and ENTSO-E data (in brackets)

	Denmark	Finland	Norway	Sweden
Nuclear	0 (0)	2.8 (2.8)	0 (0)	9.6 (9.9)
Fossil fuels	5.4 (4.7)	8.8* (9.3)	1.0 (1.2)	5.2 (5.9)
– Gas	2.1 (2.2)	1.8 (1.9)	0.7 (1.2)	0.8 (0.9)
– Coal	2.2 (2.4)	3.4 (3.6)	0 (0)	0.4 (0.2)
– Oil	1.1 (0.1)	1.7 (1.7)	0.3 (0.0)	3.8 (4.6)
Hydro	0 (0)	3.1 (3.2)	31.1 (31.0)	16.2 (16.2)
RE	6.4 (6.8)	2.4 (2.5)	0.8 (0.8)	7.2 (7.2)
– Wind	4.8 (4.8)	0.4 (0.5)	0.8 (0.8)	4.5 (4.0)
Total	12.1 (11.4)	17.6 (17.7)	33.0 (33.0)	38.6 (39.2)

Note: The data shown from the ENTSO-E source is an estimate for a day in January at 19:00 pm. ENTSO-E uses two scenarios. A conservative estimate and a "best guess". Here, data is presented from the latter. * Including peat capacity.

Source ENTSO-E Scenario Outlook & Adequacy Forecast (SO&AF) 2014.

A few inconsistencies exist between the Balmorel data set, and the ENTSO-E data.

For Denmark, the data used in the model analysis here has a surplus of oil capacity compared to the ENTSO-E data. The surplus is about 1 GW. This is probably caused by differences in the definition of system reserves. Under any circumstance, the differences regarding oil capacities will not affect the model results for 2020 and 2030, as the model will decommission all capacities that are not commercially viable in the electricity and district heating markets.

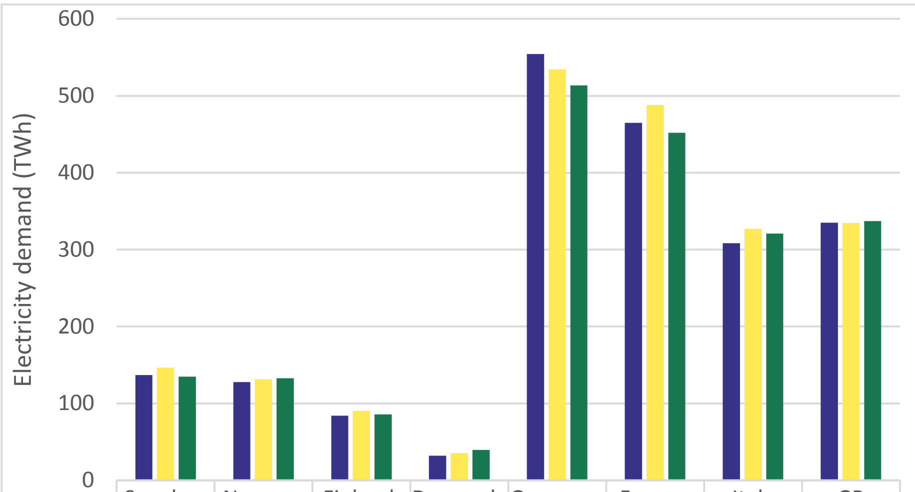
For Norway and Finland, the capacity data align well.

For Sweden, there is a small data discrepancy, which is mainly caused by a lower inclusion of oil capacities, and a slightly higher inclusion of wind capacity. It can be noted, that the ENTSO-E data presented above is from ENTSO-E's Scenario B, which is a best "guess scenario". ENTSO-E's Scenario A, which is a "conservative scenario" (not shown here), has 38.3 GW total capacity in Sweden. This is a slightly lower aggregate capacity estimate compared to the data used in the model analysis here.

4.3.2 Electricity demand

Electricity demand projections for selected countries are presented below.

Figure 14: Annual electricity demands (TWh) for the years 2014, 2020 and 2030



	Sweden	Norway	Finland	Denmark	Germany	France	Italy	GB
2014	136,7	127,8	84,0	32,1	554,3	465,1	308,4	335,1
2020	146,3	131,5	90,2	35,3	534,6	488,3	327,3	334,7
2030	134,8	132,6	85,8	39,4	513,7	452,0	320,8	337,2

Source: 2014 data is from a mix of publicly available national and EU sources. Projections for 2020 and 2030 are based on Energinet.dk's public 2015 analyses assumptions for Denmark, and outside Denmark ENTSO-E's Ten Year Network Development Plan 2016; average of Vision 2 and 3.

4.3.3 Peak loads

Peak loads are assumed to grow slightly from 2020 to 2030 for Denmark and Norway, while there is no significant change for Finland and Sweden, cf. Table 5. Peak load developments reflect to a large extent the development in annual electricity demands.

These peak load assumptions are slightly higher than comparable ENTSO-E estimates, from the most recent Scenario Outlook & Adequacy Forecast report, shown in brackets in Table 5.

The ENTSO-E load forecasts are based on "best national estimate available to the TSOs, under normal climatic conditions, taking into account the highest expected growth of the consumption according to national grid development plans".

Table 6: Modelled peak loads (GW). ENTSO-E estimates in brackets

	Denmark	Finland	Norway	Sweden
2020	6.2 (5.9)	14.4 (14.1)	24.6 (23.0)	26.3 (23.0)
2030	6.9 (6.3)	13.7 (14.9)	24.8 (24.0)	24.3 (23.1)

Note: Note 1: ENTSO-E uses two scenarios; a conservative estimate and a "best guess". Here, data is presented from the latter.
Note 2: In the 2030 comparison, ENTSO-E estimates are for 2025 due to lacking 2030 estimates

Source: ENTSO-E Scenario Outlook & Adequacy Forecast (SO&AF) 2015

4.4 Main results

The results of the scenarios are presented in terms of annual average electricity prices, peak electricity prices, and capacity balances in the following section for the two model years 2020 and 2030.

4.4.1 Average electricity prices

It is to be expected that the average electricity prices will increase in the SR_Germany scenario compared to the reference and again decrease in the CM scenario. The reason for this is that in the SR_Germany scenario capacity is removed from the market, whereas the capacity markets will secure that existing and new capacity is partly financed through the capacity remuneration schemes outside the EOM market, thus removing the price spikes.

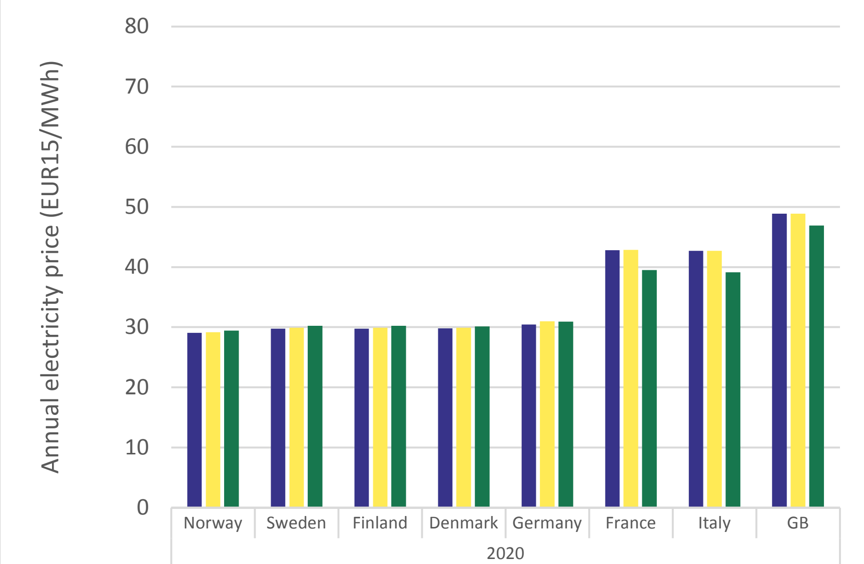
First of all, the resulting average prices for 2020 are substantially higher than futures prices for year 2020[61] quoted February 9 2016 (EUR 18.05). The main reason for this probably lies in the fact that the model has been allowed to create the long-term market balance already in 2020. This means, that all power plants that are not viable in the market are decommissioned, and the model even invests in some new viable plants. In reality such a dramatic change in infrastructure is not realistic in only five years time. Therefore the futures price of EUR 18.05 probably represent a market that is not in long term balance due to excess capacity from a market perspective.

The average prices in the Nordic countries are similar in all three scenarios (cf. Figure 15). Denmark has the strongest connections to the adjacent markets (compared to national consumption) and is most affected by the changes in those countries.

SR Germany

Prices in the Nordic countries are marginally higher in the SR_Germany scenario. This indicates that some of the German strategic reserve is in fact in commercial operation in average years in the reference.

Figure 15: Average annual electricity price (EUR 15/MWh) for the year 2020



	Norway	Sweden	Finland	Denmark	Germany	France	Italy	GB
Reference	29,0	29,8	29,8	29,8	30,4	42,8	42,7	48,9
SR_Germany	29,2	29,9	29,9	29,9	31,0	42,8	42,7	48,9
CM	29,5	30,3	30,2	30,2	31,0	39,5	39,2	46,9

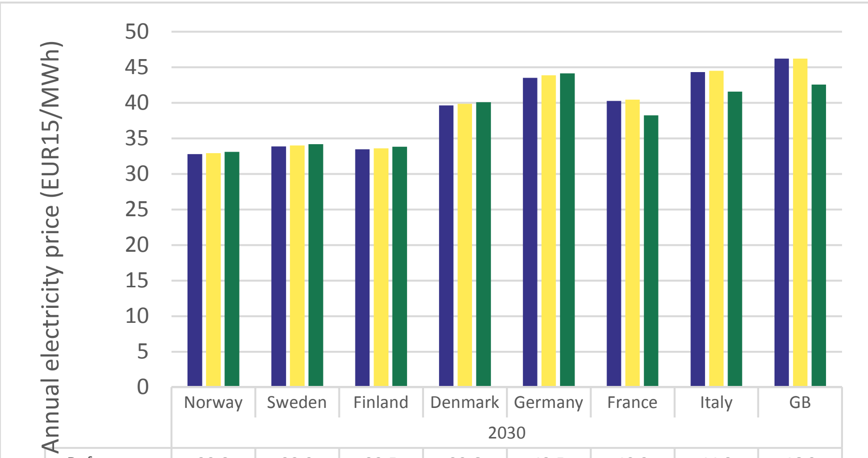
[61] http://www.nasdaqomx.com/commodities/market-prices

CM Scenario

The CM scenario shows a significant decrease in electricity prices in the relevant countries, France, Great Britain and Italy. The effect on Nordic electricity prices, however, is a slight upward push. This is somewhat surprising as the opposite effect was to be expected. We have not fully understood the reasons for the slight increase, but scrutiny of more detailed results point at an increased switch from coal to natural gas and other sources in the Nordic countries in the CM scenario. This is probably the explanation. See also Figure 19 where a duration curve for Finland is shown.

For 2030 the input fuel prices and CO_2 prices are based on the latest IEA projections from World Energy Outlook 2015. These prices are much higher than todays prices and push electricity prices upwards in all of Europe. Also the stronger connection between the Nordic countries and Great Britain (Viking cable) impacts on prices. However, apart from the general higher price level the overall picture is similar to that from the 2020 calculations.

Figure 16: Average annual electricity price (EUR15/MWh) for the year 2030



	Norway	Sweden	Finland	Denmark	Germany	France	Italy	GB
Reference	32,8	33,9	33,5	39,6	43,5	40,3	44,3	46,2
SR_Germany	32,9	34,0	33,6	39,9	43,9	40,5	44,5	46,2
CM	33,1	34,2	33,8	40,1	44,2	38,3	41,6	42,6

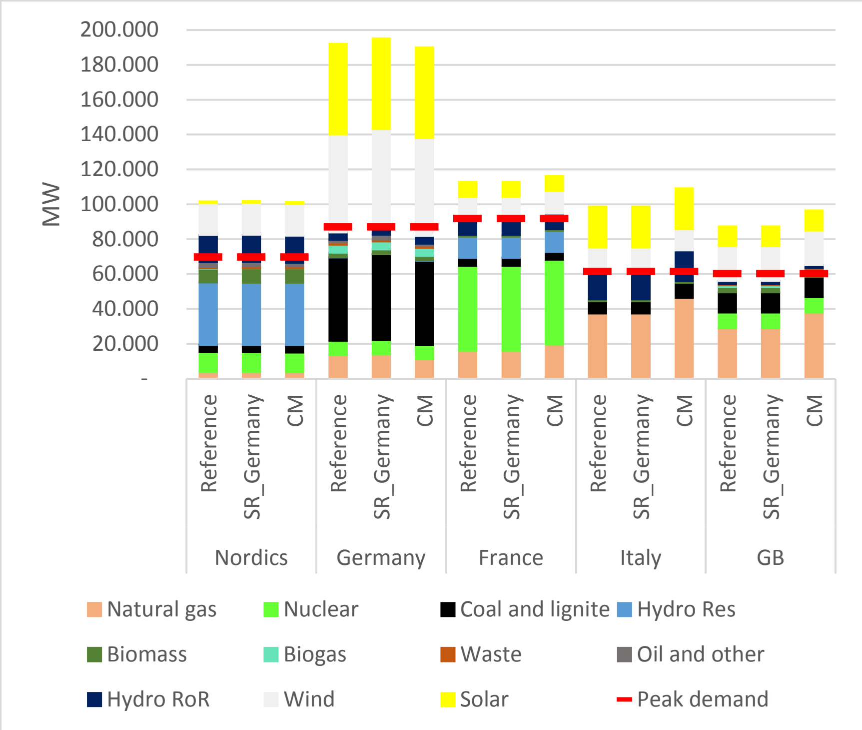
4.4.2 Capacity balances

In the figure below the modelled capacity balances in the Nordics and analysed adjacent countries can be seen (The capacity mechanisms will also affect other countries in the model area, but these countries are not shown in the figure).

It is quite clear from the figure, that the capacity markets in Great Britain, France and Italy increases capacity in these countries, and slightly reduces capacity in Germany. The effect on the Nordic countries is limited. Please note that the shown capacities reflects the market balance, and dos not include regulating reserves.

An other observation from the figure is that the contribution from fluctuating renewables is substantial, especially in Germany. The growth in renewables towards 2020 is mainly based on national sources. Please see appendix 2.

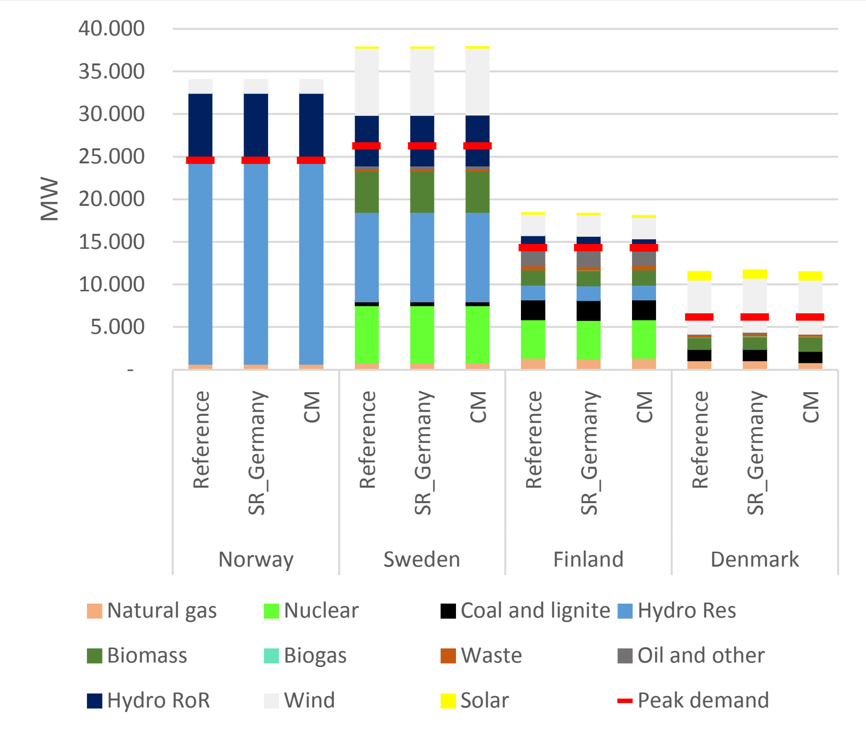
Figure 17: Total generation capacity and peak demand given in MW for the three scenarios in 2020



Note: The Nordic countries are grouped as one region.

In Figure 18 the modelled capacity balances for the Nordic countries in 2020 are shown. It can be seen, that the balances are quite unaffected by the capacity mechanisms on the continent.

Figure 18: Total generation capacity and peak demand given in MW in the Nordic countries for the three scenarios in 2020

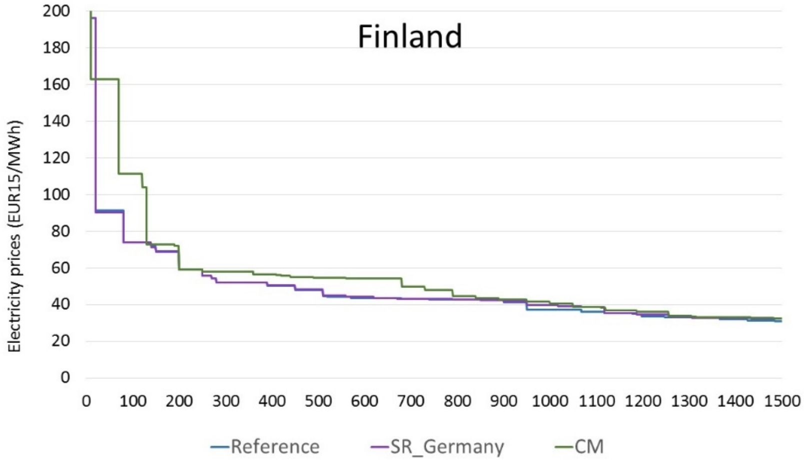


4.4.3 Peak electricity prices

It is important to note, that due to time constraints the investment runs are not carried out in full time resolution (8,760 time steps per year). In this project investment runs have been made with 320 annual time steps, and the results are hereafter converted to hourly values. The reduced time-resolution has the effect, that the price needed to cover long term marginal costs for the marginal units is lower. That is why the model never reaches the Nordpool price ceiling, but finds the needed "scarcity price" somewhat below.

The average national peak prices are illustrated for the 1,500 hours with highest prices in 2020 in the model simulations (10 highest peak prices are cut off). The pattern of the price duration curves in peak periods are quite similar in the Nordic countries. In the figure below Finland is shown as an example.

Figure 19: Electricity prices (EUR15/MWh) in 2020 for Finland in the 1,500 highest prices



Note: 10 highest peak prices lie beyond the chart area.

As was the case with average prices the differences between the scenarios is quite limited. It could be expected that the capacity markets in Great Britain, France and Italy would reduce investments in power plants in the Nordic area to an extent where scarcity would increase. In fact the investments are almost more than 500 MW lower in this scenario. In addition, some baseload is exchanged with peak load, altering the duration curve.

It is important to remember, however, that the model runs do not include strategic reserves or other capacity mechanisms in any of the Nordic countries.

5. Capacity adequacy in Nordic countries according to recent studies

A number of studies have been presented recently in the Nordic countries regarding capacity adequacy and/or challenges for the electricity system because of the ongoing integration of intermittent renewable production. This chapter presents a comprehensive description of the findings in these studies. The possible implications of both the Nordic peak load weeks 1–3 2016 and the falling forward prices on future capacity adequacy are also discussed. Finally, this chapter presents some conclusions regarding the need for capacity mechanisms in the Nordic countries.

5.1 Denmark

Three studies – published by Energinet.dk, the Danish Energy Agency and the Danish Energy Association – that have been presented on Danish capacity adequacy issues in 2015 alone are presented in this section.

5.1.1 Energinet.dk

In September 2015 the Danish TSO presented the conclusions of the "Markedsmodel 2.0" project. The purpose of this project was to analyse security of supply in an open process involving main stakeholders. The conclusions grouped around three subjects: capacity, flexibility and so-called critical properties.

5.1.2 Capacity

A continued high level of security of supply requires action. If the current electricity market is maintained, it implies an increased risk of power shortages, i.e. the amount of electricity generated or imported will not be sufficient to cover the electricity consumption in Eastern Denmark in periods characterised by several failures. This means that from around

2025, Eastern Denmark could be in shortage of electricity for longer periods of time than Energinet.dk has established as acceptable.[62] Therefore, the electricity market needs new mechanisms. Western Denmark is expected to be able to maintain Energinet.dk's security of supply target.

5.1.3 Flexibility

Wind and weather conditions change the electricity system. The electricity market lacks the necessary incentives to drive a development that ensures increased consumption of electricity when it is cheap, and less in periods with no wind and electricity is expensive. There is a need for greater demand side flexibility. Therefore, market rules are in need of reform, and the introduction of new business models are necessary for a well-functioning market.

5.1.4 Critical properties

Who supplies when the power stations are not operating? Some of the properties that are critical to operating the electricity system are currently supplied by the power stations. But power stations are operating less and less. This entails the need to find new ways to obtain and remunerate for critical properties.

5.1.5 The Danish Energy Agency

In July 2015 the Danish Energy Agency presented the report "Elforsyningssikkerhed I Danmark". In this report the results of a series of analyses with DEA's probabilistic model, Sisyfos, are shown.

Sisyfos calculates the frequency of the expected power shortages (Loss-of-load probability; LOLP) and expected energy not supplied (expected unserved energy; EUE).

Moreover, Sisyfos calculates the average power availability, import dependence, and a number of other key figures. The report underlines that calculations are uncertain, e.g. assumptions about future plant closures both in Denmark and abroad.

Central conclusions from this report include:

[62] The acceptable level is defined as a max shortage level of 20 minutes per year from a combination of capacity adequacy and transmission-system security. Of this, adequacy must not contribute with more than 5 minutes/year.

- The calculated capacity adequacy today is good, which is consistent with the fact that a lack of adequacy have not been recorded in recent times.
- The Danish electricity system undergoes a process where there will be more international connections, more fluctuating power and less thermal capacity. Therefore, the dependence on foreign capacity will increase over time. For this reason, it becomes increasingly essential to ensure the availability of interconnectors and of capacity in other countries.
- In the "National" calculation, adequacy is a challenge in Eastern Denmark throughout the calculation period. The frequency of power shortages will be significant by 2020. This is not the case in western Denmark.

The main results are shown below:

Table 7: Calculations of Loss of Load Probability (LOLP) and Expected Unserved Energy (EUE). Both indicaters shown as minutes/year

Minutes/year	2015	2020	2025
DK1	<–0.02	<–0.02	1.3/0.7
DK2	0.27/0.15	3.3/1.5	29/15

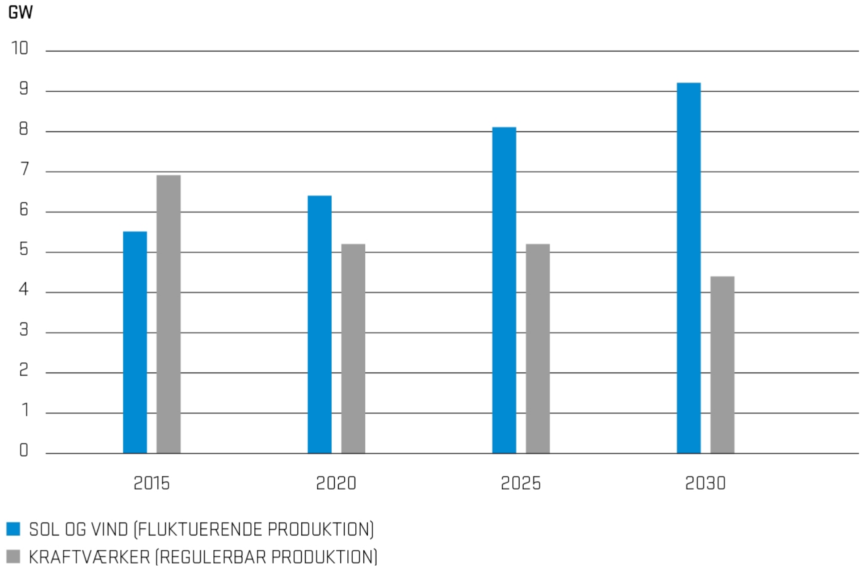
Source: Security of electricity supply in Denmark.

When comparing the above LOLP-minutes to the term LOLE as often used, the LOLE should be divided with app. 10 taking the Danish consumption pattern into account. Thus 3 hours LOLE is equal to approximately 20 LOLP-minutes.

5.1.6 The Danish Energy Association

The Danish Energy association published the report "Giv Energien Videre" in 2015. In the report, concerns regarding the development of electricity prices and consequently the Danish capacity balance are voiced. In compliance with both the reports of both Energinet.dk and the Danish Energy Agency, this report foresees a reduction of (thermal) capacity towards 2030. The strongest reduction is expected between 2015 and 2020.

Figure 20: Projection of the Danish Capacity balance towards 2030



Source: "Giv Energien Videre", Dansk Energi, 2015.

A general conclusion from the three recent Danish analyses is that security of electricity supply will increasingly depend on possible imports from neighbouring countries.

5.2 Finland

5.2.1 Current strategic reserve

Finland has a strategic reserve in order to secure the electricity supply during situations when market based electricity production can't cover consumption. The Finnish Energy Authority defines the reserve need. Plants are not allowed to be market-active as long as they are contracted.

The reserve volume was 600 MW in the period 2007–2013, and 365 MW in 2013–2015.

The Energy Authority ordered in 2014 a report from VTT regarding needed peak load reserve. VTT presented a second report February 2015 regarding the needed capacity if some condensing power plants will disappear from the market.

Two power plants and one demand side flexibility facility (10 MW) were chosen by the Energy Authority after public procurement for the period July 2015 – June 2017.[63] The total reserve volume is 299 MW during the two-year period at an annual cost of 7 million EUR. The Energy Authority will perform a new assessment of needed reserve capacity before the expiration of the current two-year period.

5.2.2 Fingrid forecast

Fingrid presented in November 2015 an analysis regarding capacity adequacy for the coming winter.[64] The forecast for peak electricity consumption was about the same as last winter, 15,000 MW. However, closures of Finnish power plants have further weakened the situation relative to previous years. The forecasted production ability (including the strategic reserve) was lowered to 11,600 MW, implying an increased need for electricity imports in the coming winter; the estimate is 3,400 MW on a very cold day. Fingrid notes that the needed import capacity is higher than the total nuclear capacity in Finland.

Fingrid estimated that transmission connections are sufficient to import the required electricity to Finland in the winter 2015–2016, and that electricity will be available in neighbouring countries. However, there is little room for faults in production plants and transmission connections, and the possibility of short-term restrictions on electricity consumption has increased. Fingrid reported that it is prepared for such a situation. Restrictions on electricity consumption would most likely apply to a small minority of electricity consumers and only up to a few hours. Electricity supply for functions important to society can also be secured in cases of an electricity shortage.

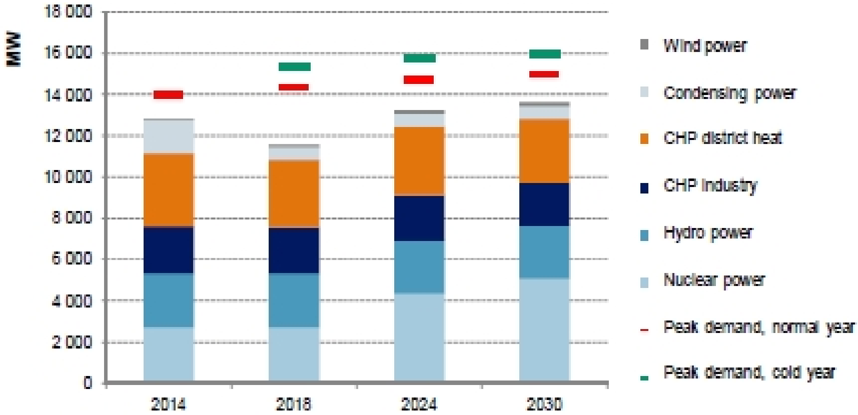
[63] http://www.energiavirasto.fi/en/web/energy-authority/strategic-reserve
[64] http://www.fingrid.fi/en/news/announcements/Pages%2FElectricity-shortage-is-possible-during-a-cold-winter.aspx

5.2.3 *Pöyry report*

Pöyry presented the report "Adequacy of power capacity in Finland and the development of capacity structure until 2030"[65,66] in January 2015.

In the report, the relationship between electricity production and consumption is estimated in the short term (until 2018), in the medium term (until 2025) and in the long term (until 2030). Three scenarios (Central, High and Low) based on various assumptions about economic, political and energy consumption development are analysed. Estimates in the report are based on Pöyry's views and analysis. The following figure shows the development of generation capacity and peak demand in the Central scenario.

Figure 21: Development of peak demand and generation capacity in the Central scenario



Source: Pöyry.

Finland's generation capacity does never cover peak demand during the studied period. On a more detailed level:

- The maximum gap occurs in 2018, where it reaches 2,800 MW in a normal year and 4,000 MW in a cold year.
- Condensing capacities decrease substantially already in the short term prior to 2018.
- Olkiluoto 3 (1,600 MW) is expected to be taken into operation by the end of 2018. A sixth reactor (1,200 MW) is assumed to enter into

[65] http://www.tem.fi/files/42026/Kapasiteetin_riittavyys_raportti_final.pdf. A summary in English is available on http://www.tem.fi/files/42541/Translation_Capacity_development_in_Finland.pdf
[66] Pöyry was assigned by the Ministry of Employment and the Economy, Finnish Energy Industries ET, Fingrid Oyj, Finnish Forest Industries Federation and Suomen ElFi Oy to prepare an evaluation of the adequacy of Finnish power generation capacity in both the short and long term.

operation in 2025. The two reactors in Loviisa (992 MW) are assumed to be closed in 2027 and 2030 after 50 years of operation.

- The development of peak demand, condensing and CHP capacities differs across the three scenarios while the remaining capacity types follow the same path.
- In the Low scenario, the capacity gap reaches 2,500 MW in 2018 in a normal year, and 3,700 MW in a cold year. In the High scenario, the equivalent gaps are 2,700 MW and 3,900 MW respectively.

With respect to import capacity from neighbouring countries, capacities currently range from 2,700 MW (Sweden), 1,400 MW (Russia), and 1,000 MW (Estonia). Pöyry assesses the available import capacity to be sufficient in situations of peak demand in Finland. The reason being that insufficiency of imported electricity will require several simultaneous fault situations and the occurrence of peak demands at the same time in nearby areas.

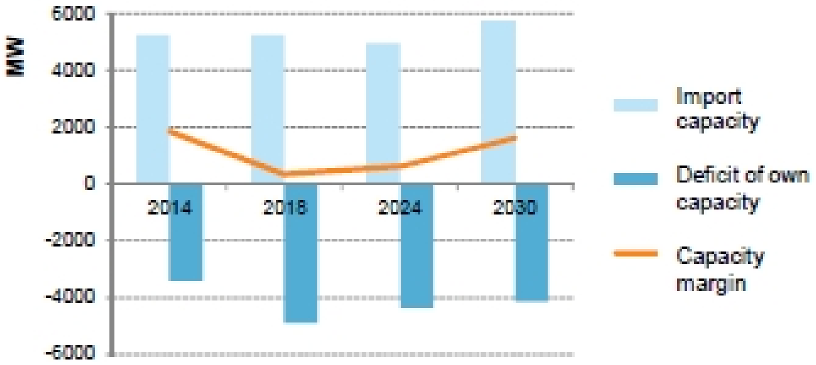
When Olkiluoto 3 enters into operation, Finland needs an increased disturbance reserve; a need that is planned to be partly covered by reservation of 300 MW of import capacity from Northern Sweden. As a consequence, the import capacity from Sweden is reduced to 2,400 MW.

Pöyry expects the interconnection to Sweden to be strengthened by 800 MW in 2025. In addition, Pöyry notes that many new interconnections are planned between the Nordic countries and neighbouring countries, and that this will strengthen the capacity situation in Sweden.

The conclusion in the report is that sufficient capacity exists in Finland, and that this conclusion holds across the three scenarios – even for a cold winter – as long as import capacity is taken into account. For this results not to hold, at least 1,200 MW of electricity generation or import capacity has to be unavailable in 2018. For the remaining periods of the study, the margin is higher.

The largest generation unit until 2018 is Olkiluoto 1 or 2 (880 MW). After 2018, Olkiluoto 3 (1,600 MW) is the largest unit. The following figure shows the capacity margin during a cold winter peak demand if the largest generation unit is inoperative but full import capacity is available. In 2018, the capacity margin falls short of 400 MW if the largest generation unit is inoperative.

Figure 22: Capacity margin during a cold winter peak demand when the largest generation unit is out of operation



Source: Pöyry.

In Pöyry's scenarios, current industrial demand-side response is taken into account in the peak demand calculations. Pöyry finds it possible to bring more demand-side response to the market, including smaller units when electricity pricing becomes increasingly hourly-based, and when there are more available products and services which can automatically steer the demand. These possibilities will take time to develop. In 2030, the scope for more demand side response is estimated at nearly 1,000 MW.

5.3 Norway

Norway normally has significant surplus capacity even in peak load situations. This was shown earlier this winter, where the new production record set in week 1 (26,766 MW) exceeded the new consumption record set in week 3 (24,485 MW). These two records are close to Statnett's forecasted Norwegian power balance in 2015–2016 for a cold winter day in 1 of 10 winters. Production capacity was estimated at 26,500 MW, and peak load at 24,500 MW.

The trade capacity for export from South Norway to Sweden (NO1 to SE3) is normally reduced from its maximum of 2,100 MW in cold situations. The day-ahead capacity for export from NO1 to SE3 was limited to 1,040 MW for the hour with the new Norwegian consumption record.

The grid structure in Norway is such that a transmission fault can result in a critical capacity situation in a part of the country. The availability of regulation resources located on the right side of a bottleneck are important for managing such situations.

Statnett has therefore created a market for regulation power options (RKOM) to secure that there are sufficient bids in the regulation market to manage disturbances. There are both seasonal and weekly purchases of RKOM. In the seasonal purchase for the winter of 2015–2016 521 MW of RKOM were acquired. Weekly purchases of RKOM are done in addition if Statnett's power situation forecast identifies such a need for the folllowing week.

Statnett also has four special tariffs for flexible demand connected to the central grid. These special tariffs involve a much lower capacity fee than the ordinary tariff. The size of the fee depends on the accepted disconnection time of consumption; 15 minutes, 2 hours or 12 hours. The fourth special tariff applies to demand which can be disconnected within 15 minutes, but has to be reconnected within 2 hours.

There are also Norwegian grid companies with special grid tariffs for flexible demand. The company with the largest number of grid customers, Hafslund Nett, has three special tariffs for flexible demand. One tariff is for consumers who accept to be disconnected with a notice of 12 hours. The second is for consumers who accept to be disconnected without notice. These two tariffs are intended for consumers with reserve plants who accept a disconnection lasting until the grid situation is improved. The third tariff is for consumers without reserve plants who accept to be disconnected without notice, but has to be reconnected within 8 hours. A prerequisite for all three tariffs is remote metering as well as remote steering possibilities. The tariffs are available for both high voltage customers and low voltage customers.

5.4 Sweden

5.4.1 Current strategic reserve

Sweden has had a strategic reserve since 2003. The law was originally valid only until 2008. However, the validity has been extended until 2020. A fee levied on balance responsible parties finances the capacity reserve. The volume of the strategic reserve is 1,000 MW for the winter 2015–2016. The reserve includes demand side reductions (340 MW) and two condensing plants (660 MW). Recently, the annual costs have been 12–15 million EUR.

The Ministry of the Environment and Energy sent June 2015 for consultation a memorandum on an extension until 2025 of the law regarding the strategic reserve. Closures of conventional power production, limited transmission capacity from North Sweden to South Sweden and difficulties to adapt demand to available capacity can according to the memorandum result in a troubled capacity situation until 2025. The Government has announced that a proposal to the Parliament will be given in the winter 2016.

Forecast by Svenska kraftnät

Svenska kraftnät reported June 2015 its forecast for the power balance during the winter 2015–2016. The expected peak load was estimated at 25,600 MW for a normal winter and 27,100 MW for a 10-year winter. The expected available derated production capacity (including the strategic reserve) was 28,171 MW. In sum, this implies a surplus in Sweden of 2,570 MW in a normal winter and 1,070 MW in a 10-year winter.

The expected balance differs substantially between the different bidding zones. SE1 and SE2 have a surplus of 2,965 MW and 4,392 MW, respectively, in a 10-year winter, while SE3 and SE4 have deficits of 3,606 MW and 2,680 MW, respectively.

The transmission capacity in the Swedish grid can thus be critical in peak load situations. 6,290 MW has to be transported through cut 2 between SE2 and SE3 if a peak load deficit in South Sweden is to be covered by a surplus in North Sweden. The maximum capacity is 7,300 MW through cut 2, but trading capacity is often smaller depending on the actual grid situation.

For peak load hours in a 10-year winter, Svenska kraftnät expects that imports are possible only from Norway, and that the surplus in Norway will be much smaller than the maximum trading capacity on interconnectors from Norway to Sweden.

Report by Svenska kraftnät

Svenska kraftnät presented December 2015 the report "Adaption of the electricity system to a large volume renewable electricity production",[67] following an assignment by the Government to assess how the electricity system needs to be adapted to manage and enable an increased share of renewable electricity production.

One conclusion is that the current transformation of the electricity system will result in a lower security of supply if no measures are taken. It should be assessed on a national level what risks and what costs the Swedish society is prepared to accept regarding electricity supply. The

[67] http://www.svk.se/siteassets/om-oss/rapporter/anpassning-av-elsystemet-med-en-stor-mangd-fornybar-elproduktion.pdf

Government should assign Svenska kraftnät in consultation with Energimarknadsinspektionen to analyse and propose security of supply criteria for the Swedish electricity system as a whole and its subsystems. Svenska kraftnät points out that the security of supply for the electricity customer depends on the security in the whole supply chain from production to the connection point of the customer.

Another conclusion is that new, weather-independent production capacity is needed when nuclear power is phased out. Such new capacity and regulating resources are primarily needed in SE3 and SE4.

A third conclusion is that it will be very costly to dimension the production and transmission systems according to extreme situations that rarely occur. Demand flexibility is therefore needed from a socio-economic perspective. It is important that the design of the market and the development of business products enable that demand flexibility is fully bid into the market. It will further be important to create incentives and regulations that support the use of batteries in a way that supports the electricity system.

The availability of system services is of vital importance for the security of supply. There are several ongoing activities internally within Svenska kraftnät or within the Nordic cooperation to examine how the need for system services shall be ensured in the future. One important issue for the Nordic area is that the availability of inertia is reduced when big production plants are closed. The problem with less inertia in the power system is a Nordic problem and has to be solved in a Nordic context.

Finally, Svenska kraftnät concludes that an adaption of the electricity system to large-scale renewable electricity production will result in increased grid costs and system services costs and thus increase the electricity costs for consumers.

Reports by NEPP

The project NEPP (North European Power Perspectives) is a research project dealing with the development of the electricity systems and the electricity markets in Sweden, the Nordic countries and Europe. NEPP presented in December 2015 a summary report[68] regarding electricity demand in Sweden, in January 2016 a summary report[69] regarding power market design and in February 2016 a summary report[70] regarding the whole project.

68 http://www.nepp.se/pdf/20_resultat_elanv.pdf
69 http://www.nepp.se/pdf/10_slutsatser_hela_low.pdf
70 http://www.nepp.se/pdf/88_guldkorn.pdf

NEPP estimates that the technical potential for demand flexibility is at least 4,000 MW in Sweden. A 1,900–2,300 MW potential in industries and a 2,000–2,400 MW potential in houses with electrical heating is reported. In addition, NEPP estimates 140 MW potential in offices, 40–50 MW potential in shopping centres and 10–20 MW potential in schools.

However, NEPP stresses that the full potential can be realized only during short periods (1–3 hours). Thereafter will much of withdrawn load come back and increase the consumption in the following hours. This means that only a part of the potential is suitable to reduce a morning peak load. Otherwise, even bigger problems with capacity adequacy will arise in the following hours when withdrawn load returns. NEPP finds it essential that demand flexibility is bid into the day-ahead market and thus affects the clearing of the market. It will be less beneficial for the electricity system and sometimes even problematic if the demand flexibility is realized only as unscheduled demand response in the operation hour .

NEPP concludes that a strategic reserve has a relatively limited impact on the market and is relatively inexpensive, which means that it can be introduced and decommissioned without a major impact on the electricity market as a whole. An introduction of a capacity market is a far greater intervention and will have a significant impact on the electricity market. A strategic reserve can therefore be well suited for peak load plants that are needed only a few hours a year to handle occasional load peaks.

5.5 Nordic area

Forecast by Nordic TSOs

Before each winter, the Nordic TSOs present a common forecast of the power balance for a cold winter day in 1 of 10 winters. The forecast for Nordic peak demand in 2015–2016 is estimated at 71,250 MW. This figure is 2% lower than the estimated sum of the national peaks. The expected available capacity for the market was 70,300 MW, implying a deficit of 950 MW. Imports of this size should be possible for which reason the capacity adequacy was seen as sufficient on a common Nordic level. The areas with the weakest power balances are Finland, South Sweden (SE3 and SE4) and Eastern Denmark (DK2).

The Nordic TSOs have never before reported an expected common power deficit in the forecasted common power balance for the winter to come. The power balance forecast for the winter 2014–2015 was a surplus of 500 MW. The expected peak demand was 71,500 MW, and the expected available capacity for the market was 72,000 MW. The 1,700 MW total Nordic reduction in expected available capacity from 2014–2015 to 2015–16 consists of an 800 MW reduction in Denmark, and a 900 MW reduction in Finland.

The development is even more apparent if the comparison is extended to a five-year period. The power balance forecast for the winter 2010–2011 was estimated to be a surplus of 1,800 MW (73,900 MW production and 72,100 MW consumption). This means that the expected production capacity has decreased 3,600 MW in five years, of which 1,900 MW relates to Denmark, 1,700 MW relates to Finland, and 500 MW relates to Sweden. The expected production capacity, however, increased by 500 MW in Norway.

Report by Thema

The Thema report Capacity adequacy in the Nordic electricity market (THEMA Report 2015–10) was commissioned by Nordic Energy Research and presented in June 2015. The report analysed the following issue: What market solutions may be used to manage capacity adequacy in the Nord Pool market area, and how could an efficient transition to adequate market solutions be achieved?

A simplified model analysis was conducted using the The-MA power market model. The model simulations were based on a reference scenario and six stress cases. The main conclusion is that there is little evidence of severe capacity adequacy challenges in the Nord Pool market area to 2030. The availability of nuclear generation and interconnector outages were identified as potential sources for capacity shortages.

The Nordic market as a whole will likely rely on imports during maximum peak hours. This was not seen as posing a problem, as the Nord Pool market area has ample exchange capacity with several other markets and the Baltic area generally has a surplus during peak load.

The report identified some barriers which may adversely affect future capacity adequacy. Efficient short-term operation of the system and efficient long-term investments rely on efficient price formation, adequate cost recovery and making sure that price signals reach suppliers and consumers. The price cap in the day-ahead market was not seen to constitute a capacity adequacy concern, as the maximum price is rarely achieved.

Reserve markets may be improved by harmonizing product definitions and integrating markets. The possibility of reserving interconnector capacity for exchange of reserves should be pursued within current European regulation. Provision of ancillary services should be properly remunerated or acquired on market based terms, instead of being set as requirements for certain generators. The design of renewable support mechanisms should be revised. Grid tariffs for consumers should be designed so that relevant price signals reach consumers and are not muted by ill-designed grid tariffs.

The report states that there is probably sufficient peak and flexible generation capacity in the Nordic market to manage most situations in the next 15 years. In the short run, it is probably cheaper to increase the contribution of peak and flexible capacity from generation than from demand. Hence, it is important to remove barriers to efficient investment and utilization of peak and flexible generation.

Roundtable of Nordic Power Stakeholders

The Roundtable of Nordic Power Stakeholders[71] was held on 1 December 2015 in order to discuss the challenges in the Nordic power system. Four important trends were identified.[72] Generation adequacy is being reduced, the need for system flexibility is increasing, inertia is becoming a scarce resource and interconnector capacity is increasing relative to installed generation capacity. These trends challenge system operations and can pose a threat to security of supply if left unaddressed.

The Roundtable pointed out that market based solutions should be pursued as a first option. It is important to further develop markets for flexibility, and particularly ensure that all services requested and delivered to uphold system security are duly rewarded on a market based basis. A strong CO2-price should be driving investments into new capacity and a strong grid will be an important part of the solution in all scenarios. The lack of inertia over time is concerning and needs to be addressed with market based solutions to the greatest extent possible.

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[71] The Roundtable had representation from Ministries, Regulators, TSOs and key market players.

[72] http://statnett.no/Global/Dokumenter/Kraftsystemet/Systemtjenester/Proceedings%20-%20Roundtable%20of%20Nordic%20Power%20Stakeholders%2001.12.15.pdf

5.6 Implications from the peak load in week 1–3 2016

Week 1–3 2016 were very cold in the Nordic area. The Nordic consumption was higher than 69,000 MW during 25 hours in five different days according to preliminary data presented on Nord Pool website. A new Nordic consumption record (70,159 MW) was registered on 21 January hour 08–09.

Norway registered a new consumption record (24,485 MW) in the same hour as the new Nordic record consumption. Finland registered a new consumption record (15,105 MW) on 7 January hour 16–17 CET. The production in Finland during that hour was 10,874 MW and remaining production capacity in Finland was about 800 MW (including the strategic reserve).The highest peak load in Sweden (26,714 MW) occurred 15 January hour 08–09 while the highest peak load in Denmark (5,816 MW) occurred 21 January hour 17–18.

The sum of the highest national peak loads in week 1–3 was 72,120 MW or 2.8% higher than the highest Nordic peak load. The sum of the highest peak loads in the twelve Nordic bidding zones was even higher, 73,447 MW or 4.7% higher than the highest Nordic peak load. DK1, NO3, NO4, SE1, SE2 and SE4 had their highest peak loads during other hours than the hour of the highest national peak load.

This implies that a probabilistic assessment of capacity adequacy shall take into account pooling effects. The highest Nordic peak load is normally slightly smaller than the sum of the highest national peak loads. The highest national peak load is normally smaller than the sum of the highest peak loads for the bidding zones within the country. However, there is of course always a probability that an extreme weather situation occur for the whole area and that there will be no pooling effects in such a situation.

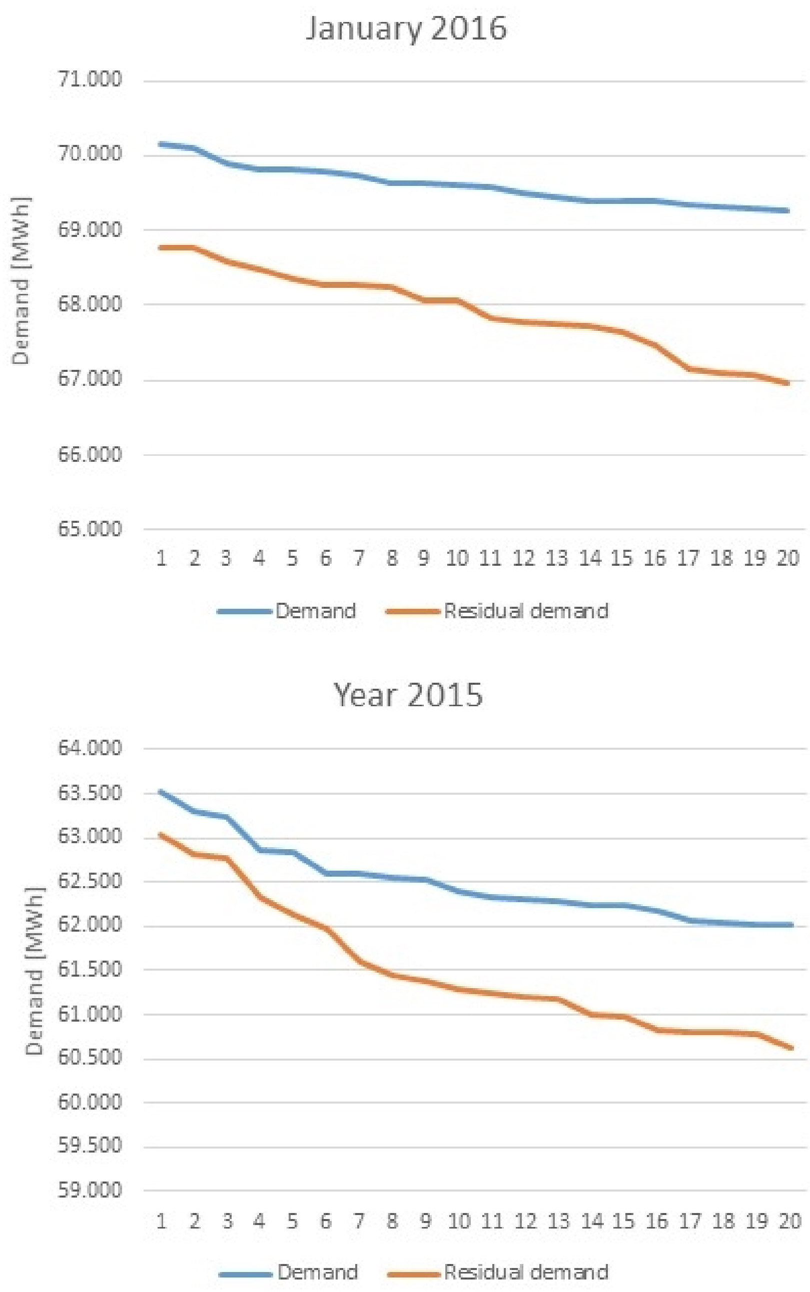
A probabilistic assessment of capacity adequacy shall also take into account possible contribution from weather–dependent electricity production such as wind and solar. There is normally higher wind power production in the winter months than in the summer months. During week 1–3 varied Danish wind power production between 25 MW and 3,673 MW while Swedish wind power production varied between 471 MW and 2,938 MW. During the hour with the new Nordic record consumption was the wind power production 612 MW in Denmark and 695 MW in Sweden.

The term “residual demand” denotes consumption minus weather-dependent electricity production. The residual demand has to be covered by conventional production and/or cross-border trade in order to achieve balance. The maximum residual demand in week 1–3 occurred in the same hour as the new Nordic record consumption occurred. The following two figures show for January 2016 and the whole year 2015 one duration curve with the 20 highest Nordic values for hourly consumption and one duration curve with the 20 highest Nordic values for residual demand.

The figures show how different January 2016 was from year 2015. There were no cold periods in 2015. The Nordic peak load in 2015 was 6 600 MW lower than the new record consumption January 2016. The Nordic consumption was higher than the 2015 peak load in all hours between 06.00 and 22.00 on 7, 20 and 21 January 2016.

Both the figure for January 2015 and the figure for year 2015 show a steeper gradient for maximum residual demand values than for maximum consumption values. The reason is that some hours with very high consumption are calm while other hours with very high consumption are windy.

Figure 23: The 20 highest demand values and residual demand values in January 2016 and the whole year 2015



Source: Nord Pool.

The figures implies that the expected utilization time of peak production plants to cover peak residual demand is dependent on the share of weather-dependent production in the production system. The higher share, the shorter utilization of peak production plants and a need for even higher peak prices to justify sufficient investments in peak plants. Our conclusion is that a higher share of weather-dependent production makes it even more urging to develop market design and business models in such a way that the existing potential for demand response can be utilized.

The Nordic electricity market functioned very well during the peak load weeks 1–3. No severe disturbances or outages occurred. There was extra production capacity available during all hours. The Nordic spot prices were consequently rather low compared with the price spikes that have occurred in peak load situations in earlier years.

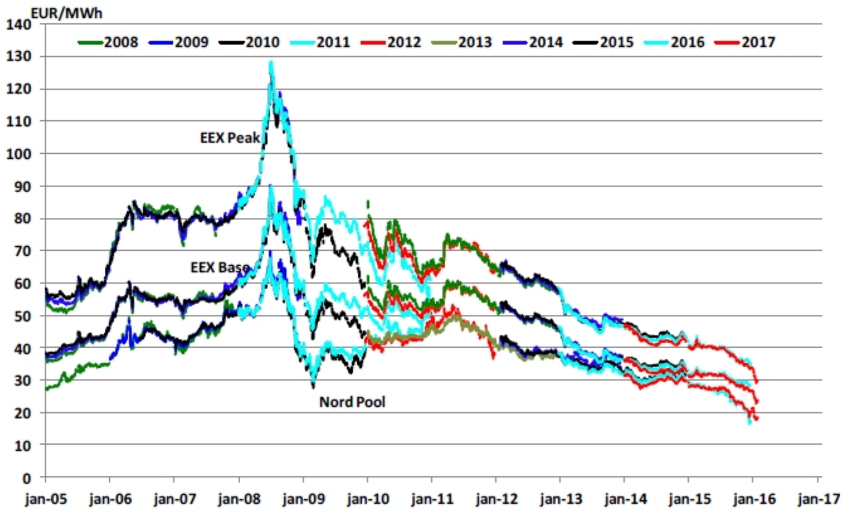
The highest spot price during week 1–3 was 214 EUR/MWh on 21 January hour 8–9. It can be seen as a sign of a well-functioning market that the highest price occurred in the hour with maximum residual demand (and maximum consumption). The spot price 214 EUR/MWh was common for DK2, FI, NO1, NO3, NO4 and SE1–SE4. This means that there were unused available transmission capacities between these areas.

The remaining Nordic areas, DK1, NO2 and NO5, had another common price 85 EUR/MWh together with Germany and the Netherlands. This means that there were unused available transmission capacities between these areas but that all available transmission capacities to the high-price Nordic areas were fully used.

All of the neighbouring countries to the high-price areas had lower spot prices and all available transmission capacities could be used for imports from these countries. However, Germany and Poland had because of internal bottlenecks limited their export capacity to Sweden. The German export capacity was limited from 600 MW to 302 MW and the Polish export capacity was limited from 600 MW to 36 MW.

Prices in the Nordic forward market are normally increasing in peak load weeks with high demand and low precipitation. However, the forward prices for coming years decreased in week 1–3. The reason was that there was a steep fall in fuel prices and CO2 prices during these weeks. The following figure shows how the Nordic forward prices for the next calendar years have developed since 2005. The figure shows also German forward prices for the next calendar years regarding base load (EEX Base) and peak load (EEX Peak). German peak load is defined as weekday hours between 08.00 and 20.00.

Figure 24: Forward prices for the next calendar years regarding the Nordic area and Germany



Source: Nasdaq OMX Commodities, EEX, Svensk Energi.

The figure shows how low current forward prices are. The Nordic forward prices for the next calendar years have never been as low as now during the latest ten years. The Nordic forward price for year 2017 was 18.5 EUR/MWh in the end of January 2016 while it was 19.7 EUR/MWh for year 2020. Neither the German forward prices have been as low as now during the latest ten years. The German price for base load was 23.6 EUR/MWh for year 2017 in the end of January 2016 while it was 23.0 EUR/MWh for year 2020.

5.7 Need for capacity mechanisms in the Nordic countries?

There have been some black-outs in parts of the Nordic area during the last decades. These black-outs have all been caused by faults in transmission facilities combined with high power transfers in the transmission system. Power transfers shall be restricted to a level giving sufficient reliability margin if a fault occurs. However, the reliability margin has not been sufficient to enable system security in these cases of combined faults. A black-out caused by insufficient production capacity has never occurred in the Nordic area during the last decades.

A TSO has the duty to maintain system security on such a level that dimensioning faults do not lead to extensive disturbances. This means that the TSO reserves for frequency control and management of disturbances have always to be upheld. If necessary, TSOs can order forced load shedding in order to maintain system security. Nordic TSOs have never during the latest decades performed forced load shedding because of lacking production capacity. However, capacity adequacy is a probabilistic concept – not an absolute concept. There is always a risk that a combination of faults or extremes may happen that necessitates forced load shedding.

It can be noted that Nordic TSOs have before each winter concluded that there is sufficient capacity to cover peak load. Another sign of sufficient current capacity is the problem-free market clearing during week 1–3 this year in spite of Nordic record consumption and record consumption in Finland and Norway.

However, the situation may change rapidly. Some condensing plants are already closed, for some other there is now a decision to close. In addition, we believe that there are owner discussions regarding closing for most of the remaining condensing plants. The absence of real price spikes during the recent peak load weeks will probably intensify such discussions. We see a significant risk that most of the Nordic condensing capacity will close within a few years.

Also Swedish nuclear capacity is under stress. One year ago, most studies assumed that the ten Swedish nuclear reactors would continue to operate also after 2020. Owner decisions in autumn 2015 mean that at most six reactors will be in operation after 2020. In addition, owners of the six remaining reactors have warned that if their costs are not reduced, more closures may be necessary because of the steep fall in forward prices.

Plant closures do not only worsen the capacity situation in the concerned area. They may also reduce the capacity possible to import to another area in a peak load situation and thus jeopardise capacity adequacy in that area.

Areas that may be depending on imports in peak load situations are Finland, the two southern bidding zones in Sweden (SE 3 and SE 4) and Eastern Denmark (DK 2). Also some Norwegian bidding zones (NO1 and NO3) may be dependent on imports in peak load situations but possible imports from other Norwegian areas are seen as adequate.

Studies in recent years regarding capacity adequacy in the Nordic area have not included the risk that most of existing condensing plants may soon be closed and that at most only six reactors will be operational in Sweden after 2020. The conclusions in the studies may thus be too positive regarding capacity adequacy.

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[73] http://www.bmwi.de/DE/Presse/pressemitteilungen,did=736020.html?view=renderPrint with comments on: http://www.germanenergyblog.de/?p=19505

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Sammenfatning

Om den nuværende indretning af elmarkedet understøtter en tilstrækkelig forsyningssikkerhed debatteres for tiden i mange EU lande. Store lande som Tyskland, Storbritannien, Frankrig og Italien har besluttet at implementere ekstra tiltag, herunder kapacitsmekanismer, for forsyningssikkerhedens skyld. Denne rapport beskriver og analyserer fordele og ulemper ved en række af de kapacitetsmekanismer der enten er foreslået eller allerede implementeret i Europa, og indeholder ligeledes estimater for hvordan de nordiske elpriser påvirkes. Endvidere gennemgås forskellige vurderinger af el-forsyningssikkerheden i de Nordiske lande. Det beskrives bl.a. at der må påregnes yderligere reduktion af den termiske kapacitet før det nordiske marked er i kommerciel balance. I rapporten anbefales det at forsyningssikkerheden ses i et regionalt fremfor nationalt perspektiv samt at der fortsat arbejdes på at implementere tiltag der kan øge fleksibiliteten i markedet. Det anbefales også at de nordiske lande fortsætter fokus på strategiske reserver som et effektivt og midlertidigt redskab til sikring af forsyningssikkerheden, fremfor at vælge permanente og markedsforvridende tiltag som i fx. Frankrig, Storbritannien, og Italien.

Appendix 1: Analysis of needed Demand response (or strategic reserves) in the Nordic region

In the Energy Only Market power producers bid at their short run marginal generation cost. Hydro power plants with reservoir capacity is an exception since these power plants have the possibility to adjust the timing of generation to ensure as high a price as possible for a limited amount of hydro energy.

For investments in a power plant to be profitable the expected profit contribution i.e. annual sales minus the sum of short marginal generation costs needs to exceed the plant's fixed cost. This leads to a market structure consisting of a combination of plants with relatively high fixed cost and low short run marginal costs (providing baseload) and plants with low fixed cost and high short run marginal cost (providing peak load).

Fixed cost of peak power plants

Even the least expensive peak power plants such as gas or diesel engines have considerable annual fixed costs. Energinet.dk states annual capital costs for a new diesel engine at approx. EUR 40,000 per MW/annum (Energinet.dk, 2015b) whereas system operators provide estimates of around EUR 100,000 per MW/annum (see Newell *et al.*, 2014). If peak power is provided by older power plants, close to being worn out, fixed costs may be as low as EUR 15,000 per MW/annum. In the subsequent analyses, we assume fixed cost of EUR 50,000 per MW/annum.

How will peak power plants cover their fixed costs?

The question is then how peak power plants achieve a sufficient margin to cover their fixed cost? To achieve this balance we need resources with very low or no fixed costs. In this context demand response is normally highlighted, i.e. consumers which are willing to abstain from using power at very high prices. In scarcity situations, these consumers will set the price of electricity at a higher level than the short run marginal costs of peak power plants and thereby create the margin to cover the fixed costs of the peak power plants. The supply side may also provide capacity at very low or no additional capacity costs, for example some power plants, may be able to increase generation beyond their nameplate capacity at the expense of higher fuels costs or increased wear. Similarly, there is also a potential for activating emergency power systems in the electricity market if prices are sufficiently high.

In theory, the market should be able to determine the right balance between supply and demand. When electricity prices become sufficiently high the consumers with the lowest willingness to pay will withhold from using electricity. In practice, it is a challenge that many consumers have contracts with their electricity suppliers, which do not expose them to the electricity prices in the spot market. In addition, there may be considerable transaction costs connected to the development of demand response from consumer side.

Reaching the price ceiling causes load shedding

To protect consumers from very high prices most (if not all) electricity markets impose price ceilings; a maximum price of electricity in the market. If the price ceiling is reached involuntary disconnection of consumers is needed, so-called brown outs. Contrary to a blackout, a system collapse, a brown out is a controlled disconnection of pockets of customers. This is usually done according to a schedule protecting consumers, which are believed to have a particularly high willingness to pay for electricity such as hospitals, railways and certain industries. If the price ceiling is lower than the willingness to pay for disconnected consumers it may pose a challenge for the functioning of the market. In this case, electricity prices should be able to reach a higher level and thereby provide a stronger incentive to invest in peak power capacity.

Disconnections approx. 17 hours a year if no demand response

In the Nordic electricity market, the price ceiling is EUR 3,000 per MWh. Assuming – which is not very realistic – that there is no demand response (or other sources with no or very low capital costs) in the market; disconnections should on average take place around 17 hours a year. The rationale is that it takes 17 hours with a profit contribution of approx. EUR 2,900 per hour (price ceiling minus short run marginal cost of approx. EUR 100 per MWh for a peak power plant) to recover the fixed capital costs of new peak power capacity of approx. EUR 50,000 per MW/annum. As we will show in the subsequent sections, normally only a small fraction of demand would have to be disconnected in these hours. The calculation is a simplification, as it does not consider other potential earnings of the peak power plants, for example in the market for balancing power. This may reduce need for disconnections.

The above calculations also provide insight into the level of demand response that is required to ensure a market in balance without an involuntary disconnection of consumers. In principle, consumers are only required to voluntarily disconnect 17 hours a year at the price of 2,999 EUR per MWh to ensure a well-functioning market. If consumers' willingness to pay for electricity is lower, more hours are required where demand sets the power price. If for example the willingness for power is EUR 300 demand response will have to be activated 250 hours a year (EUR 50,000/(EUR300–EUR100). It is also apparent that increasing the price ceiling will reduce the need for demand response.

By analyzing the load curve in a power system it is possible to estimate the amount of demand response required to have a functioning market without brownouts. The graphs below show duration curves for Nordic electricity system (DK, FI, NO, SE) for demand as well as residual demand, i.e. demand minus wind generation in 2015. We would have preferred to also subtract other non-dispatchable renewable energy sources in the residual demand curve, such as solar power and run-of-river hydro generation, but hourly data was not available.

The total share of wind power in the system was 8.9%. In the second graph we have zoomed in on the 300 hours with the highest demand.

We assume that the price ceiling is EUR 3,000 per MWh as today. In a situation with no flexible demand there would as mentioned before be around 17 hours with involuntary disconnections of consumers. It is reasonable to assume that disconnections will mainly take place when demand peaks i.e. due to insufficient capacity to cover peak loads (disconnections could also take place at other times of the year for example in situations with many power plants outages).

The figure with the residual demand is the most relevant to look at since this is the demand that would have to be covered by thermal units (or imports). In this situation the market driven dispatchable capacity would be just below 60,800 MW in the system, because at this level of dispatchable capacity there would be 17 hours where demand is not satisfied and the price ceiling is reached (bold red line in the graph). Up to 2,200 MW of demand would have to be disconnected in the most strained hour, this corresponds to 3.5% of peak demand. In total 14,278 MWh of demand is disconnected; about 0.004% of total demand or 20 minutes of disconnection time for the average consumer annually. A similar level of demand response is required to have a well-functioning market (without involuntary disconnection of consumers) as long as consumers withdraw from using electricity at a price very close to the price ceiling.

Strategic reserves mimic demand response

If brownouts are not considered acceptable by policy makers strategic reserves can provide backup. The calculations indicate that the level of strategic reserves in the Nordic system would also have to be in the order of 2,200 MW if there is no voluntary demand response in the system. The strategic reserve simply takes the role of the lacking demand response. This calculation assumes, that the strategic reserve is activated at the price ceiling. If it is activated at a lower price, the reserve would have to be larger as we will show in the next section.

Figure 25: Duration curves for the Nordic system for demand and residual demand (demand minus wind power)

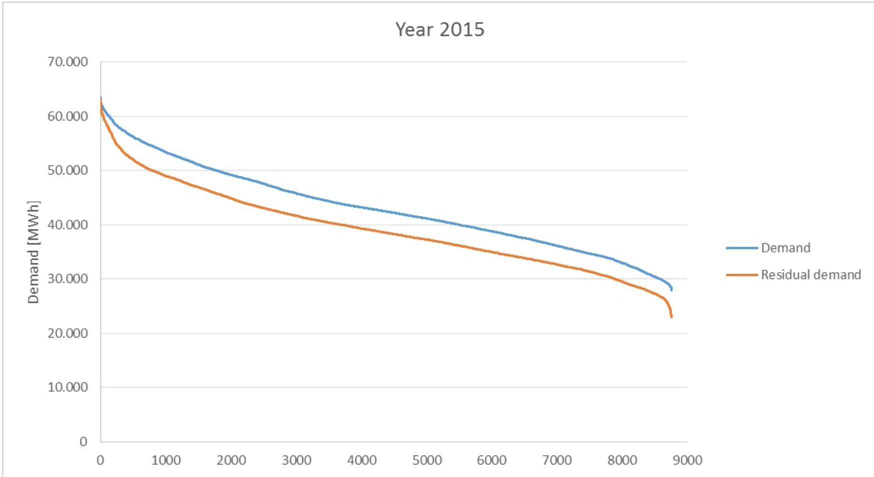
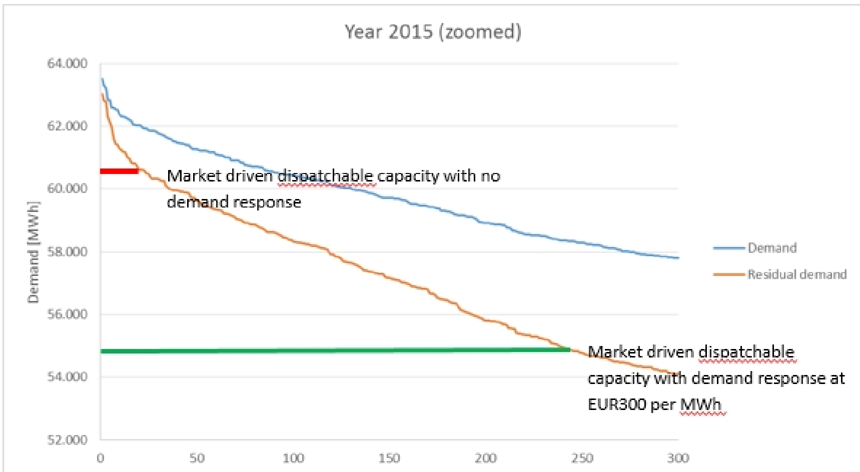


Figure 26: Duration curves for the Nordic system for demand and residual demand (demand minus wind power). Zooming in on the 300 hours with highest demand



In the example, where consumers abstain from using power at a power price of EUR 300 per MWh, the market driven level of thermal capacity would only be just below 54,800 MW (bold green line in the graph). At this level there would be 250 hours where demand is not satisfied and the price of EUR 300 is reached; sufficient to cover the fixed costs of the peak power units. In this case close to 8,300 MW of demand would have to be disconnected in the most strained hour, this corresponds to 13% of peak demand. In total, some 772,000 MWh of demand needs to be voluntarily disconnected; this equals 0.2% of total demand or 1,075 minutes (18 hours) of disconnection time for the average consumer per annum.

A lower activation price increases the demand for strategic reserve

The calculations also show that if there were no demand response in the system, but a strategic reserve activated at EUR 300 per MWh, its size would have to be in the order of 8,300 MW. That is almost four times as much compared to a situation where the strategic reserve is activated at the price ceiling of EUR 3,000 per MWh.

It is also apparent from the graph above, that the residual peak demand curve is steeper than the traditional peak demand in a system without wind power. Therefore, a higher level of demand response (both in terms of MW and in terms of MWh) or a larger strategic reserve is required to have a well-functioning market in a system with high level of wind and solar.

The table below shows what level of demand response (or strategic reserve) is required to have a functioning Nordic electricity market in a situation with current level of wind power in the system and a situation without wind power. The requirement for demand response or strategic reserve increases by close to 50% (from approx. 1,500 MW to 2,200 MW) with current level of wind power compared to a situation with no wind in the system.

Table 8: Levels of demand response required in the Nordic system to avoid involuntary disconnection (brownout) of consumers

	Demand response is active at	Required demand response, MW (in% of peak demand)	Required demand response, MWh in%	Required demand response, hours per annum
9% wind power as in 2015	EUR 3,000 per MWh	2,200 (3.5%)	0.004	0.3
	EUR 300 per MWh	8,300 (13.0%)	0.2	20
No wind power in the system	EUR 3,000 per MWh	1,500 (2.3%)	0.002	0.2
	EUR 300 per MWh	5,200 (8.2%)	0.1	11

Variable renewables increases the demand for response or strategic reserves

To see the impact of even higher levels of variable renewables, we prepared a similar table for the electricity system of Western Denmark (DK1) where wind and solar power generation in 2015 equaled 59 per cent of demand. In this case, we see a quadrupling of the need for demand response or strategic reserve (from approx. 50 MW to 200 MW) when wind and solar generation is considered. This calculation assumes that demand response (or the strategic reserve) is activated at the current price ceiling.

Table 9: Levels of demand response required in DK1 to avoid involuntary disconnection (brownout) of consumers

	Demand response is active at	Required demand response, MW in%	Required demand response, MWh in%	Required demand response, hours per annum
59% wind/solar power as in 2015	EUR 3,000 per MWh	200 (6.0%)	0.006	0.5
	EUR 300 per MWh	680 (20.5%)	0.2	20
No wind and solar in the system	EUR 3,000 per MWh	50 (1.6%)	0.002	0.2
	EUR 300 per MWh	240 (7.1%)	0.1	8

Summary

To summarize, the level of demand response required to have a well-functioning electricity market is highly dependent on the price level at which demand is activated. A higher price level directly reduces the need for demand response. The same is the case for strategic reserves. If the strategic reserves is activated at EUR 3,000/MWh compared to EUR 300/MWh the requirement in MW will be almost four times lower. Finally, we see that increasing levels of wind power in the system increases the amount of demand response required to have a well-functioning market. Solar power and run-of-river hydro can be expected to have the same impact on the market.

Appendix 2: Model details and results

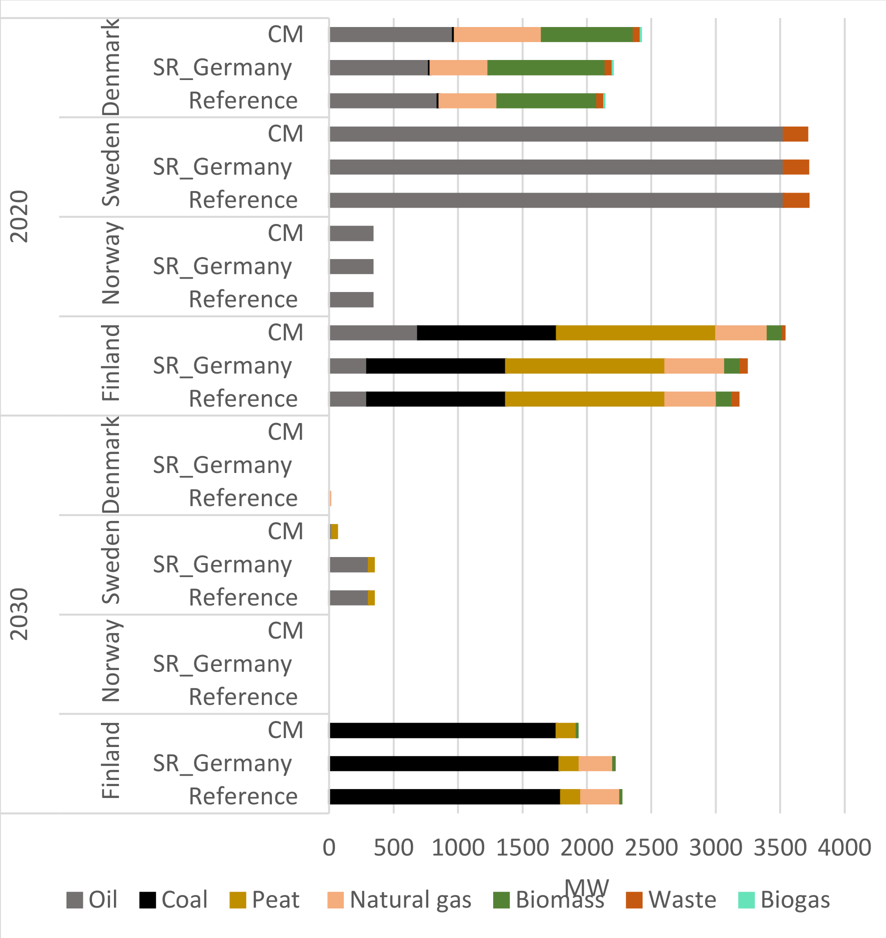
Decommissions and investments

Decommissioned capacities

The model decommissions power plants across the Nordic countries, of which the majority includes oil-fired capacities. From a national perspective, most power plants are decommissioned in Finland including 2.9 GW oil capacity, 2.8 GW coal capacity, and 1.8 GW gas capacity. With respect to the decommissioned Finnish oil capacity, it is worth to recall that the capacity input used for the modelling here includes about 2 GW oil capacity, which is not a part of the ENTSO-E estimates for net generating capacities (cf. main input data section).

The far majority of model decommissions have taken place in 2020 but some decommissioning occur in 2030, see the figure below. Note that the decommissioning of plants is based on the model optimization without taking the long lead times in real-life decision making into account. If new investments was restricted in the model (e.g. by imposing a very high risk rent), a substantial part of the decommissioning would probably not take place. The general reluctance towards new investments in power plants is therefore not properly mirrored in the figure below.

Figure 27: Decommissioned capacity (MW) in the year 2020 and 2030 for the Nordic countries

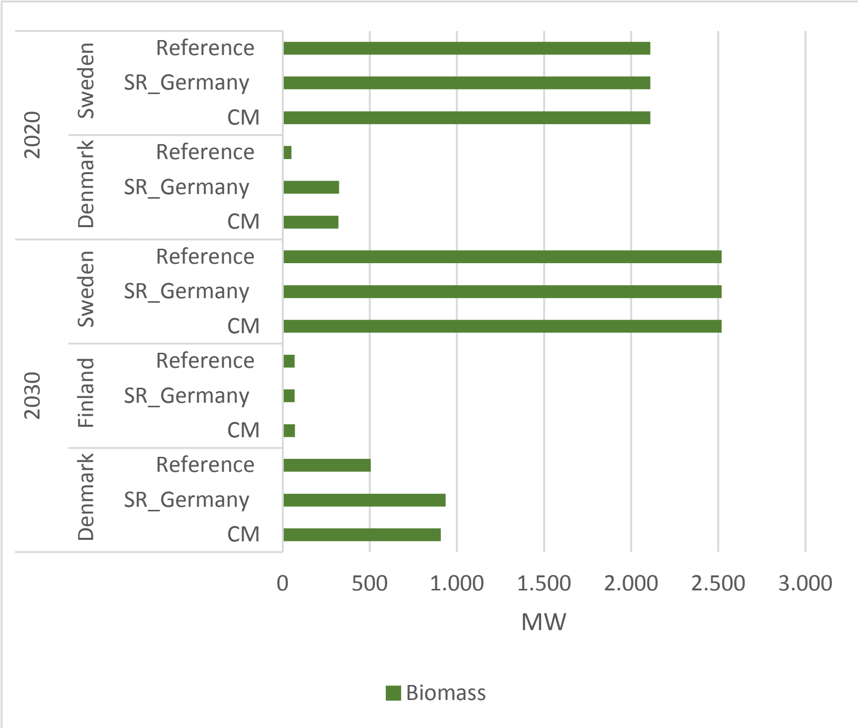


Note: For Denmark, decommissioned capacity includes minor coal plant capacity which have been refurbished to use biomass. NB: This figure only includes capacity decommissioned by the model. Other capacities, e.g. Nuclear capacities in Sweden is decommissioned exogeneously.

New capacities

Alongside the decommissioning of certain power plants (with high fixed costs), the model invests in new plant capacity. This capacity consists of wind turbines, solar power and biomass plants. However, in Finland (and to a lesser extent Sweden), the model also invests in new natural gas fired power plants. In below the model investments for thermal capacity is shown. Expansions in RE capacity are not decided by the model but based on projections from national source and is not shown below.

Figure 28: Investments in thermal capacity (MW) in the year 2020 and 2030 for the Nordic countries



Resulting Capacity balances

The resulting capacity balances for the Nordic countries are presented in Figure 29 across scenarios and the Nordic countries and in Figure 2030 for the reference scenario aggregated for all the Nordic countries. The figures show an increase in the share of fluctuating RE capacity. This development leads to greater variation in electricity prices with several high and low prices compared to the situation today, and this affects the operation of electricity and district heating systems in the Nordic countries.

Figure 29: Total installed capacity in 2020 and 2030 for the Nordic countries (MW)

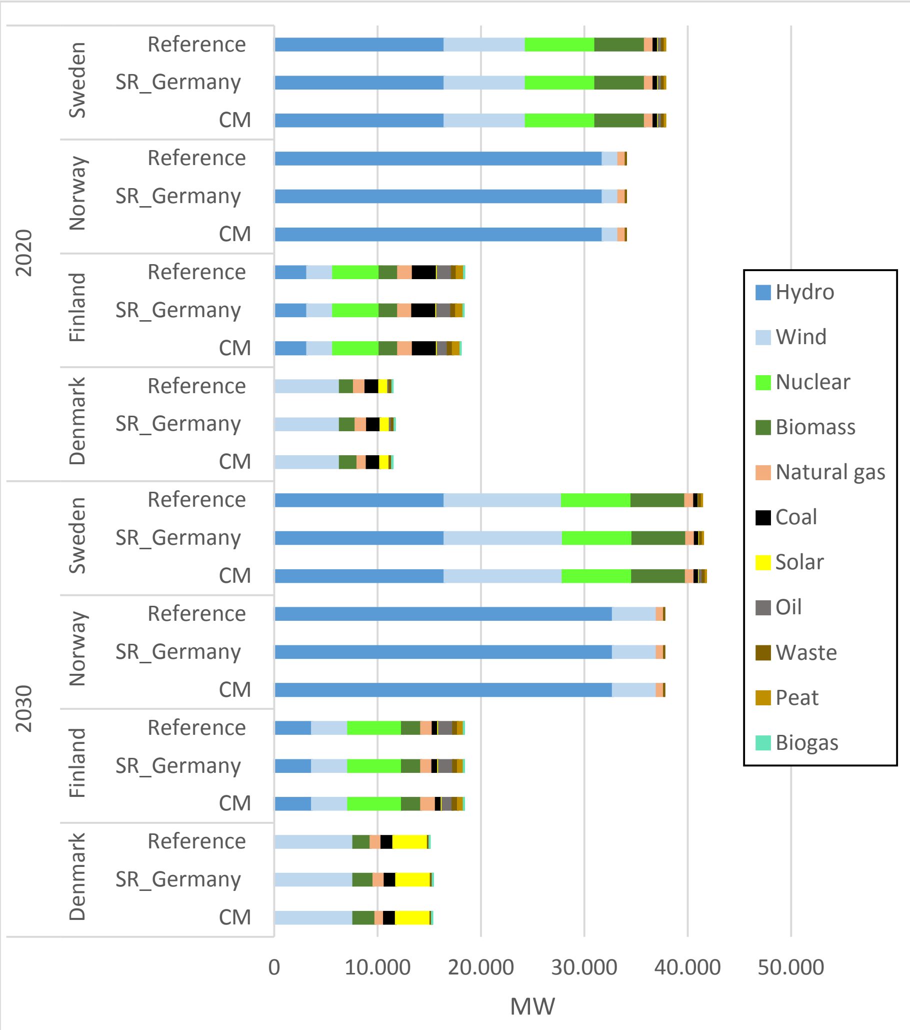
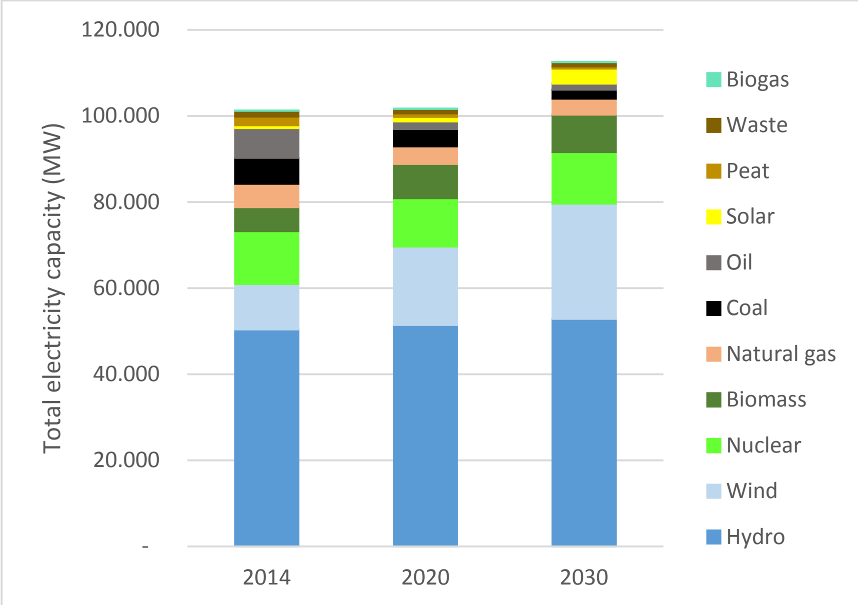


Figure 30: Total installed generation capacity for the Nordics in 2014, 2020 and 2030 given in MW for the reference scenario



Reference scenario assumptions

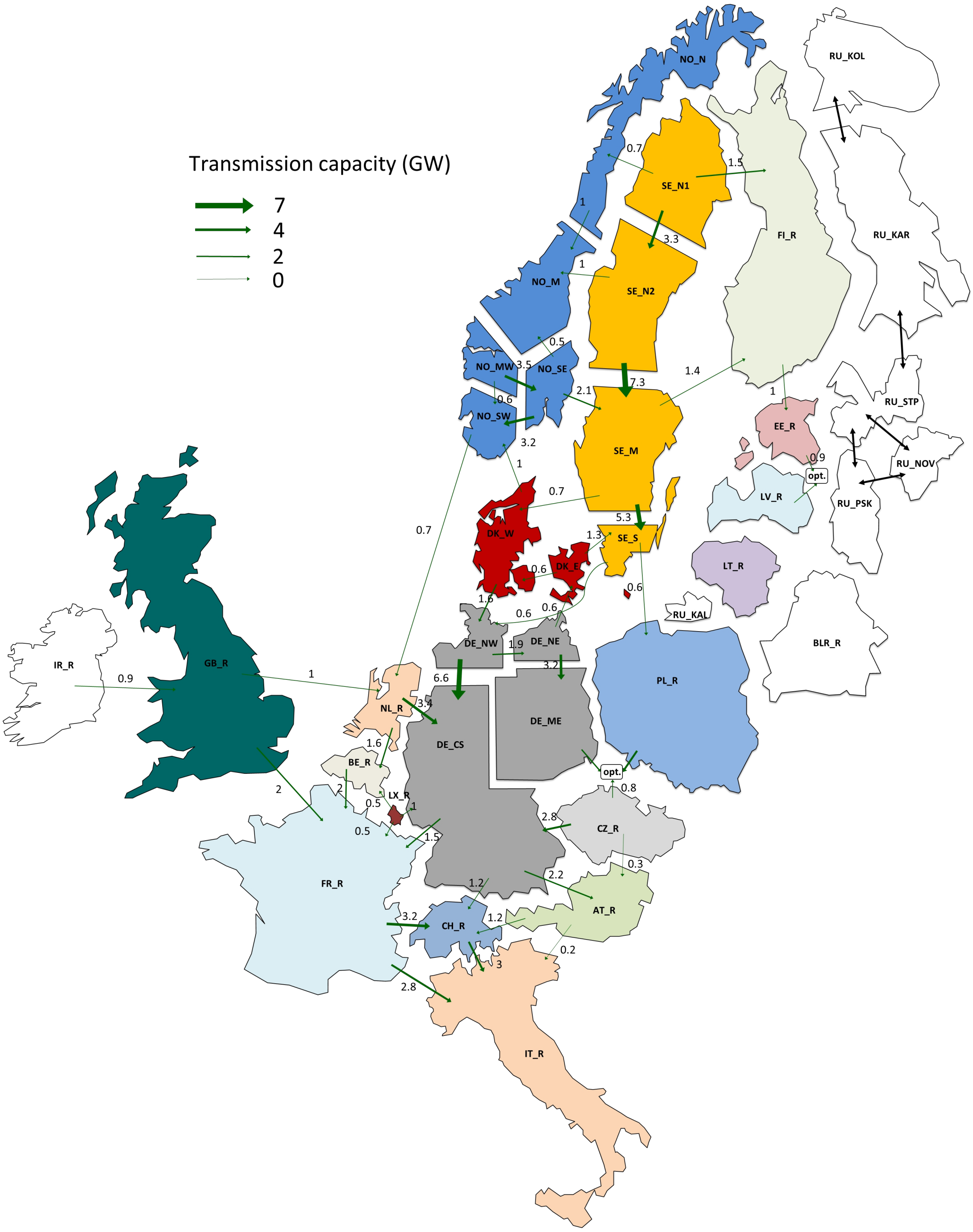
This section provides a detailed overview of the core data used in the model scenarios, including capacity data for the base year 2014, interconnector capacities and included expansions plans, fuel prices and more.

The simulations of the power and district heating system is made from a premise that countries in the long term are pursuing an ambitious climate policy, this reflected in fuel and CO2 prices. In the short term developments for each country are governed by national targets for RE generation.

Transmission capacity

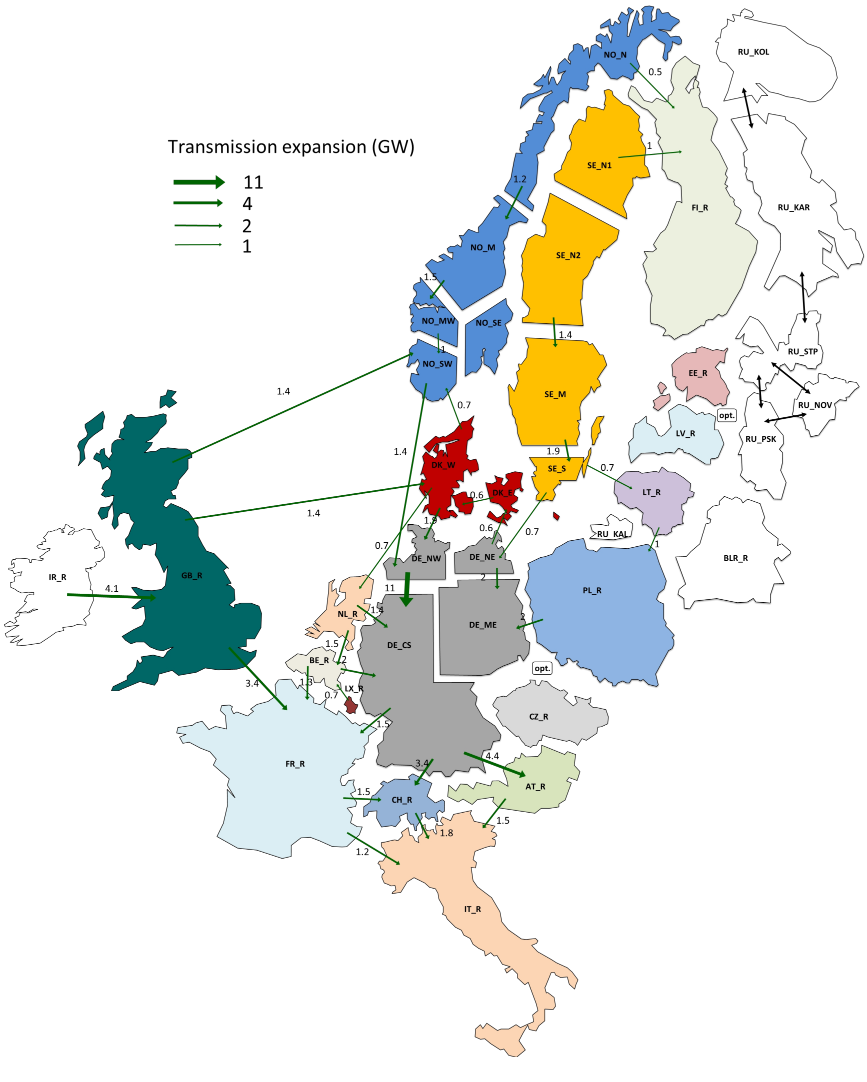
The transmission grid for 2014 is shown to demonstrate the existing transmission lines represented in the model, see Figure 31. The assumptions on the development of the transmission grid towards 2030 is based on the Ten Year Network Development Plan (TYNDP) published by ENTSO-E. The network expansions for 2030 are shown in Figure 32.

Figure 31: Transmission grid in 2014 for model regions



Note: White regions are not included in the simulation. Capacities are given in GW.

Figure 32: Transmission expansions from 2014 to 2030 given in GW



Fuel prices

Fossil fuel prices are based on a combination of forward prices and price predictions from IEA's World Energy Outlook 2015 (WEO2015), structured in the following way:

- Short term: Forward prices until 2020.
- Medium term: Convergence prices between forward and IEA prices. The weights attached to IEA prices are gradually increased towards 2030, where IEA prices are weighted by 1 and forwards by 0.
- Long term: IEA price predictions.

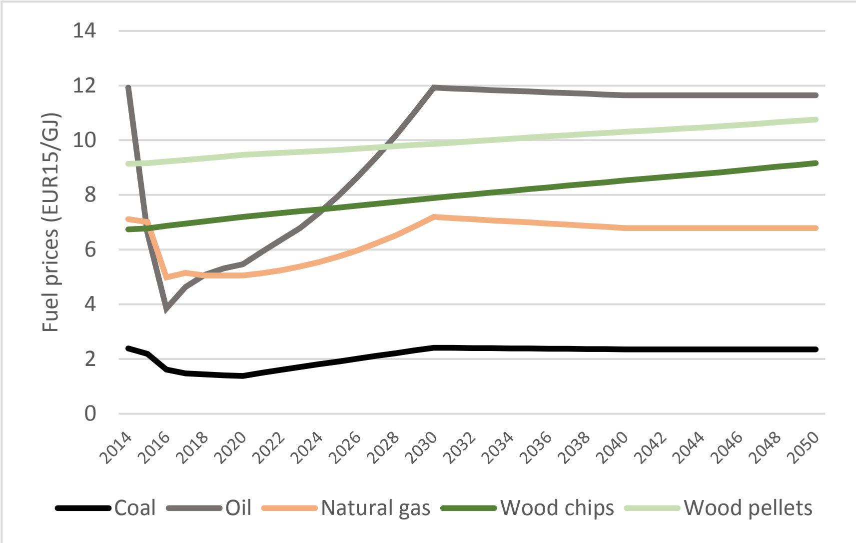
The IEA's main scenario is called the New Policies scenario, but three alternative scenarios are also developed in the WEO2015. These are the: 1) Current Policies; 2) 450 PPM; and 3) a Low Oil Price scenario. This analysis uses the low price scenario – 450 PPM – in the medium term as input to the convergence prices and fully in the long term. The 450 PPM scenario assumes that the world takes a progressive policy approach to climate change and reaches the 2 degree climate goal.

This analysis favours the 450 PPM scenario for two reasons. Firstly, the IEA has consistently underestimated RE-technology developments historically, which has led to overestimated fossil fuel prices.[74] This calls for picking a lower price scenario, which also align better with the current market prices. Secondly, the new COP21 climate agreement in Paris has taken place since the scenario development in WEO2015, which will likely lead to a more ambitious approach to climate change globally. This will reduce demand for fossil fuels, and in turn impose a downward price pressure. The size of these effects are highly uncertain.

Biomass prices are based on the assumptions of the Danish Energy Agency until 2030. Between 2030 and 2050 prices are assumed to linearly increase to a level which is 50% above the 2030 level.

[74] Vox (2015).

Figure 33: Fuel price projections 2014–2050 given in EUR15/GJ for prices at power plant



Note: In the short run prices are based on market forwards/futures and then converging to World Energy Outlook 2015's 450ppm scenario in 2030.

CO2 price

In the first two months of 2016, EU ETS CO_2 prices traded for about 5–6 EUR/ton. EU ETS futures for 2020 traded for only slightly more. This price level is much lower than most medium and long term forecasts.

The spread in the price projections of the IEA's World Energy Outlook 2015 is wide. In the New Policies scenario, EU-ETS CO_2 prices are projected to rise from 22 EUR/ton in 2020 to 50 EUR/ton in 2040 (2014-prices). In the 450 PPM scenario – where high CO_2 prices are assumed to drive the green transition – EU ETS CO_2 prices are projected to rise from 22 EUR/ton in 2020 to 140 EUR/ton in 2040 (2014-prices).

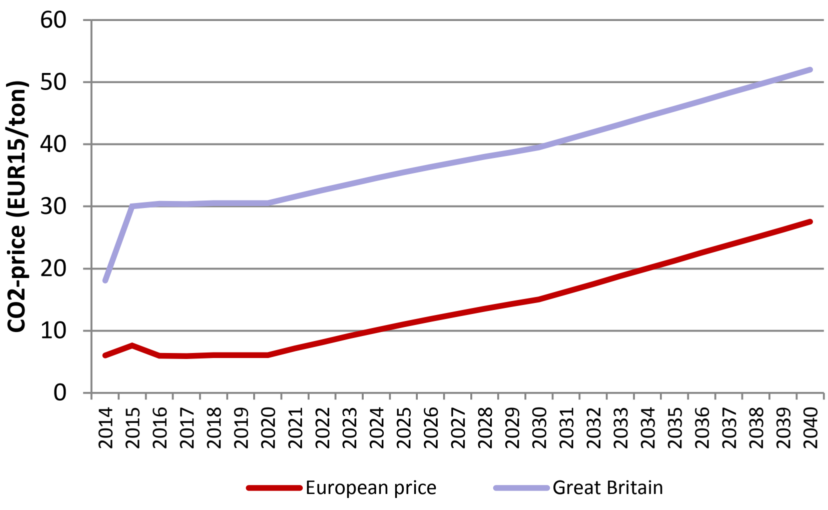
By comparison, the EU impact assessment assumes a 40 EUR/ton CO_2 price by 2030 to attain the 40% CO_2 reduction target. Adding energy saving measures reduces the 2030 price to 22 EUR/ton and adding support for RE deployment and EE reduces the price to 11 EUR/ton. In a conservative scenario without enabling polices for technological development the 2030 CO_2 price is 53 EUR/ton if the same reduction target is to be met. All prices are 2010-prices. The key question is if the CO_2 price will actually increase, or if subsidies will instead drive the green transition.

This analysis assumes that the main driver of the green transition will be subsidies, and not high CO_2 prices in the quota sector. CO_2 prices are assumed to land on 15 EUR/ton, aligning reasonably well with the EU impact assessment, when subsidies and energy efficiency policies are implemented. However, the CO_2-price projection methodology here is the same as for fossil fuel prices. In the short term to 2020 forward prices are used, and from 2020 to 2030 prices are projected to converge to the assumed 2030 level.

For the UK, CO_2 price assumptions are different. In 2013, the UK introduced a carbon price floor, aiming at ensuring a minimum CO_2 price of GBP 16/tCO_2 in 2013 and GBP 70/tCO_2 in 2030 (2009-prices). The system is implemented by adding a national tax on CO_2 (CPS, Carbon Price Support), which should cover the difference between the EU ETS price and the total target. However, in 2014 the UK introduced a cap on the national tax of GBP 18/tCO_2 for 2016–2019 to limit the difference between the EU ETS price and the total national CO_2-tax. Currently, no policies for such a cap beyond 2019 are in place, and in principal the CPS will rise again after 2019. However, in this report it is assumed that the national tax will be kept constant from 2019 and on, and thus the effective carbon price in the UK will follow the same tendency as in the rest of Europe but with an added tax. The main reason for this choice is an assumption that the increasing integration of the power systems in the UK and continental Europe makes it less likely that a large difference in the effective CO_2-price will be acceptable for power producers in international competition.

The respective CO_2 prices are shown in the figure below.

Figure 34: CO2 price given in EUR15/ton. On short run based on market forwards



Renewable capacity

The model has the option to invest in new capacity. In the near future, however, the modelling includes assumptions on the roll-out of capacity based on known investment plans and best estimates for the roll-out out of RE capacities from updated public sources. The following table lists the main sources for the short to medium term roll-out of RE-capacities, which have been included in the model.

Table 10: Main sources for the roll-out of RE generation capacity

	2020	2030
Denmark	Projections for wind and sun based on Energinet.dk's analysis assumptions that are based on existing policy and assumed future decisions. Minor change: a major offshore park replaced by solar cells to account for the price drop of solar cells in recent years. Converting coal to biomass based on known plans and model optimization.	
Sweden/Norway/Finland	Until 2025: ENTSO-E. SO&AF 2015. Scenario B. Model investments hereafter.	
Germany	Projections based on the law on renewable energy (EEG)[75]	Continuance of Energiewende. Scenario B of the first draft for the scenario frame for Netzentwicklungsplan 2015[76]
Great Britain	Until 2025: Projections based on ENTSO-E, SO&AF 2015, Scenario B (wind), and DECC's Updated Energy and Emissions projections report 2014 (solar PV and biomass). Model investments hereafter.	
Other countries	Until 2025: ENTSO-E. SO&AF 2015. Scenario B. Model investments hereafter.	

[75] German Federal Ministry for Economic Affairs and Energy (2014): *Gesetz für den Ausbau erneuerbarer Energien.*

[76] 50Hertz, Amprion, TenneT, TransnetBW (2014): *Szenariorahmen får die Netzentwicklungspläne Strom 2015 – Entwurf der Übertragungsnetzbetreiber*, April 2014, draft – not approved by the German regulator.

Figure 35: Installed generation capacity given in MW for the reference scenario

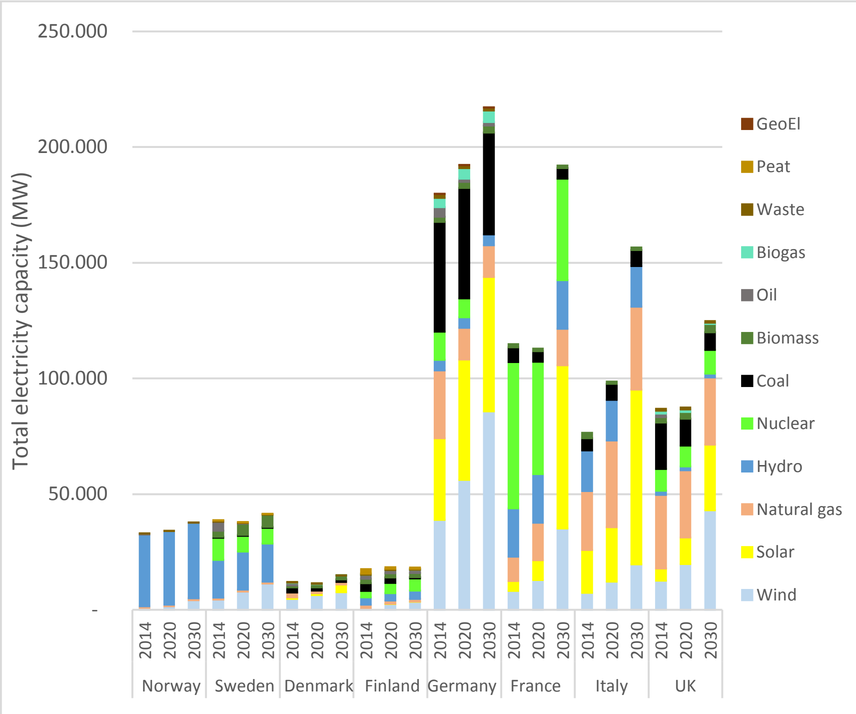
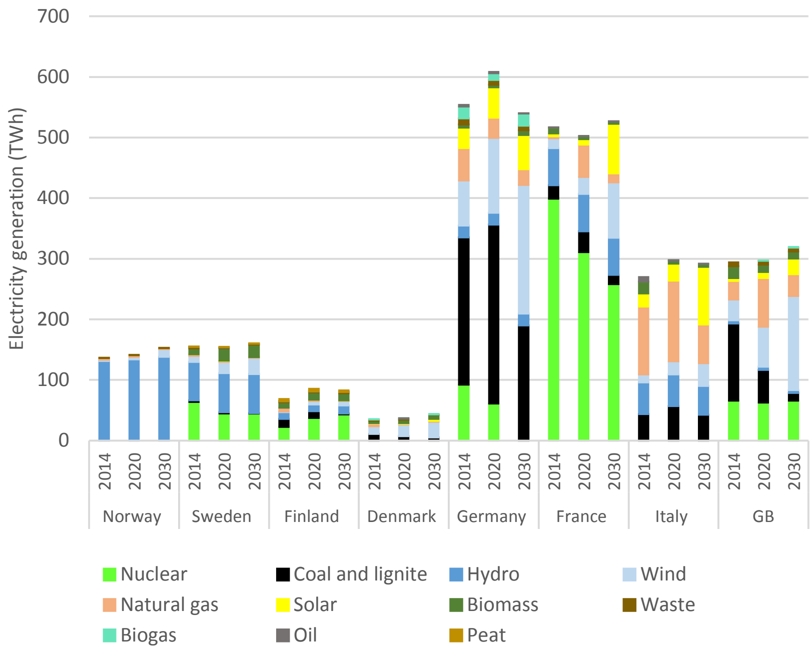


Figure 36: Electricity generation given in TWh for the reference scenario



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Regional Electricity Market Design

Do current electricity market designs ensure a sufficient electricity supply at all times? This topic is currently the subject of intense debate across Europe, and several major countries such as Germany, the UK, France and Italy have decided that additional measures – so-called capacity remuneration mechanisms – are needed to supplement current market designs. This report describes and analyses the advantages and disadvantages of a range of measures proposed or currently implemented across Europe, and includes both best estimates of how the implementation of these measures will impact Nordic electricity prices as well as recommendations to the Nordic countries regarding a cost-efficient path to ensuring the Nordic security of supply.

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