NVE

Hedging possibilities and the Forward Capacity Allocation Network Code

Do transmission rights have merit in the Nordic electricity market?

A report by EC Group

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Hedging possibilities and the Forward Capacity Allocation Network Code

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Sammendrag: EC Group har på oppdrag fra NVE utarbeidet en rapport om prissikringsmuligheter i det nordiske kraftmarkedet, og hvorvidt langsiktige transmisjonsrettigheter (LTR) kan gi en merverdi til det eksisterende finansielle markedet.
Rapporten konkluderer med at LTR i Norden vil være lite hensiktsmessig siden markedsaktørene i Norden hovedsakelig baserer sin prissikring på finansielle produkter med systemprisen som referansepris, og mener andre tiltak bør prioriteres i den grad det behøves.

Emneord: Prissikring kraftmarked, langsiktige transmisjonsrettigheter, finansielle produkter kraftmarked

Forward Capacity Allocation, price hedging, electricity market, cross-zonal hedging, long-term transmission rights

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Hedging possibilities and the forward capacity allocation network code

DO TRANSMISSION RIGHTS HAVE MERIT IN THE NORDIC ELECTRICITY MARKET?

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Preface

In April 2015, NVE (The Norwegian Water Resources and Energy Directorate) invited tenders for a study concerning *"Hedging possibilities and the Forward Capacity Allocation Network Code – Do Transmission Rights have merit in the Nordic electricity market?"*. EC Group teamed up with five professors in economics/finance and one PhD-student in finance, and was awarded the contract in May. The project specification from NVE is attached in the Appendix.

The report is a joint product after an interdisciplinary and intense process over four weeks. On behalf of all the authors I thank NVE for the opportunity to study and comment on an on-going process of shaping the regulation of the internal electricity market. On behalf of EC Group I thank all team members for their dedicated efforts and hard work.

Oslo, 19 June 2015

Jørgen Bjørndalen, project manager

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Executive summary

The current wording of the draft Forward Capacity Allocation (FCA) network code seems to indicate that missing markets for cross zonal hedging products hamper competition in the wholesale market, and that tradable LTTRs can be a reasonable fix. This report argues that there are some problematic aspects with this definition of the problem, and that the outlined requirement for TSOs to offer LTTRs fails to address the problem(s) properly.

Day-ahead and intra-day prices are determined by day-ahead and intra-day physical flows across and between price zones. The design of the market coupling and coupling of regions implies that the actual physical day-ahead and intra-day power flow is efficient and fully independent from any LTTRs. Thus, if there is a serious lack of competition in the short-term markets, there are more direct and efficient measures to mitigate (illegal) abuse of dominant positions than requiring TSOs to offer LTTRs. Further, one cannot expect contract opportunities in itself to improve competition in electricity markets, as shown by Murphy and Smeers (2012). Even if hedging instruments were perfectly available, there will be opportunities to exert market power in local wholesale physical electricity markets.

Requiring TSOs to offer LTTRs is a regulatory intervention. Any regulatory intervention should be designed to correct a market failure, and be based on a systematic evaluation of benefits versus costs. To require that LTTRs are available in every price zone would however be a very strong form of market intervention. It would also entail significant costs related to implementing and administrating the new system.

There can be many reasons for a missing market, one of them being insufficient demand for the products, or lower willingness to pay for hedging than the costs associated with issuing relevant contracts. If market participants choose not to hedge cross zonal price risk, this might actually indicate that the participants do not see this risk as an important factor in their daily activities, or that it is not worthwhile to accept the market based risk premium. The explanation could be small price differences, or that the zonal price is sufficiently correlated with the underlying for an alternative hedging instrument.

Nordic TSOs are regulated such that their incentives are independent of short-term profit or loss from congestion rent and the eventual sale of LTTRs. This implies that a requirement to sell LTTRs is not likely to change the TSOs behaviour with respect to setting cross border transmission capacities.

Requiring the Nordic TSOs to auction LTTRs will mean that market participants have to perform their hedging activities through two platforms and/or with two not fully compatible contracts. LTTRs are generally not very compatible with current Nordic hedging practice, as the underlying system price is without geographical reference. Introducing LTTRs imply a risk of significant loss of liquidity and increased hedging costs in this region.

An alternative to creating a new market based on LTTRs would be to create better hedging opportunities by supporting the markets for hedging tools that are already in place, for example to let the TSOs support some form of market maker service in order to increase liquidity.

1 Introduction

2 April 2014, ENTSO-E published the second edition of the network code on forward capacity allocation (FCA). Regarding the objective, article 33 (1) states that *"The forward capacity allocation shall enable long term cross zonal trade and provide market participants with long term cross zonal hedging opportunities against congestion costs and day ahead congestion pricing, compatible with bidding zone delimitation"*.

The draft FCA network code is developed in parallel with a network code on capacity allocation and congestion management (CACM). In ACER's guideline for developing the CACM network code, an initial impact assessment was presented. Here, ACER describes the objective of the CACM *"to ensure optimal use of the transmission network for cross-border trade, in support of the creation of one truly integrated, competitive and efficient European Internal Electricity Market."*

Together, the FCA and CACM codes represent the further development of older EU legislation and regulation aiming for a truly competitive electricity market. The current wording of the draft FCA network code (ENTSO-E 2014a) seems to indicate that missing or imperfect markets for cross zonal hedging products hamper competition in the European wholesale market for electricity. The rationale is to *"promote efficiency in cross-border transmission infrastructure, and to secure cross-border competition in power generation, mitigation of market power in generation, facilitation of investments in cross-border transmission capacity, risk allocation to TSOs, and accommodation of intermittent generation"* (Spodniak *et al*., 2014). The hypothesis is that cross-border trade will improve a situation of poor competition, and that appropriate hedging instruments for cross-border trade, such as long-term transmission rights (LTTRs) are essential to facilitate such trade.

Some TSOs have already offered LTTRs under various designs, conditions and platforms for many years, while other TSOs have never offered or stopped offering LTTRs. The draft FCA code *requires* TSOs to offer LTTRs covering all price zones unless forward financial electricity markets are well developed and efficient.

The reports, presentations, drafts, and other documents released during the processes leading up to these network codes (drafts) indicate a belief that requiring transmission system operators, TSOs, to offer LTTRs, will encourage these entities to make more efforts to avoid temporary reductions in transmission capacity between price zones when facing internal congestion and operational challenges.

Requiring TSOs to offer LTTRs is a regulatory intervention. Any regulatory intervention should be designed to correct a market failure, and be based on a systematic evaluation of

benefits versus costs. Regulatory intervention can only be justified if the expected benefits are higher than the associated costs (Coase, 1960). Both costs and benefits can be diverse, and are not necessarily easily translated into monetary terms. Financial costs are often the easiest to identify, due to the abundance of information available from market data. Benefits should not only include improvement in the form of financial profits, but also recognize choices that lead to increased welfare from a utilitarian perspective (Perman *et al.*, 2003). When the relevant costs and benefits are identified, it is important to determine which of the stakeholders will benefit from the alternative policies, and how the associated costs are covered.

Broadly speaking, the analytical approach employed in this study will be conducted in 5 steps:

1. Identify and define the problem
2. List alternative ways to solve the problem
3. Discuss the costs and benefits associated with the suggested fix
4. Regarding the stakeholders, discuss how the costs and benefits will be divided between the participants
5. Conclude on whether the suggested regulatory intervention seems reasonable or if alternative solutions appear more adequate

Steps 1 and 2 are discussed in chapter 3. In chapter 4 we proceed with assessing costs and benefits with the proposal of requiring TSOs to offer LTTRs, according to step 3 and 4. In chapter 5 we draw our conclusions. Before we proceed, we start with an overview of the wholesale market for electricity in chapter 2.

1.1 Abbreviations

It seems difficult to discuss the process of developing codes for the European electricity market without using the same vocabulary and the huge number of sector-specific abbreviations that are abundant in all draft codes and explanations we have seen. For the benefit of readers not utterly familiar with the tribal language in the electricity sector, we have set up a list of some of the most important abbreviations – in alphabetical order. Some of the abbreviations are also explained where relevant in the text.

Acronym	Interpretation
ACER	Agency For The Cooperation Of Energy Regulators
CACM	Capacity Allocation and Congestion Management
CfD	Contract for Difference
EPAD	Electricity Price Area Differential
ENTSO-E	European Network of Transmission System Operators for Electricity
FTR	Financial Transmission Right
LTTR	Long Term Transmission Right
PTR	Physical Transmission Right
TSO	Transmission System Operator

2 The wholesale market for electricity

The purpose of this chapter is to explain the fundamental structure of electricity trading and to show that the wholesale market for electricity is not dramatically different from most other commodity markets. Because this is the case, experience from other commodity markets is highly relevant in studying the core issue of this report: whether requiring TSOs to offer LTTRs will have merit in the Nordic electricity market.

We focus on the wholesale segment of the market, where producers, large end-users, retail agents, and traders are the participants. Households, SMEs, other 'minor' end-users, and relatively small producers, are typically represented in the wholesale market via retail agents or portfolio managers, and thus have no direct role in the wholesale market. We will ignore the transport from the wholesale market to the final end users. Transport within the wholesale market is, however, a core part of our study, as it is the transport costs and congestion (capacity limits) that give rise to price zones and the discussion about transmission rights.

2.1 Wholesale market participants and business models

The wholesale market for electricity is open for anyone who can generate or use power, connect to the grid and find counterparties willing to buy or sell. As in any other markets, and with any other commodities, you do not need to own any generation or serve end-users: individual traders can freely participate in the market, and buy and sell the product. The different types of wholesale market participants are listed below. Many participants combine two or more roles in one company.

Participant	Typical business model
• Producers	Generate power and optimise power plant operation
• Large end-users	Large-scale industrial production of goods or services; minimise energy costs by optimising a portfolio of electricity contracts and/or generation
• Retail agents/suppliers	Maximise profit by a combination of maximising consumer value and minimising purchase price of electricity for supply
• Traders	Make a profit by buying and selling power contracts/derivatives, either as a stand-alone business or as a support function for hedging purposes

As in most other markets, most end-users are not participating in the wholesale market. Instead, end-users choose among a range of suppliers. The suppliers buy power either directly from a producer or through a power exchange. The suppliers resell power to small and medium-sized companies and households. The physical transportation to the end-users is taken care of by network (grid) companies. Most of these activities are outside the scope of our study. However, the demand side's preferences for price stability affect or determine, the retail agents' demand for hedging in the wholesale market.

In addition to the market participants, other 'agents' have important roles in the wholesale market. In the Nordic wholesale power market, Nord Pool Spot plays a vital role in coordinating the supply and demand, as this is the key market place for wholesale power at the day-ahead stage. Most market participants (wholesale) make use of the day-ahead power exchange for selling or buying their residual demand.[1,2] They do this by submitting bids to buy or sell power at specified prices and in specified price zone(s) for one or more of the 24 hours the following day. Similar arrangements exist in most European power markets, with some minor, but in our context hardly relevant differences in the setup of the day-ahead power exchanges. Other power exchanges for day-ahead are EPEX SPOT (Germany, France, Austria and Switzerland), APX (Belgium, the Netherlands and the United Kingdom), OMEL (Spain and Portugal) – any European country is served by at least one power exchange for day-ahead trade. The outcome of the day-ahead auctions is legally binding obligations to supply or off-take an amount of power (MWh/h) for one or more of the 24 hours the following day, as well as the prices that clears each of the zones.

The TSOs 'facilitate' the day-ahead market. Their tasks include defining the price zone limits and the available network capacity for the market.[3] When there are grid constraints

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[1] Residual demand is generation plus contracted purchases minus contracted sales and supplies to end-users.
[2] In fact, most vertically integrated power companies in the Nordic region sell all generation at Nord Pool Spot, and buy all energy required for the supply of their customers at Nord Pool Spot, which means the trade at Nord Pool Spot is closer to gross demand than net demand of all suppliers.
[3] Europe is currently in the midst of a process of implementing flow-based market coupling, replacing a net ("available") transmission capacity approach. Flow-based market coupling is technically a different approach for the day-ahead exchanges to find the optimal utilization of all bids and asks in the day-ahead market. The key change is to account for the fact that transmission capacities in an electricity network, within and across zones, are essentially endogenous dynamic entities, not well represented via exogenous static parameters. The transition impacts how much electricity can be transferred with a given set of interconnection lines while still respecting standard security constraints. It does not, however, impact the functionality of the wholesale market in any other ways.

inside a price zone, the TSO will take measures to ensure a stable grid operation, e.g. by counter-trading the positions established in the day-ahead market.[4]

Market participants wanting to contract further ahead than one day, can find a counterpart themselves, ask a broker for assistance, or find a counterpart at exchanges or OTC-brokers. Nasdaq, EEX, ICAP Energy and GFI are some of the European market places quoting electricity futures, forwards and options with different durations and specifications, and for different countries. Some of the intermediaries, e.g. Nasdaq, also offer clearing services.

2.2 The risks depend on the business model(s)

The electricity market participants face a number of different risks. The importance of each risk factor varies between market participants, depending on among other things their business models, their asset portfolio, and their ownership and organisational structure. Some of the risks are normally hedged or mitigated in one way or the other, whereas other risks typically remain unhedged.

Type of risk	Explanation
Price risk (market prices)	Electricity prices vary over time and location. Day-ahead prices are set for each hour. There is uncertainty with respect to each hourly price, the shape of the price curve for each day, the daily or yearly average price level, as well as the price difference between areas (zones). For the market participants, the hourly price in any zone can be understood as a stochastic variable. The price risk is the risk that the price(s) turns out different than expected.
Volume risk (market participant's volume)	Both demand and generation volumes are uncertain. End users can use more or less than forecasted. Most renewable power sources, such as hydropower, PV, and wind, have their energy production and timing determined by nature, not by planning. The volume risk is the risk that the supply or demand volumes are different from forecasts.

[4] Internal congestions are fairly common. Some are caused by temporary transmission shortages, e.g. due to maintenance, failure of critical components, etc., whereas others are more permanent (until new capacity is built) e.g. due to relatively high growth of supply (or demand) in one region, like in the northern part of Germany.

Profile risk (the combination of volume and price risk for a market participant)	Neither consumption nor non-controllable generation is stable at a flat power rate (MW) during the day or the year. The profile risk is the risk that the load or generation profile differs from the expected or hedged pattern. It results in a volume-weighted average price that is different from the expected or hedged level.
Exchange rate risk	The Nordic market for long-term contracts is settled in EUR/MWh. In the day-ahead market, the market participants can choose settlement in Euro or local currency, while most other costs and revenues for market participants are in local currencies. The typical exchange rate risk is the risk that the Euro-rate changes the value of the long-term hedge.
Operation risk	The operational risks are the risks that errors are made or failures affect the daily operations of the market participant. Risks are minimised by developing good routines, maintaining double IT-systems, etc.
Technical risk	Power plants and consumption assets can fail. Technical risks are generally minimised by good maintenance procedures.
Manpower risk	People can fail, get ill or be disloyal. Utilities can be hit by strikes.
Credit risk	Counterparts can fail to cover their obligations. Clearing of power contracts is a common method to control or minimise the counterpart risk associated with hedging instruments.
Legal risks	The legal risk is the risk that contracts etc. are different from what was anticipated
Political risk	Political changes regarding climate or energy policy can have a tremendous impact on wholesale market participants.

We need to elaborate a bit further on the price risks for various business models in the wholesale market. First, we consider a producer with power plants in one or more price zones, say A and B. The power plants in zone A are exposed to the price level and price variation in zone A, while power plants in B are exposed to prices in zone B. *None of these are exposed to the price difference between A and B.* If there are liquid and well-functioning forward markets in both zones, the state of the art hedging strategy will be based on selling forward contracts (creating short positions) in both zones, corresponding to the planned volumes in each zone and adjusted for risk preferences. If the forward market in B is inefficient, non-competitive, or 'inferior' in any other way, an alternative hedging strategy for the assets in B would be to sell additional contracts in A and buy a long-term transmission right from A to B (see also section 2.3.2 for further explanation of transmission rights). If the day-ahead prices in A and B are sufficiently correlated, a third

option will also be considered: Not hedge the price difference between A and B, but simply rely on hedging everything in A.

Correspondingly, an end-user or a supplier with demand in both A and B would typically make use of similar hedging instruments, i.e. buy forward contracts in A and B respectively, or alternatively in A, possibly also combined with transmission rights from A to B.

Now let us consider a utility with generation in A and sales in B. This business model is indeed exposed to the difference between the price levels in A and B. However, if there are liquid and well-functioning forward markets in both zones, the state of the art hedging strategy will be based on selling forward contracts (creating short positions) in A, and buying forwards in zone B. Transmission rights between A and B will only be considered if one of the 'local' forward markets is inefficient.[5]

2.3 What are the available and liquid hedging instruments?

Market participants demand long-term contracts of different types and details in order to eliminate (hedge) the risks of concern. The supply and demand of such long-term contracts depends on the risk preferences of market participants, market- and commodity-specific characteristics, market- and institutional design, and regulatory framework. Economic features of markets for long-term contracts are generally comparable across commodities and jurisdictions. An important difference, though, is that electricity is not a storable commodity.

2.3.1 The Nordic system price and EPADs

In the Nordic wholesale market for electricity, the physical deliveries resulting from the day-ahead auctions at Nord Pool Spot are settled at *the area price* in the relevant *price zone*.[6] Market participants typically hedge their price risks by building short or long positions in system price contracts.

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[5] Recall that the utility is facing a known generation cost in A and a known sales-price in B. By selling forwards in A the generation profit is hedged, and by buying forwards in B the sales profit is hedged. Then it doesn't matter what the transmission costs are – it even doesn't matter if transmission is possible at all times. But if one of these hedges is impossible or very hard to get, the alternative hedging strategy would be to try replacing one of them with an LTTR.

[6] Currently, there are five price zones, and hence five area prices, in Norway. Sweden consists of four zones, Denmark of two zones, while Finland is one zone. In addition, Estonia and Latvia are also represented as individual zones. Quite often the prices are equal in a number of zones, but they are rarely the same in all zones.

The system price is calculated as an intermediate step of the day-ahead auctions at Nord Pool Spot, has no geographical reference, and is not applied for physical deliveries. The Nordic system price is calculated as the hypothetical clearing price of all bids and asks in the day-ahead market if there were no constraints in the transmission network.

As constraints between the zones are indeed normal[7], the area prices generally differ from each other and from the system price. A hedge based on system price derivatives is therefore not perfect in the theoretical sense. An important part of the remaining basis risk is thus hedged by building short or long positions in EPADs (Electricity Price Area Differential). However, a number of market participants leave the area price risk unhedged, as they find the correlation between the system price and the area price sufficient.

EPADs are financial contracts for differences between the system price and the relevant area price (and until a few years ago, they were also traded under the name CfD). EPADs are listed at Nasdaq for two of the Norwegian price areas, all four Swedish zones, both Danish, as well as for Finland, Estonia and Latvia. The durations of listed EPADs differ slightly between regions. The total diversity of available EPADs reflects the diversity in demand for hedging instruments, with respect to both geography and duration.

The payoff for an EPAD is the local area price minus the system price. Hence the EPADs are comparable with FTR obligations, except an EPAD is not between two interconnected areas but rather between one area and the system price. In order to offset the risk in the price difference across zones, one thus has to buy/sell two EPADs.

While a large proportion of the trade in Nordic system price contracts takes place at Nasdaq, a lot of the trade in EPADs is OTC. However, most of the OTC trade is cleared through Nasdaq, which means key information like open interest, price volatility of the various contracts etc. is fairly transparent. In 2014, the total turnover in all contracts was 1500 TWh, which is almost four times the fundamental market volume (approximately 400 TWh). As both the price level and price volatility have decreased over recent years, the traded volumes have dropped from an all-time high in 2008 at 2500 TWh. 58 % of the 2014 volume was traded via Nasdaq; the remaining volume was OTC. EPADs accounted for approximately 9 % of the cleared volume in 2014.[8]

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[7] In fact, the price zones are generally defined to reflect the major congestions in the transmission system.
[8] All figures are courtesy of Nasdaq's presentation at the Fingrid Market Day, April 28, 2015.

2.3.2 Transmission rights

LTTRs can be physical or financial transmission rights. A physical transmission right (PTR) gives the holder an exclusive right to transfer a quantity of energy in one direction from one zone to the other. PTRs can be used to buy or sell power in OTC markets, through power exchanges or to meet physical positions in the two markets. In the FCA network code, PTRs are defined as options subject to Use-It-Or-Sell-It (UIOSI) mechanisms, which ensures that not-nominated capacity automatically gets sold in the day-ahead market. PTRs must therefore be nominated daily, in due time before the day-ahead auction at noon.

This implies that if a PTR is utilised (nominated) from a high price to a low price zone, the effect will be increased trading capacity in the day-ahead market in the other, profitable direction.[9] European PTRs will consequently have *no impact on the actual, physical day-ahead trading* between price zones. The UIOSI-rules further ensure that European PTRs are essentially financial instruments.[10]

FTRs are purely financial instruments, and do not entitle the holder to physically transfer power between price zones. There are several possible definitions of FTRs, each with its advantages and disadvantages. One such defining feature is whether the FTR is an option or an obligation; see the example below. From the perspective of a market participant seeking to hedge a physical position, there are some important differences between the two designs. With an FTR obligation, the holder of the transmission right is fully hedged in a bilateral transaction, as any payoff from the financial contract will offset a corresponding position in the physical market. With an FTR option, the cash flow from the financial contract will not balance the position in the physical market. The bilateral transaction would be hedged, and additional opportunities to collect revenue from price differences would occur.

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[9] Assume the capacity between A and B is Q MW in both directions. A nomination of x MW PTR from A to B implies that for the day-ahead market, other market participants can only trade Q-x from A to B. However, in the opposite direction, it will now be possible to trade Q+x. If the profitable direction is from A to B, the market coupling and price coupling of markets will ensure that the flow from A to B is Q. And if the profitable direction is from B to A (and the nomination turned out to be unprofitable for the PTR owner), the day-ahead flow will still be Q – from B to A. The coupling will offset the unprofitable nomination. (This explanation implicitly assumes the price differences between A and B are not too small.)
[10] For the Danish-German border, PTRs are no longer nominated – all buyers of PTRs simply receive the financial settlement induced by the UIOSI principle. Source: Market info at www.energinet.dk.

It is important to understand the behaviour of the different LTTR designs. Using a simplified example, we can highlight the key issue. The example has two cases, each consisting of three periods. In case 1, the average price in A equals the average price in B, while in case 2 the average price in B is higher than the average price in A. We study all three types of LTTRs in both directions, i.e. six different contracts.

Note: All values are EUR/MWh						Payoff for contract from A to B			Payoff for contract from B to A		
	Period	Price A	Price B	Difference, B minus A	Congestion revenue	PTR w/UIOSI	FTR Option	FTR Obligation	PTR w/UIOSI	FTR Option	FTR Obligation
Case 1	1	20	33	13	13	13	13	13	0	0	-13
	2	20	20	0	0	0	0	0	0	0	0
	3	20	7	-13	13	0	0	-13	13	13	13
Average price or payofl		**20**	**20**	**0**	**8,67**	**4,33**	**4,33**	**0**	**4,33**	**4,33**	**0**
Accumulated payoff					**26**	**13**	**13**	**0**	**13**	**13**	**0**
Case 2	1	20	26	6	6	6	6	6	0	0	-6
	2	20	27	7	7	7	7	7	0	0	-7
	3	20	25	5	5	5	5	5	0	0	-5
Average price or payofl		**20**	**26**	**6**	**6**	**6**	**6**	**6**	**0**	**0**	**-6**
Accumulated payoff					**18**	**18**	**18**	**18**	**0**	**0**	**-18**

Exhibit 2-1 Simplified example

The payoffs for the FTR obligations are exactly equal to the differences between the average prices. From case 2, we can immediately see that direction matters. Looking at case 1, one can also find that as long as the averages of the zonal prices are equal, the payoff for FTR obligations is independent of the volatility of each zonal price: change the prices in A to 10, 20 and 30 – the average is still 20, and the payoff for the obligation is still zero. This can also be deduced from a comparison of both cases – the payoff for the obligation is equal to the difference, irrespective of the variation in prices within each zone. This implies that for business models where base load[11] contracts are normally used for hedging, FTR obligations could be a relevant alternative to a local base load contract.

For FTR options and PTRs with UIOSI matters are more complicated. The payoff for these contracts can be described as the average of the positive hourly price differences. The key point is that the average of the positive price differences is not the same as the difference between the average prices. Even if the average prices are equal, the payoff is high – in both directions.[12] Comparing the volatility of prices in B in both cases, we can also see an indication that the payoff for the FTR option is driven by volatility. In this example, it

[11] A base load contract has a constant volume; the same energy volume for all hours for the duration of the contract. The alternative is peak load, which is typically between 08:00 and 20:00 Monday to Friday for the duration of the contract.
[12] Here payoffs are also the same in each direction because we defined prices in B that are symmetric around the average.

appears to be the volatility of the prices in B. The accumulated payoffs provide further indication of the role of volatility. In reality, it is the volatility of the price difference (per hour) plus the difference between the average prices that drives the payoff for FTR options and PTRs with UIOSI (see also Newbery, 2004). In fact, the payoff for a PTR or an FTR option is uncorrelated with the average (or accumulated) price difference. Consequently, such contracts are not very efficient hedging instruments for market business models exposed to the difference in average prices in two (or more) regions.

2.3.3 A small note on transmission rights in the US

The electric power sector in the US was, prior to the restructuring, characterized by strong vertically integrated utilities, merchant interconnecting lines, and long-term bilateral contracts in highly meshed grids with complex loop flows. Congestion Revenue Rights were introduced as an important component of the Standard Market Design by the FERC (Federal Energy Regulatory Commission). Point-to-point Financial Transmission Rights (FTRs) (Hogan, 1992) are rights to congestion revenues. Allocation of FTRs is either on the basis of historical entitlements or through auctions, or in a combination of these two (Deng *et al.*, 2010). A number of FTRs are grandfathered to actual grid owners, and other market participants. They are essentially entitlements to the congestion rents (but also hedging instruments).

The market design with locational marginal prices found in most regions in the US is fundamentally different from the European market design with uniform zonal prices. The use of locational marginal prices (LMP) (Schweppe et al., 1988) is primarily for managing transmission constraints within a market. Market coupling, or splitting, as used in Europe, integrates the markets for transmission capacity with the day-ahead market for electricity resulting in efficient cross-border flows.

Consequently, literature about FTRs and PTRs in the US must be read with great care if the purpose is to analyse European market design.

2.4 End users absorb some of the price risks

To the extent end-users accept price variations, they implicitly offer hedging to their suppliers. Consider a supplier with customers in zone A and B. One strategy, or business model, would be to offer all end-users the same price, fixed for a ‘long’ period (more than one day), irrespective of their location in A or B. Such suppliers can be exposed to the price difference between A and B, depending on how they choose to hedge their purchases in the wholesale market in A and B.

Alternative strategies can be based on not offering a fixed and equal price to all customers. If long-term contracts with reference to area B are costly (come with a high risk premium) or are unavailable, customers in B could be offered contracts with variable prices, such as a price formula depending on the local day-ahead price in area B.

Furthermore, a producer in area B, who might find it difficult to hedge his generation in that area, could invest in a supplier serving customers in area B, in an attempt to reduce the impact of price fluctuations in area B.

The extent to which such alternative strategies are available or feasible varies from country to country, depending on domestic regulation of end-user markets, regulatory 'tradition', political context, etc. In Norway, more than two thirds of the households and SMEs prefer supply contracts where the price is a linear function of the area price. The suppliers of such customers would *increase* their price risk if they started buying EPADs and system price derivatives.

In Denmark, the situation is different, as there is no tradition for contracts with 'floating' prices. Typically, end-users prefer contracts where the price is fixed for a period, or can be changed only after an agreed warning period. The supply to such end-users will typically result in the supplier demanding EPADs and system price contracts.

The key point is that one cannot ignore the nature of the end-user market in the region when analysing the available hedging opportunities in the wholesale market.

3 Problem definition and potential solutions

The proposed requirements on TSOs to offer LTTRs is intended to help improve competition in the wholesale power market by increasing the availability of hedging instruments for cross zonal price risks. It is further regarded as important to incentivise TSOs to not curtail cross zonal capacity to mitigate the consequences of any internal congestion.

The purpose of this chapter is 1) to explore the fundamental problem (improving competition) in some detail, and 2) briefly and more generally, discuss what alternative solutions are available to mitigate the problem.

3.1 Identification and definition of problem

The main subject of this study is the pan-European electricity market, with particular attention to the Nordic electricity market. According to standard economic theory, a market is considered well functioning if it is competitive and efficient. The following properties are generally considered important for such a market to exist (Belleflamme and Peitz, 2010):

- Neither buyers nor sellers have market power due to collusion or monopolization. The existence of monopoly power in a market restricts the opportunities of smaller competitors and potential new market entrants.
- Entry/exit costs are low. Barriers to entry, like very large investment requirements or restrictive licences reduce the possibilities of new parties entering the market. High exit costs increase the risk of entering the market.
- Information relevant for price formation should be available at a low cost to all market participants (von der Fehr, 2013. All parties in the market, including firms and consumers, must be well informed in order to make efficient decisions.
- There should be no market externalities, i.e. benefits or costs not recognized in the market supply and demand.

From a practical viewpoint, few markets satisfy all of the conditions outlined above. Market failure occurs when one or more of the conditions are violated in a substantial way. In some sectors of the economy, the market imperfections are minor. In others, governments examine the type and significance of the market failure, and evaluate the need for market intervention to improve the efficiency of these markets. From a competition policy perspective, the role of the government is to avoid situations with monopolistic markets (Belleflamme and Peitz, 2010). Further, the regulation authorities should attempt to keep transactions fees such as taxes, regulatory requirements and legal fees sufficiently low, to avoid entry barriers.

In a historical perspective, large and oligopolistic producers have characterized European power markets. Power production and distribution has been considered a sector where competitive and well-functioning markets would be difficult to achieve, due to inherent industry characteristics and public interest objectives:

- First and foremost, the supply of electricity is important from a public interest viewpoint. Securing the supply of electricity, and the associated services related to managing this flow, is central in a social welfare perspective. In that regard, it is worth mentioning that all components of the power grid are interdependent; a single co-ordinated network is necessary to provide a stable flow to end-users. Component failure may sometimes lead to blackouts that affect many other than the component owner.
- Further, the users of the network must be able to utilize public resources that are not readily obtainable in a competitive market. The use of the transmission and distribution network itself is a fitting example of such a resource.
- There are also significant barriers to entry in the wholesale power markets. Investment requirements in this sector are very high, and operating a power grid entails high fixed costs and significant economies of scale. These factors explain why generation, transmission and distribution of electricity for a long time typically was vertically integrated into state-owned or state-controlled utilities, with each region or country effectively managing electricity as a public good.

Technology improvements and a new political climate were in many ways the catalysts of the deregulation process in European power markets, a process that started in the late 1980s and early 1990s. Today, the focus is on promoting competition and efficiency in the European electricity market. There are two relevant dimensions in this respect: the short-term (day-ahead and intra-day) power flow between zones and the long-term hedging opportunities. The current wording of the draft FCA network code seems to indicate that availability of appropriate hedging instruments for cross zonal price risk is crucial to improve a situation of insufficient competition in the electricity markets of a number of European countries.

This brings us back to the concept of cost-benefit analysis that was introduced in chapter 1. The current wording of the draft FCA network code seems to indicate that missing markets for cross zonal hedging products hamper competition in the wholesale market, and that tradable LTTRs can be a reasonable fix. We believe there are some problematic aspects with this definition of the problem:

- First, oligopolistic market structures generally do not foster competitive efficiency, and we have already mentioned that large and oligopolistic producers characterise European electricity markets. Even if hedging instruments were perfectly available, there will be opportunities to exert market power in the local wholesale physical electricity markets.

- With the current European market design, in particular the rules for congestion management and coupling of the day-ahead, ownership to transmission rights can only have an indirect impact on the determination of the short-term prices. Day-ahead and intra-day prices are determined by day-ahead and intra-day physical flows across and between price zones. Thus, if there is a serious lack of competition in the short-term markets, there are more direct and efficient measures to mitigate (illegal) abuse of dominant positions than requiring TSOs to offer LTTRs. Such measures include expanding the capacity of the network, or regulatory measures directed towards the oligopolistic market participants (e.g. requiring them to offer virtual power plants in the concerned zones[13]).
- Relevant literature on the interaction between contracts and competition discusses whether the impact of the presence of contracts will improve efficiency. The suspected mechanism is that the presence of contracts will entice oligopolistic producers to commit production through contracting in a way that leads to competitive outcomes in the physical day-ahead market (Allaz and Vila, 1993). However, as shown by Murphy and Smeers (2012), one cannot expect contract opportunities in itself to improve competition in electricity markets. They write "*...regulators or competition authorities cannot rely on contracts to induce sufficient capacity expansion by reducing market power*". In fact, one might fear that large companies use their informational advantages to manipulate financial prices in ways that are detrimental to competitive efficiency (Munthe *et al.*, 2007). See also Le Coq and Orzen (2006).

- Second, there can be many reasons for a missing market, one of them being insufficient demand for the products, or lower willingness to pay for hedging than the costs associated with issuing relevant contracts. If market participants choose not to hedge cross zonal price risk, this might actually indicate that the participants do not see this risk as an important factor in their daily activities, or that it is not worthwhile to accept the market based risk premium. One explanation could be that the zonal price is sufficiently correlated with the underlying for an alternative hedging instrument. Bjørndalen and Naper (2013) provide some evidence in this regard, as they show that market prices for LTTRs are systematically below the ex post value, i.e. the risk premium associated with these contracts is always negative. This indicates that LTTRs are generally not in high demand as hedging instruments, and that the hedging value of long-term transmission rights is doubtful.

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[13] In Case N° COMP/M.1853 EDF/EnBW in 2001, the European Commission ruled that by acquiring effective control of EnBW, EDF had a dominant position in Bavaria. To remedy the situation EDF agreed (1) to renounce its voting in the French hydroproducer CNR and (2) to provide access to 5000MW of generation capacity in France to competitors via virtual power plants VPPs through auctions for the next 10 years.

- We also note that in the Nordic market, where cross zonal price risk can be hedged with purely financial contracts called EPADs, these contracts represent 9 % of total cleared volume in 2014. The historical figure has been in the range of 6.5-9 % (2008-2014)[14]. While many market participants are requesting increased liquidity in the EPAD market, it also appears as if many of the market players believe that derivatives on the system price are sufficient for their hedging purposes. The relatively low trading volume in EPAD contracts might indicate that cross zonal price uncertainty is not considered an important part of the risk paradigm in the Nordic power market.
    - Spodniak *et al.* (2014) takes the convergence and relationship between the spot and forward market as a measure of efficiency, and find that the Nordic market for EPADs appears efficient, with a possible exception for 2 price zones (out of 10). The authors further explain the fluctuating risk premium in EPADs by varying hedging needs, due to the share of fixed price contracts that the end customers have, and differences in production. The need to hedge might be different in areas with much hydro capacity (low volatility in prices), and vary with the level of hydro reservoirs. Local characteristics in production also seem to explain the high volatility and mainly positive risk premium in Danish EPADs (in particular DK1), where a significant part of power production originates from wind power.

Generally speaking, it is difficult to accurately determine whether there is an unsatisfied demand for hedging instruments, in particular for Nordic price areas and borders between the Nordic areas and the rest of Europe. One standard way to determine whether a market is efficient is to consider the correlation between the futures price and the underlying, or in the case of electricity, the correlation between the underlying price (for the available hedging instrument) and the day-ahead price for the area in question. One could also examine market indicators like trading volume, open interest and the bid-ask spread. The latter would of course require that most of the trade take place at regulated exchanges rather than at OTC brokers, as OTC trading generally is less transparent. As Nasdaq's market share in EPADs is relatively low, tests requiring market information are likely to be inaccurate. Similarly, the high OTC market share for forward trading in Continental power markets makes it complicated to rely on tests requiring huge transparency of market data.

To conclude, we are not convinced there really is a missing or imperfect market for cross zonal hedging products in the Nordic region and adjacent markets. This is essentially an empirical question that regulators should answer before requiring interventions in the market. Further, we are indeed convinced that problems of insufficient competition in zonal

[14] All figures are courtesy of Nasdaq's presentation at the Fingrid Market Day, April 28, 2015.

day-ahead markets cannot be mitigated by regulatory interventions in the market for hedging cross zonal price differences. The design of the market coupling and coupling of regions implies that the actual physical day-ahead and intra-day power flow is efficient and fully independent from any LTTRs.

3.2 Potential and alternative solutions

Although the above discussion shows that LTTRs play no role in mitigating market power and a limited role as hedging products, we continue the analysis by asking what measures could potentially fix a problem of unsatisfied demand for cross zonal hedging products. Also, we briefly discuss potential measures at increasing competition within a price zone.

If there truly is a missing market for hedging cross-border trades, requiring TSOs to offer LTTRs can indeed provide an alternative hedging possibility – allowing for a combination of a 'foreign' contract and an LTTR covering the difference between the foreign market and the 'transport' between the markets. To 'unify' the European electricity market and require that LTTRs are available in every price zone would however be a very strong form of market intervention. It would also entail significant costs related to implementing and administrating the new system. Finally, it would also imply only one price area with strong liquidity in the local forward and a number of less liquid LTTRs.[15]

An alternative to creating a new market based on LTTRs would be to support the markets for hedging tools that are already in place. In Hagman and Bjørndalen (2011), nine stakeholders in the Nordic electricity market were interviewed about their views on cross zonal hedging, but there seemed to be limited interest in FTRs as a hedging product. Two stakeholders stated that FTRs would give a better hedge if production in one area were sold to a customer in another area. However, no interviewed market player wanted a reduced liquidity in the CfDs, now the EPADs. Instead, all interviewed parties would welcome increased liquidity in these products.[16] Two ways to achieve this were suggested:

1. TSOs could commit to offer EPADs via auctions. The purpose would be to add additional supply of EPADs to the existing trade among market participants.

[15] Assume area A was the starting point for all hedging. Positions in B and C would be hedged by a combination of contracts with the price in A as underlying and LTTRs between A and B or C – but no direct trading in derivatives of B or C. Then forward contracts for A would have higher liquidity than LTTRs for A-B and A-C.
[16] At a NordREG conference in Stockholm 20 April 2015, the vast majority of participants confirmed this. Very few were interested in LTTRs for the Nordic region.

2. The TSOs could pay for a market maker service in the EPAD market, and justify the expenses, as this would potentially benefit all market participants. The market maker could be a trading house or the trading department of a generator.

The Nordic TSOs could, in principle, offer EPADs for all Nordic price areas, as suggested by Nordic market participants. However, and unlike the case of FTRs, that would imply accepting financial obligations that would not necessarily be matched by congestion revenues and revenues from the sale of the EPADs. In that regard, it is worth mentioning that one can easily create a synthetic FTR obligation by simultaneously buying and selling EPADs in two different price zones (EPAD combo).

Regarding the second point, market makers are regarded as a necessity to create liquidity, transparency and a well-functioning market with sound competition, benefiting the market as a whole. While the TSOs could participate directly in the market as market makers for EPADs, it seems more reasonable for these entities to support some form of market maker service. Such an approach was used successfully in the market for dairy futures at the Coffee, Sugar and Cocoa Exchange (CSCE – later part of the New York Board of Trade) in the mid-1990s. To promote liquidity in the new and immature market, the exchange gave floor traders already active in other markets on the exchange a cash endowment to act as market makers for dairy futures. In return, the traders were obligated to enter the open out-cry pit for dairy and offer both a bid and ask. Any profits from trading were kept by the traders and if net losses were generated they were deducted from the traders' initial endowments. If the entire endowment were lost then the trader was not responsible for the loss, but no further subsidization of his/her trading was to occur. More recently, several exchanges have developed Market Maker Programs focused on guaranteeing that a minimum bid/ask spread is available to market participants. These include the Chicago Mercantile Exchange (for both ethanol and weather futures contracts), the New York Board of Trade for equity index futures, and the ICE Futures Europe for their WTI contract. In contrast to the early CSCE program, the more recent programs do not provide a direct trading endowment, but in general reduce transactions costs for market maker participants to near $ 0 by waiving all exchange fees up to a pre-defined limit. In the case of the Chicago Mercantile Exchange program for ethanol, the market makers faced $ 0 exchange fees for trading both ethanol and corn futures (the primary input in U.S. ethanol production).

Nasdaq has some partly successful experiences with favourable conditions for market makers for EPADs, but not to a degree where all concerns for availability and liquidity have disappeared. Currently, Nasdaq has market makers in the Danish, Swedish and Finnish EPADs but none for the Norwegian EPADs. As a market facilitator Nasdaq can only offer

beneficial terms for market markers in the form of low trading and clearing fees. Given the low transaction volume in some EPADs, Nasdaq has not been able to attract market makers on these terms because they are not sufficient to compensate for the liquidity and price risk inherent in these products. They have so far concluded that a substantial increase in compensation is required to attract market makers providing a competitive bid ask spread and thereby creating a well-functioning liquid market for the remaining EPADs.

To what extent market making will mitigate a problem of undersupply of hedging instruments is an open, empirical question. Clearly, market makers have costs (like risk) in their function. If external parties, like TSOs or exchanges, reimburse such costs, the supply of market making is likely to increase, and the impact on the market for hedging is positive.

If, however, the fundamental problem is insufficient supply of power relative to demand, i.e. that an area is short of supply and/or suppliers, the availability of hedging instruments is not a very precise solution, as discussed in section 3.1 above. Then more direct measures than participating in trading activities in order to influence the competitive performance of day-ahead markets and the cross border flow of electricity should be considered. One obvious way would be to increase the investments in cross border capacities. It would also be possible to impact the power markets by decreasing the number of price zones across Europe, yet this would not solve the underlying problem of insufficient competition in areas with limited transmission capacity with other areas. It could in fact be argued that a larger price zone only increases the opportunities for abuse of dominant positions.[17] A third, and fundamentally different approach would be to require oligopolistic market participants to offer virtual power plants within the zone(s) subject to imperfect competition.

[17] The argument would be that congestions in the transmission system do not disappear only because TSOs decide that prices should be equal in a larger area. The only direct effect, in addition to equal prices across zones, is that congestions must be alleviated in less transparent markets and manners, such as countertrading.

4 Benefits and costs with current proposal

The purpose of this chapter is to explore the benefits and costs associated with the proposal of requiring TSOs to offer LTTRs between all price zones. We start with a short analysis of firmness conditions and the potential impact on TSO behaviour, relating to facilitating the utilisation of the transmission system. We proceed with discussing the benefits with regards to mitigating poor competition and to what extent the benefits, with regards to competition and improvement of hedging opportunities, depend on whether the LTTRs are options or obligations, physical or financial. Another important feature of LTTRs is the time horizon of available contracts. Then there are of course some operational costs if TSOs are supposed to arrange for market participants' hedging practices. Finally, as there already is a market in the Nordic region that serves the same purpose that LTTRs are supposed to attend to, we to discuss the costs of establishing and maintaining two parallel systems.

4.1 TSOs – firmness, regulation and incentives

Curtailment of transmission capacity can happen for several reasons (such as faults or maintenance on the grid etc.), but the cost of curtailment is ultimately a cost to the market. The key question is how this cost can be kept as low as possible, and how it should be attributed to the different stakeholders in the market. A hypothesis is that requiring TSOs to offer LTTRs will encourage these entities to make an effort to avoid reductions in available transmission capacity between price zones. The purpose of this section is to describe how possible incentive effects from introduction of LTTRs in the Nordic market depend on the regulatory setup in individual countries. The vision of encouraging competition in the European market and making TSOs behave in accordance with some market stimulus may not be as straight-forward as one might think.

Firm transmission rights, in the sense that a contract yields at least the financial benefit it is supposed to, even if the physical transmission is reduced for any reason, will be more attractive in the eyes of a market participant or financial investor, all else constant. This is accounted for in the firmness rules of the FCA network code.

If TSOs are unable to collect the congestion rents matching their obligations towards LTTR buyers, they face firmness risk. Reimbursements to LTTR holders will need to be financed. If the costs of reimbursements are transferred onto customers through tariffs, the costs will be socialised, and hence be irrelevant in the decision making process of the TSOs.

However, the costs are still the same in monetary value; the only difference being that different stakeholders foot the bill.

A key issue here is the degree of exogeneity in the determination of the TSO's revenue. If increased costs are compensated through the revenue regulation, there is no reason to expect that a requirement to offer LTTRs will make a TSO less likely to curtail cross zonal transmission capacity in situations with congestion internally in one or more price zones. Moreover, if a TSO after all is incentivised, it is not necessarily, or solely, in the sense that the TSO will avoid curtailment of cross zonal capacity. One might actually fear that in the short run, the TSO will jeopardize security of supply and nominate as much capacity as possible despite eventual internal challenges. The deciding factor will be which has the strongest financial impact on the TSO – curtailment or reduced security of supply. Further, a long run incentive effect might be that TSOs that are incentivised as intended will respond by offering as little capacity as possible for LTTR auctions. Limiting the transmission capacity allocated for auctions will be an effective hedge for the TSOs financial obligations associated with LTTRs. TSOs might also consider if the relevant zonal prices should be equal, and mitigate congestions by other means than optimal allocation of generation in the day-ahead market. Such 'other means' include counter-trade (which is not as transparent as cross zonal price differences), long-term agreements with selected generators, or even TSO-controlled power plants.

At least for two of the Nordic TSOs, Statnett in Norway and Energinet.dk in Denmark, it is obvious that a requirement to offer LTTRs will not have any incentive effect because their revenue is a function of total costs. For Statnett, the revenue is also a function of performance, however it is more or less predetermined that Statnett is 100 % efficient (benchmarked towards its own performance). A loss in revenue for either of the two TSOs will thus be compensated through increased user tariffs. The user tariffs are set by the TSOs within the decided revenue cap and the prevailing tariff structure given through the regulations. Lost income due to financial trading implies increased end-user tariffs, and vice versa, with no financial impact for the TSOs.

The regulation in Sweden and Finland, Svenska Kraftnät (SVK) and Fingrid respectively, is based on "rate of return" models. The regulators decide a rate of return, and then the principle that the tariffs or prices must give reasonable rate of return is applied. For SVK and Fingrid the regulatory set-up allows only "non-controllable costs" as "pass-through elements" (i.e. costs that will be compensated). Whether or not LTTRs impose incentives for the TSOs depends on the definition of non-controllable costs in each of the countries. Thus, defining costs associated with LTTRs as non-controllable when offering LTTRs with full financial firmness might give these TSOs perverse incentives as described above, because it would be in the TSOs interest to offer as little capacity as possible.

A brief look at the regulatory framework in other European countries[18] indicates that the TSOs in Europe are either regulated through a "cost plus" approach with basically no incentives for cost reductions, a "revenue cap" approach, or a "rate of return" approach. Whether the TSOs have incentives for cost reductions (i.e. possibility to earn extra profits) varies with the regulatory set-up. Some TSOs have specific efficiency targets and some have specific pass-through elements in their regulation. The regulatory details of each country decide whether costs related to LTTRs and curtailment are compensated for. TSOs are basically either in the same situation as Statnett and Energinet.dk, with no economic incentives, or in the same situation as SVK and Fingrid, where incentives depend on the details. There might also be important cultural differences between TSOs and regulatory schemes.

Finally, it should be emphasized that TSOs have more incentives than those introduced through institutionalised economic regulation. Thus even if a TSO has strong economic incentives to offer as much capacity as possible for auctions, or to avoid curtailment when LTTRs approach delivery, it is far from obvious that TSOs actually would jeopardize security of supply in order to increase profits. The responsibility of securing system stability and supply of energy is a strong social and political commitment, and presumably task number one for well-organised TSOs. People trust the TSOs and it is not very likely that TSOs would risk their reputation for a small financial gain.

4.2 Mitigation of poor competition

It is unlikely that LTTRs can play an important role in improving competition in the day-ahead market. The design of the European target model simply does not allow LTTRs to influence the physical flow as determined at the day-ahead stage, see also section 3.1 and 2.3.2. To the extent uncompetitive day-ahead pricing in one or more price zones is the major concern, the suggested requirement on TSOs to offer LTTRs cannot fix the problem. The only time a market participant can exercise market power in the day-ahead market is when a price zone is import congested (all import capacity is fully utilised and local prices are higher than in surrounding areas), see Bushnell and Borenstein (2000) for the theory behind this argument and Mirza and Bergland (2015) for empirical evidence. If an incumbent (or dominant producer) has FTRs for import, there are even stronger incentives for exercising market power.

In the long-term market, i.e. the market for hedging, requiring TSOs to offer LTTRs can clearly improve hedging possibilities for partakers in the physical market, depending on

[18] Information on regulatory set-up is provided in ENTSO-E (2014b).

among other things the precise LTTR design and the existence of other hedging instruments.

However, we note that when or if TSOs offer LTTRs, they are not exposed to the same set of risks that affect traders or other market participants. This implies that they have quite different costs of selling LTTRs. The case of CfDs between Spain and Portugal illustrates this point clearly. In the diagram below, the Spanish supply of CfDs provides the 'floor' of the supply curve. Whereas competing suppliers of such CfDs apparently have costs of offering contracts, the horizontal part of the supply curve (green line) suggests a subsidised supply. Indeed, this horizontal part of the supply is financed by the Spanish congestion rent between Spain and Portugal.[19] In essence, the Spanish operator swaps the volatile cash flow from congestion rent with a fixed LTTR price settled by the intersection of supply and demand. For the TSO, this appears as a riskless game (except for firmness issues). However, the costs are not zero for the society, even though they are socialised via the regulation of the TSO.

[19] The Spanish TSO collects 50 % of the congestion rent (price difference x volume) in the day-ahead market between Spain and Portugal (and the Portuguese collects the other half. The Spanish share matches the TSO's obligations towards the owner(s) of the CfDs the TSO offered in the CfD auction.

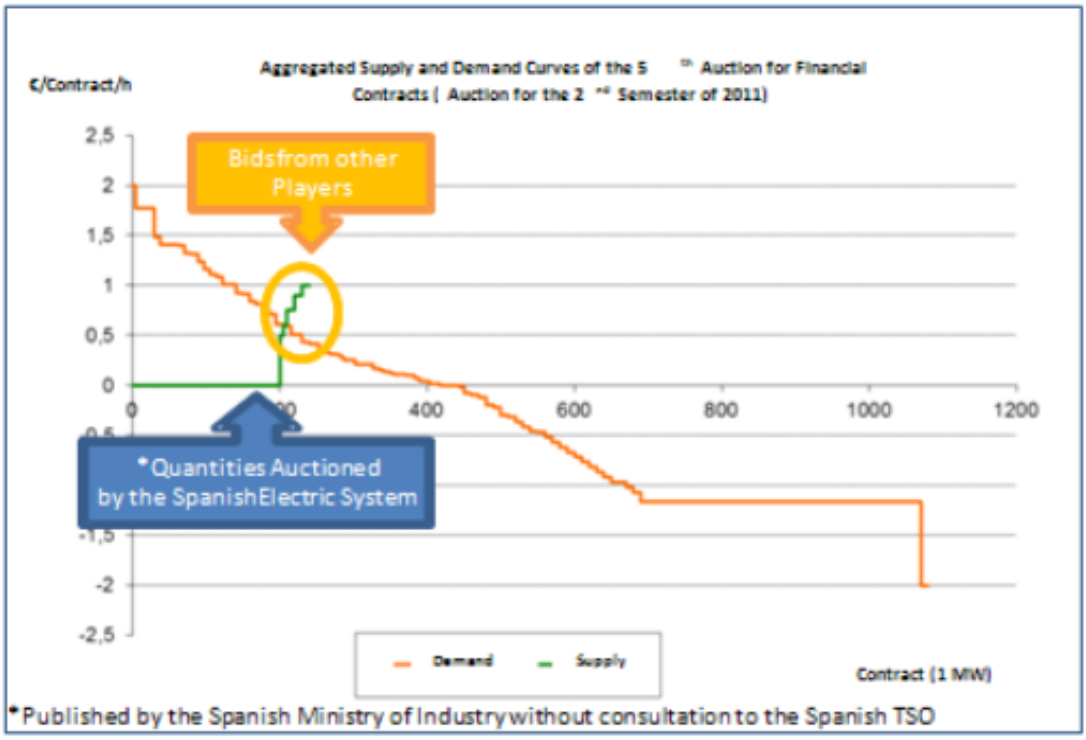

Exhibit 4-1 Supply and demand of CfDs from Spain to Portugal. Source: ENTSO-E (2012)

We also note that LTTRs between a region with fairly liquid hedging instruments in the local area price and a region without well-functioning hedging markets can provide a 'bridge to liquidity'. This does however not fully solve the problem of low liquidity in the domestic market, and might reduce the chances for a true domestic hedging market to evolve. It might even raise the barriers of entry, as the arrangement forces truly domestic market participants, in the low liquidity area, to start trading hedging instruments in adjacent markets in order to gain sufficient hedging at home.

4.3 LTTR design – options or obligations?

Assuming the LTTRs are created to provide efficient hedging to market participants, it really depends on their business models whether the LTTRs should be options or obligations. Only FTR obligations will provide the market participants with a complete hedge that covers price differences in both directions, and that ensure a price level in the importing region that is equal to the hedgeable price level in the exporting region plus the market value of the average price difference between the exporting and importing region. PTRs with UIOSI

and FTR options will cover price differences in one direction, i.e. no negative payouts, and thus provide an incomplete hedge because the value of a PTR or FTR option is uncorrelated with the average (or accumulated) price difference, c.f. the example in chapter 2.2.

It follows that while an option might allow for a higher payout compared to an FTR obligation, this payout will not be directly correlated with the hourly average price obtained in the physical market. This imperfect correlation between the two positions adds a risk dimension to the hedging strategy, because it creates the potential for excess gains or losses (commonly referred to as "basis risk").

Consequently, for an LTTR to be an efficient hedging instrument for business models relying on the *price level* it must be an obligation. Market participants with 'normal' business models in the electricity sector, i.e. power generation, power consumption or supply to end-users, are thus likely to prefer FTR obligations. This is also in line with the observations reported in Hagman and Bjørndalen (2011).

Unfortunately, this is probably the least attractive design for the TSOs who are supposed to offer the LTTRs. This is partly because the basis risk associated with FTR options is a cost factor for the TSO and/or its customers. Another reason is the counterparty risk: if a counterpart fails to reimburse the TSO for the negative price differences, the net cost for the TSO can be substantial. On the other hand, if a clearinghouse is available, this could remove the counterparty risk for the TSO for a moderate cost (but the clearing costs might be significant for some of the LTTRs buyers, and thus not necessarily reduce hedging costs). The fact that most LTTRs currently offered via CASC.EU and CAO (see section 4.5.1) are PTRs with UIOSI, i.e. an option type contract, also suggests, by empirical observation, that TSOs prefer not to issue FTR obligations.

FTR options could be efficient hedging instruments for market participants with business models where the activity/net revenue is correlated with the positive payouts in one direction only. This brings us to the distinction between European and US electricity market design. Whereas the US has a nodal market design, the European target model is a zonal approach. Moreover, while a US generator typically would use FTR options in order to schedule their power plants optimally, European power generators optimise their power plants towards the zonal price where the power plant is located. This is actually one of the major purposes of the zonal approach – the TSO guarantees market participants that there will be no relevant congestion within this zone, which implies the generators are implicitly endowed with a US type FTR from their connection node to the zone. According to the European target model, further optimisation between zones is a task for the power exchanges. The concepts of market coupling and coupling of regions are designed for this purpose.

With respect to the distinction between physical and financial contracts, we first note that PTRs with UIOSI are financially equivalent to FTR options. We also note that FTRs in general, and options in particular, might attract more interest from purely financial market players, who want to trade in the financial market but do not plan to match the FTR with a position in the physical market. [20]

4.4 Time horizons of LTTRs

It is important to recognize that the bulk of participants in the electricity market operate with a long-term perspective (several years). It could be argued that LTTRs for the nearest year(s) as defined in the draft FCA network code are not relevant for these market participants.

We note that in the Nordic market, the 1-year forward contract is by far the most liquid, which suggests that there might be a demand for cross zonal hedging products over the same time horizon. That the front end of the forward curve is most liquid can possibly be explained by common hedging practices in the electricity sector. To allow for flexibility in the hedging strategy, a common approach is to hedge e.g. 25 % of annual volume 4 years ahead, further 25 % 3 years ahead, etc., thereby creating most attention of course to the nearest year(s). Looking to other commodity markets, this practice is also witnessed in e.g. the market for aviation fuel (Carter *et al.*, 2006). Hedgers buy small quantities far out, then hedge close to all exposure as you approach maturity. Essentially, one needs a liquid market on the front part of the curve to facilitate trading further out.

4.5 Operational costs

4.5.1 The Single Allocation Platform (SAP)

The Single Allocation Platform (SAP) will be responsible for performing the forward capacity allocation, and provide a single point of contact for market participants. The SAP, as stipulated in the recent network code on FCA, shall also support anonymous secondary trading. From a practical perspective, even hedgers would prefer that LTTRs allocated in a 'first auction' could be re-sold, because this would allow for adjustment against changes in a physical position. Issuing TSOs could presumably also prefer to have an opportunity to buy back LTTRs if e.g. grid problems force them to reduce available transmission capacity

[20] Hogan (2013) suggest that point-to-point FTR options might be "(…) *more attractive as a tool for hedging purposes, and it is typically the first suggestion from market participants because of the perception that there is a closer analogy to the presumed option not to schedule under a physical right.*"

for a longer period (e.g. a fire in a rectifier for a HVDC line, which could take more than a year to repair). Buying back could be more attractive, rather than paying compensation according to firmness rules.

At this point, there are still discussions about the SAP configurations and design. Essentially it is an exchange for LTTRs, and as such comparable with Nasdaq, EEX and other power exchanges when it comes to the system requirements, costs, etc. It does also appear reasonable to expect that the SAP will be implemented in a way similar to CASC.EU and/or CAO (Common Auction Office), or possibly by combining the two allocation services. CASC.EU is the central auction office for cross-border transmission capacity for Central Western Europe, the borders of Italy, Northern Switzerland and parts of Scandinavia. CAO is the common auction office for allocating cross border transmission capacity for TSOs of the Central Eastern Europe region. The current transaction fees on these platforms are relatively low. Depending on how the SAP is structured in terms of transaction fees, margin requirements etc., hedging through the SAP might turn out to be cheaper at the margin, compared with hedging through e.g. Nasdaq. It is fairly likely there are economies of scale in the operation of the SAP. For market participants in demand of more than one LTTR, it is most likely also a benefit if all different LTTRs can be traded on the same platform, under the same fee-structure, margin requirements, and other relevant details.

On the other hand, and unlike Nasdaq and other existing exchange platforms for long-term power derivatives, it seems as if the SAP will enjoy a monopoly at least in the primary trading of TSO-issued LTTRs, potentially also in the secondary trading. To the extent competition between exchange platforms is feasible, lack of competition is clearly not a benefit.

4.5.2 Financial regulations

Power exchanges are subject to strict financial regulation and monitoring to secure the integrity of the market. A significant part of the costs associated with hedging products is related to clearing and margin requirements. Still, these functions are important because they reduce the counterparty risk inherent in all market transactions, and promote stability of the market mechanism. Interestingly, transmission rights allocated by TSOs are exempt from the financial regulations set out in MiFID 2 (Directive 2014/65/EU), Article 2(1)(n).

We find this surprising for two reasons:

- The LTTRs described in the draft FCA network codes are indeed financial contracts, including PTRs with UIOSI.

- LTTRs will be subject to secondary trading, but the exemption shall not apply with regard to the operation of a secondary market, including a platform for secondary trading in financial transmission rights.

That financial contracts are exempt from the MiFID financial regulatory framework might be considered peculiar. That LTTRs will be exempt from these regulations on a 'first auction' basis, but not whilst traded in the secondary market border on the spectacular. It is difficult to see how the latter promotes efficiency and harmonization of the market place. Thus, it appears that the regulatory treatment of LTTRs, both in the primary and secondary markets, could have a substantial impact on the demand for and trading volumes of the instruments.

4.5.3 Trading role for TSOs

TSOs offering LTTRs via the SAP will hardly be regarded as *participants or traders* in the LTTR market. However, if TSOs are entitled to participate in secondary trading, which they may have strong incentives to do, the matter is more delicate. Nobody would like to see a TSO as a trading entity in a market for LTTRs when the TSO controls one of the most important factors determining the market value of the contracts: transmission capacity. Strict regulations concerning Chinese walls, market sensitive information, etc. must eventually be defined and enforced. Alternatively, TSOs must be refused the right to participate in secondary trading, or else there will be significant costs in terms of lack of trust and the performance of a secondary market. A secondary market without trust is significantly limiting its role as a hedging arena.

Here it hardly matters whether the LTTRs are PTRs, FTRs or even EPADs – to the extent TSOs should be welcome to participate as traders, they must be properly organised in order to prevent insider trading suspicions and mistrust. Some of the alternative measures to TSOs offering LTTRs do not have this problem. That applies to both funding support from TSOs to market making, and to measures directed towards the price formation in the day-ahead market directly.

4.6 Costs associated with operating two parallel systems

While a unified framework might lead to harmonization of the European energy market, implementing a system that relies solely on PTRs with UIOSI or FTRs might prove costly. Such LTTRs are compatible with the hedging environment in most of Europe, with the Nordic region as an important exception. In the Nordic market, opportunities to hedge cross zonal price risk already exists in the form of EPADs. From a practical perspective, requiring the Nordic TSOs to auction LTTRs will mean that market participants have to perform their hedging activities through two platforms and/or with two not fully compatible contracts

(see below). Generally speaking, a limited number of homogenous products leads to less market fragmentation and promotes competition. The draft FCA network code does recognize that if appropriate cross-border hedging opportunities already exist on both sides of an interconnector, there might not be a need for alternative hedging tools.

LTTRs are generally not very compatible with current Nordic hedging practice, as the underlying system price is without geographical reference. 'Unifying' markets by having the Nordic region switching to a hedging model with a geographical reference point will involve transition costs. If one alternatively decides to keep the Nordic model, and introduce LTTRs for the same region that trade on a different platform, there will generally speaking be a cost for the market participants to operate two parallel systems.

One of the greatest concerns in this regard is the concept of liquidity splitting. In Hagman and Bjørndalen (2011), the interviewed market participants were divided in their view on how the introduction of tradable transmission rights would affect the liquidity of cross zonal hedging products. Some stakeholders believed that an introduction of LTTRs would increase the liquidity in the existing market for EPADs. Buying LTTRs can be a risk-reducing strategy for a trader selling EPADs. Other participants were worried that an introduction would split the existing liquidity in system price contracts and EPADs.

If liquidity splitting does occur, this is cause for concern. There is literature that suggests that reducing volume in already thin markets increases price volatility. For example, in a presentation to the U.S. Commodity Futures Trading Commission in 2011 (the regulatory body for U.S. derivatives trading) Fortenbery argued, based on the empirical work of Bozic and Fortenbery (2012), that volatility issues in U.S. dairy derivatives were driven, at least in part, by low trade volume. More recently, work has emerged that suggests reducing speculative trade volumes in even deep markets increases price volatility. Yi and Fortenbery (2013) investigated the impacts of speculative behaviour on overall price volatility for oil, wheat, and coffee futures and found that in each case less speculative activity led to increases in price volatility. Increased volatility increases both hedging and trading costs, due to increased cash flow needs to maintain margin positions.

We see both the arguments for increased and decreased liquidity in EPADs as plausible. It is ultimately an empirical question whether the net effect will be an increase or a decrease, and the design of the Network Code(s), and in particular the SAP, will have a substantial impact on this effect.

5 Summary and conclusions

The network code on FCA seems to have been drafted on the basis of an hypothesis that increased cross zonal trade will improve situations with poor competition in electricity markets, and that appropriate hedging instruments for cross zonal trade are essential to facilitate such trade.

Apparently, it is further believed that requiring transmission system operators, TSOs, to offer long-term transmission rights, LTTRs, will encourage these entities to increase their efforts to avoid reductions in available transmission capacity between price zones when facing internal congestion and operational challenges, and as such facilitate competition in the electricity market.

Our position is that whether regulatory market intervention is duly justified depends on the nature of the problem, the available measures to mitigate it, and the costs and benefits associated with the different measures (Coase, 1960).

We are not convinced there really is a missing or imperfect market for cross zonal hedging products in the Nordic region and adjacent markets. This is essentially an empirical question that regulators should answer before requiring interventions in the market. Such analysis should also include the role of the end-user market in the relevant zones.

The discussion in section 4.1 reveals that Nordic TSO's are not likely to respond to economic incentives from selling LTTRs. A requirement for TSOs to sell LTTRs will not encourage them to make more effort to avoid reductions in available transmission capacity between price zones when facing internal congestion and operational challenges. This is because their revenue is regulated to be independent of short-term profit or loss from congestion rent and the eventual sale of LTTRs.

Further, we are convinced that problems of insufficient competition in day-ahead markets within zones, if they exist, cannot be mitigated by regulatory interventions in the market for hedging cross zonal price differences. The design of the market coupling and coupling of regions implies that the actual physical day-ahead and intra-day power flow is fully independent from any LTTRs, which are or can be regarded as financial contracts. This is one of the key features of the European target model for the short-term markets. See also Murphy and Smeers, 2012, Munthe et al., 2007, and Le Coq and Orzen, 2006).

Further, it appears that requiring TSOs to swap their volatile congestion rents with fixed sales revenues from sale of LTTRs, in fact constitutes a subsidy of hedging activities that will be paid for by the customers of the TSO via the TSO-tariffs for transmission services.

An interesting finding is that the LTTR design that is potentially most attractive for the market participants, FTR obligations, is the least attractive design for the TSOs.

With particular interest in the Nordic market, we note that hedging based on LTTRs defined as PTRs with UIOSI and FTR options and obligations is a fundamentally different approach than hedging based on derivatives of the non-geographical Nordic system price in combination with EPADs to cover the difference between the system price and the various price zones.

Returning to the problem of imperfect competition and hedging opportunities the FCA network code is supposed to fix, insufficient competition in short-term markets and closely related to this, missing markets for cross zonal hedging instruments, the requirement for TSOs to offer LTTRs fails to address the problem(s) properly:

- Insufficient competition in day-ahead markets is best addressed by measures like increasing the physical network capacity and regulating the behaviour of dominant market participants. Improving the hedging opportunities does not address the root of the problem.
- Insufficient hedging opportunities can indeed be mitigated by obligations of TSOs to offer LTTRs. However, the TSOs are likely to offer a design that fits their situation best, which unfortunately is the least attractive design for normal market participants looking for hedging instruments.
- For the Nordic market, the current hedging practices are not directly compatible with the suggested LTTR designs. Thus, there is a risk of significant loss of liquidity and increased hedging costs in this region (see also Li and Fortenbery (2012) for a discussion about the relationship between speculation in futures markets and volatility in cash markets).

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Appendix: Project specification

There is an ongoing process in the EU related to the development of "Network Code on Forward Capacity Allocation" (NC FCA). The aim of the NC FCA is to establish common rules for Forward Capacity Allocation and providing market participants with sufficient hedging opportunities related to the area price risk. The European Network of Transmission System Operators for Electricity (ENTSO-E), the Agency for energy regulators in Europe (ACER), the European Commission (EC), as well as the National Regulatory Authorities, are involved in the process.

When developing Framework Guideline on Capacity Allocation and Congestion Management for Electricity (FG CACM), the regulators issued an Initial Impact Assessment (IIA) (2010). The overarching objective of achieving an efficient forward market was described as follows: "*There is a need for cross-border risk hedging mechanisms in order to have an internal and seamless European energy market across all timeframes. One key role of the forward market is to provide market participants with the ability to manage risk associated with cross-border trading.*"

In ACER`s Framework Guidelines on CACM (2011) it is stated that the Network Code "*shall foresee that the options for enabling risk hedging for cross border trading are Financial Transmission Rights (FTR) or Physical Transmission Rights (PTR) with Use-It-Or-Sell-It (UIOSI), unless appropriate cross-border financial hedging is offered in liquid financial markets on both side of an interconnector.*"

The option of using forward financial electricity markets for hedging purposes is also described in Reg. (EC) No 714/2009[21] where it is stated:

"In regions where forward financial electricity markets are well developed and have shown their efficiency, all interconnection capacity may be allocated through implicit auctioning."

The FCA NC makes clear that the reference tools to allow for cross-border hedging are FTR or PTR with UIOSI issued by the TSOs. However, an exemption is possible if cross-border financial hedging tools on both side of an interconnector exist and have shown their efficiency. In such a case, issuing of Long-Term Transmission Rights (LTTR) is not obligatory. A formal decision from the relevant regulators will be required for this derogation. The NRAs decision shall be based on an assessment, which shall include at least a consultation with

[21] Regulation (EC) No 714/2009 on conditions for access to the network for cross-border exchanges in electricity

Market Participants and "*an evaluation on whether Forward financial electricity markets are well developed and have shown their efficiency or whether other cross zonal hedging opportunities are needed*". ACER has proposed specific, quantitative criteria for such an assessment.

Further, the Network Code paves the way for the establishment of a Single Allocation Platform who will be responsible for the operation of Auction procedures related to LTTRs. This is not in line with the current system for hedging in the Nordic electricity markets, where financial platforms are used. The current hedging products in the Nordic electricity market are contracts available in the financial market. It is possible to buy contracts to hedge the risk associated with the volatility in the spot price, and other contracts (e.g. EPADs) to hedge the area price risk. These contracts are based on commercial terms and are available bilaterally or over a commercial trading platform. Products related to the Nordic system price are typically high in traded volume and liquidity.

The introduction of LTTRs in the Nordic electricity market can potentially have several consequences on the current market design and efficiency. The aim of this study is to get a theoretical economical evaluation of these potential effects, and to clarify on what grounds regulatory intervention could be justified given that there already exists a market for price hedging.

Scope of study

The consultant should consider the following in the course of the study:

1. To give a description of the current market design in the Nordic electricity market with focus on fundamental market players` possibilities for price hedging. This includes both the physical and financial electricity market. The contract types in the end-user market should also be described.

2. To describe the current incentives of the Nordic TSOs to allocate transfer capacity to the market to facilitate cross-border trade in electricity.

3. To make an economic theoretical assessment of potential justifications for regulatory interventions in forward electricity markets. (E.g. market failures etc.)

    - What could justify imposing a requirement on the TSOs to offer LTTRs in the Nordic forward electricity market?
    - The study shall give examples from other relevant markets where regulatory intervention has been justified and describe alternative measures than LTTRs that could serve the purpose of providing better hedging opportunities for market players.

4. To make an economical assessment on whether the introduction of LTTRs between bidding zones could provide the market participants with better hedge than what can be provided in the Nordic forward financial electricity market. Look specifically at:
    - The efficiency of the hedge for a producer and a consumer, whilst taking firmness provisions into account.
5. To make an assessment on the associated costs for implementing a system for allocation of LTTRs in addition to the financial forward market in the Nordic region. Look specifically at:
    - The cost of having two parallel systems (Allocation platform for LTTRs and the financial forward market). Transaction costs for market participants and TSOs, including the impact on network tariffs, should be assessed.
    - Possible effects on the already existing financial market in terms of liquidity splitting.

The successful vendor will present a well thought through methodology and work plan. Furthermore, NVE will emphasise international academic expertise and qualifications of the personnel. We encourage the suppliers to seek partners outside the Nordic region with experience within this field. NVEs seeks academic with a good standing within his or her field, documented by publications and previous relevant projects.

The final report should be submitted in English.

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