FTRs in the Nordic electricity market

Pros and cons compared to the present system with CfDs

Elforsk rapport 11:16

Björn Hagman, Jørgen Bjørndalen

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ELFORSK

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Preface

The Market Design research programme has been operating for more than 10 years. Over the time the focus has shifted from the national to the Nordic and, in certain cases, to the European level. This emphasis will continue over the next three years, with the European perspective dominating.

In this report written by Björn Hagman and Jörgen Björndalen a new financial instrument that may be introduced in the Nordic market as a direct consequence of European harmonisation is studied.

At present, market participants in the Nordic financial market purchase Contracts for Difference to hedge against the basis risk when area prices are not equal to the System Price. CfDs are issued by the market players without the TSO's involvement. This is different from the European target model in which TSOs issues Financial or Physical Transmission Rights. The purpose of this study is to analyze how the introduction of Financial Transmission Rights would impact market actors and TSOs and list pros and cons compared to the present system with CfDs.

More information about the Market design Research program, finished reports and conference documentation can be found at www.marketdesign.se.

Stockholm, April 2011

Peter Fritz
Secretary of the Market Design-program
Elforsk AB

Sammanfattning

Denna rapport analyserar hur en introduktion av finansiella transmissionsrätter (FTR) på den nordiska elmarknaden skulle påverka marknadsaktörer och stamnätsföretag. Fördelar och nackdelar jämfört med det nuvarande systemet med s k CfD-kontrakt listas.

Bakgrunden för studien är det pågående Europeiska arbetet beträffande ”framework guidelines” och ”network codes”. Stamnätsföretag ska enligt målmodellen för terminsmarknaden sälja FTR eller fysiska transmissionsrätter (PTR). Efter allmän konsultation redovisade ERGEG februari 2011 ett slutligt utkast till riktlinjer för kapacitetsallokering och hantering av överföringsbegränsningar (FG on CACM). Det föreskrivs i punkten 4.2 att stamnätsföretagen ska bjuda ut FTR och PTR såvida det inte finns lämpliga finansiella säkrings-instrument för gränsöverskridande handel på likvida finansiella marknader.

Konsultationssvaren till ERGEG visar att fokus i Europa beträffande FTR är FTR optioner med timvis avräkning. Vi förväntar oss därför att ett framtida krav på europeiska stamnätsföretag att i auktioner bjuda ut FTR kommer att innefatta FTR-optioner men inte FTR-obligationer, åtminstone inte under de första faserna. Alternativet FTR-obligationer innebär att köparen erhåller eller ska betala den genomsnittliga prisskillnaden mellan två områden under den i kontraktet specificerade tidsperioden (t ex år, kvartal eller månad). FTR-optioner med timvis avräkning betyder å andra sidan att för varje timme med flaskhals i den i kontraktet specificerade riktningen ska köparen erhålla prisskillnaden mellan de två områdena.

Vi har intervjuat 9 marknadsaktörer och 7 andra intressenter i Sverige, Norge och Finland.

E.ON och Vattenfall framhåller att FTR skulle ge dem en bättre säkring när produktion i ett område säljs till en kund i ett annat område. De andra intervjuade marknadsaktörerna kunde inte se att FTR i sig skulle förbättra deras riskhantering. Det gemensamma skälet för denna uppfattning är att de flesta marknadsaktörerna i den nordiska regionen använder kontrakt med det nordiska systempriset som referens för att säkra den huvudsakliga prisrisken medan områdesprisrisker säkras med s k CfD-kontrakt (kontrakt beträffande skillnaden mellan ett områdespris och det nordiska systempriset).

Vi finner det svårt att tro att FTR skulle kunna bli populära säkringsinstrument i Norden. När den huvudsakliga prisrisken säkras med systemprisderivat kommer FTR endast att ersätta en områdesprisrisk med en annan. Bara ett fåtal vertikalt integrerade företag använder en affärsmodell där produktionen är en säkring för försäljningen till kunder (eller vice versa) och där FTR kan vara ett attraktivt säkringsinstrument.

Alla intervjuade marknadsaktörer önskar en ökad likviditet i CfD-kontrakt. Några aktörer tror att en introduktion av FTR skulle kunna öka likviditeten i CfD-kontrakt. Att köpa FTR kan vara en riskreducerande strategi för en trader som säljer CfD. Några andra aktörer var oroade för att fokus på FTR kan öka fokus på bilaterala områdespriskontrakt och således resultera i reducerad likviditet i börsnoterade systempriskontrakt. Vi ser både argumenten för ökad likviditet och för minskad likviditet i CfD-kontrakt som rimliga. Det är till sist en empirisk fråga om nettoeffekten kommer att bli en ökning eller en minskning.

Flera av aktörerna med trading som en kärnverksamhet var intresserade i FTR som en ny tradingprodukt. Särskilt företag med europeisk fokus var mycket intresserade. Inget av företagen med huvudsaklig säkringsfokus för sin trading trodde att handel i FTR skulle bli en viktig del av deras handelsaktiviteter.

Vi tror att FTR kommer att bli intressant för marknadsaktörer med tradingfokus, särskilt om FTR kommer att noteras på börs och bli möjliga att cleara med ett clearinghus. Vi tror inte att FTR kommer att bli en viktig del av handelsstrategierna för företag med säkringsfokus för sin trading. Oelastiskt auktionsutbud av FTR från stamnäts-företagen och potentiellt få aktörer i auktionerna kan ge en ganska hög riskpremie till marknadsaktörer som deltar i FTR-auktionerna. Denna riskpremie måste till sist betalas av nätanvändarna via nättarifferna.

Nästan alla intervjuade trodde att FTR skulle ändra åtminstone stamnätsföretagens kortsiktiga beteende när det gäller underhålls-planering och störningshantering. De förväntar att stamnätsföretagen vidtar åtgärder för att minimera omfattningen av minskningar i överföringskapacitet och att de flyttar planerat underhåll till perioder med mindre risk för allvarliga marknadskonsekvenser. Det finns mer motsatta uppfattningar bland de intervjuade beträffande konsekvenserna för investeringar i ökad överföringskapacitet. Några tror att FTR kommer att öka incitamenten att investera. Andra är oroade att incitamenten att investera kan bli minskade, särskilt om kravet på stamnätsföretagen är att de ska auktionera ut en viss andel av den totala överföringskapaciteten som FTR.

Vår uppfattning är att ändringar i stamnätsföretagens beteende till följd av krav att sälja FTR kommer att bero på om stamnätsföretagen har en kostnadsbaserad intäktsreglering eller en incitamentsbaserad reglering eller en kombination. Ändringarna kommer också att bero på hur de olika måttstockarna i en incitamentsbaserad reglering är utformade. Ett krav att utfärda FTR kan ha en positiv påverkan på kortsiktig och långsiktig tillgänglighet men det kan också medföra kontraproduktiva incitament och beteenden. Följaktligen bör ett krav att utfärda FTR åtföljas av en översyn av den sammantagna

regleringen av stamnätsföretaget för att undvika kontraproduktiva incitament och beteenden. Det är viktigt att ökad fokus på kortsiktig företagsekonomi inte kommer på bekostnad av de långsiktiga skyldigheter som stamnätsföretagen nu har beträffande samhällsekonomisk utbyggnad och underhåll av överföringsnäten.

Några alternativ till FTR syftande till förbättrad riskhantering på den nordiska marknaden eller ökade tillgängliga överföringskapaciteter nämndes i intervjuerna och på workshopen. Ett alternativ är ett frivilligt åtagande av stamnätsföretagen att bjuda ut CfDs via auktioner. Svenska Kraftnät kan exempelvis som ett första steg bidra till likviditeten i de fyra nya svenska elområdena genom att sälja CfDs i de två södra underskottsområdena och köpa CfDs i de två norra överskottsområdena. Ett annat alternativ är att stamnätsföretagen på något sätt ska stödja en market maker-funktion på CfD-marknaden. Ett tredje alternativ är ett krav på minimikapaciteter mellan spotmarknadens olika områden. Stamnätsföretagen måste i så fall genomföra mothandel om minsta tillåtna kapacitet är högre än verklig tillgänglig kapacitet.

Vi tror att ett frivilligt åtagande av stamnätsföretagen att auktionera ut CfDs eller att stödja en market maker-funktion kan ytterligare förbättra möjligheterna att säkra områdesprisrisker. Det tredje alternativet har nämnts flera gånger under senare år och har så långt erhållit otillräckligt stöd för att bli accepterat. En bättre väg för att maximera tillgänglig överföringskapacitet för marknaden är troligen att inkludera kapacitetsallokeringen och –tillgängligheten som kvalitets-parametrar i intäktsregleringen av stamnätsföretagen.

Summary

This report analyses how an introduction of financial transmission rights (FTRs) in the Nordic electricity market would impact market actors and TSOs. Pros and cons compared to the present system with contracts for differences (CfDs) are listed.

The background for the study is the ongoing European work regarding framework guidelines and network codes. TSOs shall according to the target model for the forward market sell FTRs or physical transmission rights (PTRs). ERGEG reported February 2011 after public consultation a final draft framework guideline on capacity allocation and congestion management (FG on CACM). It is stipulated in the provision 4.2 that TSOs shall provide FTRs or PTRs unless appropriate cross-border financial hedging instruments are offered in liquid financial markets.

The consultation responses to ERGEG show that the European focus regarding FTRs is FTR options with hourly settlement. We therefore expect that a future requirement on European TSOs to auction FTRs will include FTR options but not FTR obligations, at least not in the first stages. The alternative FTR obligations mean that the buyer receives or pays the average price difference between two areas during a specified calendar period (e.g. year, quarter or month). FTR options with hourly settlement mean on the other hand that the buyer will receive the price difference between the two areas for every hour with congestion in the specified direction.

We have interviewed 9 market players and 7 other stakeholders in Sweden, Norway and Finland.

E.ON and Vattenfall stated that FTRs would give a better hedge if production in one area is sold to a customer in another area. Other interviewed market players could not see that FTRs in itself would improve their risk management. The common reason for this view is that most market players in the Nordic region hedge the basic price risks by means of contracts with reference to the Nordic system price and hedge the area price risk with CfD-contracts (contracts regarding the difference between an area price and the system price).

We find it hard to believe that FTRs will be popular hedging instruments in the Nordic region. When the basic hedge is done in system price derivatives, FTRs will only replace one area price uncertainty by another. Only a few vertically integrated companies employ a business model where generation is the hedge for retail sales (or vice versa) and where FTRs can be an attractive hedging instrument.

All interviewed market players wanted an increased liquidity in CfD-contracts. Some players believed that an introduction of FTRs would increase the liquidity in CfDs. Buying FTRs can be a risk-reducing strategy for a trader selling CfDs. Some other players were worried

that an introduction would split the existing liquidity in CfDs. Another worry from some players was that a focus on FTRs could increase the focus on bilateral area price contracts and thus result in reduced liquidity in exchange-listed system price contracts. We see both the arguments for increased and for decreased liquidity in CfDs as plausible. It is ultimately an empirical question whether the net effect will be an increase or a decrease.

Several of the market players with trading as a core activity were interested in FTRs as a new trading product. Especially companies with a more European trading focus were very interested. None of the companies with primary hedging focus for their trading believed that FTR trading would be an important part of their trading activities.

We believe that FTRs will be interesting for market players with a trading focus, especially if the FTRs are listed at an exchange and possible to clear with a clearinghouse. We do not believe that FTRs will be an important part of trading strategies for companies with a hedging focus for their trading activities. Inelastic auction supply of FTRs from the TSOs and potentially few market players in the auctions can give quite high-risk premium to market players participating in the FTR auctions. In the end, this risk premium has to paid by the network users via network tariffs

Nearly all interviewees believed that FTRs would change at least the short-term behaviour of TSOs regarding maintenance planning and breakdown management. They expect TSOs to perform measures in order to minimise the extent of transmission capacity reductions and to move planned maintenance to periods with less risk for severe consequences for the market. There are more opposite views among the interviewees regarding the consequences for investments in increased transmission capacity. Some believe that FTRs will increase the incentives for TSOs to invest. Others are worried that the incentives to invest can be reduced, especially if the requirement on TSOs is that they shall auction a certain percentage of the total transmission capacity as FTRs.

Our opinion is that changes in TSO behaviour because of requirements to sell FTRs will depend on whether TSOs have a cost plus regulation or an incentive regulation or a combination. The changes will also depend on how performance measures in an incentive regulation are designed. A requirement to issue FTRs may have a positive impact on short-term and long-term availability, but may also introduce counterproductive incentives and behaviour. Hence, a requirement to issue FTRs should be followed by an overview of the combined TSO regulation to avoid counterproductive incentives and behaviour. It is important that an increased focus on short-term business economics will not be at the expense of the long term obligations TSOs now have

with respect to socio-economic development and maintenance of the transmission network.

Some alternatives to FTRs aiming at improved risk management in the Nordic market and increased available transmission capacities were mentioned in the interviews and at the workshop. One alternative is a voluntary commitment by TSOs to offer CfDs via auctions. Svenska Kraftnät can e.g. as a first step contribute to liquidity in the four new Swedish bid areas by selling CfDs in the two southern deficit areas and buying CfDs in the two northern surplus areas. Another alternative is that TSOs should support some kind of a market maker service in the CfD market. A third alternative is a requirement on minimum capacities between zones in the day-ahead market. The TSOs will in this alternative have to perform countertrade if a required minimum capacity is higher than the real available capacity.

We believe that a voluntary commitment by TSOs to auction CfDs or to support a market maker service can further improve the opportunities to hedge area price risks. The third alternative has been mentioned several times during the last years, and has so far received insufficient support to be accepted. A better way to maximise available transmission capacity for the market is probably to include capacity allocation and availability as quality parameters in the revenue regulation of TSOs.

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1 Background and purpose of the study

The Market Design Programme within Elforsk has asked for a study of FTRs in the Nordic electricity market. The study shall describe how FTRs can work in the Nordic market. The study shall analyze how the introduction of FTRs would impact market actors and TSOs and list pros and cons compared to the present system with CfDs.

The background for the request is the ongoing European work regarding framework guidelines and network codes. The Project Coordination Group (PCG), chaired by the European Energy Regulators, agreed one year ago upon target models for i.a. forward markets. TSOs shall according to the target model sell financial transmission rights (FTRs) or physical transmission rights (PTRs).

The study has been performed as a joint project by Björn Hagman, Hagman Energy AB and Jørgen Bjørndalen, ECgroup AS.

The Market Design Programme appointed an advisory reference group for the study. The reference group consisted of the following members:

Petri Eväsoja, Fortum

Håkan Feuk, E.ON

Peter Fritz, Market Design

Tobias Johansson, Vattenfall

Bo Lindörn, Oberoende Elhandlare

Jens Nordberg, DinEl

Tania Pinzón, Svenska Kraftnät

Marie Pålsson, Energimarknadsinspektionen

Magnus Thorstensson, Svensk Energi

The Market Design Programme organized a workshop on 4 February 2011. The purpose of the workshop was to discuss the consequences of a possible introduction of FTRs in the Nordic market and to discuss the conclusions in a draft report from the project. The workshop was attended by the reference group and 16 invited representatives for stakeholders in the Nordic market. Valuable advice and comments were given in the discussions in the workshop. However, the analysis and the conclusions presented in this report is the responsibility of the authors.

2 EU rules and ongoing work regarding long-term capacity allocation

2.1 Regulation (EC) 1228/2003 and Regulation (EC) 714/2009

Regulation (EC) 1228/2003 on conditions for access to the network for cross-border exchanges in electricity was decided 2003 and includes rules for cross-border trade and capacity allocation.

The annex to the regulation was amended 9 November 2006. The new annex (Congestion Management Guidelines) includes many rules and guidelines regarding congestion management.

Regulation 1228/2003 was on 3 March 2011 repealed by a new regulation, Regulation (EC) 714/2009. The new regulation was decided in 2009 and was a part of the 3rd package for the internal market for energy. It includes the rules in the first regulation and congestion management guidelines are attached as Annex 1. The new regulation includes also the establishment of the ENTSO for Electricity (ENTSO-E) and the establishment of network codes.

Article 16 (1) in the new regulation says as a general principle that *"network congestion management methods shall be addressed with non-discriminatory market-based solutions, which give efficient economic signals to the market participants and transmission system operators involved"*.

Article 16 (3) stipulates that *"the maximum capacity of the interconnections and/or the transmission networks affecting cross-border flows shall be made available to market participants, complying with safety standards of secure network operation".*

Any revenues from the allocation of interconnection capacity shall according to article 16 (6) be used for *"guaranteeing the actual availability of the allocated capacity and/or maintaining and increasing interconnection capacities".* Subject to regulatory approval, revenues that cannot be efficiently used for these purposes may up to a maximum amount be used as income to be taken into account by the regulatory authorities. The rest of revenues shall be placed on a separate internal account until it can be spent on the first two purposes.

Point 2.1 in Congestion Management Guidelines says that *"congestion-management methods shall be market-based in order to facilitate*

efficient cross-border trade. For that purpose, capacity shall be allocated only by means of explicit (capacity) or implicit (capacity and energy) auctions. Both methods may coexist on the same interconnection. For intra-day trade continuous trading may be used".

Point 2.2 says that *"depending on competition conditions, the congestion-management mechanisms may need to allow for both long and short-term transmission capacity allocation"*.

The access rights for long and medium-term allocations shall according to point 2.5 *"be firm transmission capacity rights. They shall be subject to the use-it-or-lose-it or use-it-or-sell-it principles at the time of nomination."*

Point 2.8 allows that all interconnection capacity is allocated through implicit auctioning *"in regions where forward financial electricity markets are well developed and have shown their efficiency".*

In point 2.12 it is stipulated that *"capacity shall be freely tradable on a secondary basis, provided that the TSO is informed sufficiently in advance".*

If a TSO does not fulfil its obligation, it shall according to point 2.13 be *"liable to compensate the market participant for the loss of capacity rights. No consequential losses shall be taken into account for that purpose."*

2.2 Establishment of network codes

The process for establishing network codes is described in Article 6 of the new regulation. The process involves the Commission, the new agency ACER (Agency for the Cooperation of Energy Regulators), ENTSO-E and other relevant stakeholders.

"1. The Commission shall, after consulting the Agency, the ENTSO for Electricity and other relevant stakeholders, establish an annual priority list identifying the areas set out in article 8(6) to be included in the development of network codes.

2. The Commission shall request the Agency to submit to it within a reasonable period of time not exceeding six months a non-binding framework guideline (framework guideline) setting out clear and objective principles, in accordance with article 8(7), for the development of network codes relating to the areas identified in the priority list. Each framework guideline shall contribute to non-discrimination, effective competition and the effective functioning of the market. Upon a reasoned request from the Agency, the Commission may extend that period.

3. The Agency shall formally consult the ENTSO for Electricity and the other relevant stakeholders in regard to the framework guideline,

during a period no less than two months, in an open and transparent manner.

4. If the Commission does not consider that the framework guideline does not contribute to non-discrimination, effective competition and the efficient functioning of the market, it may request the Agency to review the framework guideline within a reasonable period of time and re-submit it to the Commission.

5. If the Agency fails to submit or re-submit a framework guideline within the period set by the Commission under paragraphs 2 or 4, the Commission shall elaborate the framework guideline in question.

6. The Commission shall request the ENTSO for Electricity to submit a network code which is in line with the relevant framework guideline, to the Agency within a reasonable period of time not exceeding 12 months.

7. Within a period of three months of the day of the receipt of a network code, during which the Agency may formally consult the relevant stakeholders, the Agency shall provide a reasoned opinion to the ENTSO for Electricity on the network code.

8. The ENTSO for Electricity may amend the network code in the light of the opinion of the Agency and re-submit it to the Agency.

9. When the Agency is satisfied that the network code is in line with the relevant framework guideline, the Agency shall submit the network code to the Commission and may recommend that it is adopted within a reasonable time period. The Commission shall provide reasons in the event that it does not adopt that network code."

The network codes shall cover 12 areas that are listed in Article 8 (6). One of the areas is called *"capacity-allocation and congestion-management rules".*

The European energy regulators expected in their 2011 Work Programme that the priority list from the Commission for 2011 would include a framework guideline on capacity allocation and congestion management. ACER became operational from 3 March 2011 when the 3rd Package entered into force.

Several steps have been taken during the last years in order to prepare such a framework guideline.

2.3 Target Model from the Project Coordination Group (PCG)

At the Florence Forum in November 2008, ERGEG was invited to establish a Project Coordination Group of experts with participants from the Commission, Regulators, ETSO, Europex, Eurelectric and

EFET. The task was to develop a practical and achievable model to harmonise interregional and then EU-wide coordinated congestion management and to propose a roadmap with concrete measures and a detailed timeframe.

PCG was chaired by the European Energy Regulators and had eight meetings. A target model and a roadmap for capacity allocation and congestion management were proposed at the Florence Forum in December 2009. The target model covered forward, day-ahead, intraday and balancing markets as well as capacity calculation and governance issues.

The proposed target model for day-ahead markets was to implement a single price coupling all over Europe with one single matching algorithm.

The proposed target model for intraday markets was continuous trading based on a shared order book function. Bids in one local order book should be available in another local order book subject to the availability of cross-border capacity. Full harmonisation of balancing markets was not seen as a prerequisite for cross-border balancing. The proposal was therefore a more pragmatic approach focusing on manually activated reserves, harmonisation of gate closure times and technical characteristics.

The proposed target model for forward markets was that TSOs should issue transmission rights on a forward basis. The amount of capacity should be maximised across all timeframes. These transmission rights were to be issued on a regional basis with a high level of compatibility. They could either be between bidding areas or between a reference system area and a bidding area. In case of physical rights, they should be granted as options with use-it-or-sell-it (UIOSI). In case of financial rights they could be either options or obligations.

Establishing a secondary market for trading transmission rights was seen as a very high priority. The transmission rights should be able to be split and resold without constraints – down to individual hours and in 1 MW units. Financial firmness of transmission rights was seen as an essential feature to make secondary markets work properly. The target model options should be implemented across Europe as soon as possible and by 2015 at latest.

PCG proposed that available forecasted transmission capacity should be sold in line with what is traded in energy markets and mentioned as indicative percentages 10 % of forecasted transmission capacity for Y+3 (the third next year), 20 % for Y+2 and 40 % for Y+1.

The Florence Forum in December 2009 thanked PCG for the good work and welcomed the establishment of a European target model for the electricity market and a tentative roadmap for the implementation. The

forum emphasised the need to continue the work in form of concrete implementation projects.

2.4 Draft Framework Guidelines (FG on CACM)

At the Florence Forum in December 2009, it was agreed that ERGEG would continue the work by PCG through the preparation of a draft framework guideline on capacity allocation and congestion management. The work started with an impact assessment. An Ad Hoc Advisory Group (AHAG) was established with the task to assist ERGEG in overseeing the work and solving issues, which might hinder progress.

ERGEG was invited in a letter from the Commission on 26 March 2010 to develop framework guidelines on capacity allocation and congestion management (FG on CACM).

On 8 September 2010 ERGEG sent a draft FG on CACM on public consultation together with an Initial Impact Assessment (IIA). Any comments should be received by 10 November 2010.

Following the consultation with stakeholders, ERGEG reported February 2011 a final draft FG on CACM.

The FG on CACM is structured according to four objectives. Objective 3 is "To achieve efficient forward market". The following text is presented in this part of FG on CACM:

"Objective #3: To Achieve Efficient Forward Market

Capacity allocation methods for the forward market

4.1 The objective of long-term transmission rights, physical or financial, is to provide to market participants long-term hedging solutions against congestion costs and the dayahead congestion pricing, compatible with zone delimitation.

4.2 It is within that framework that the CACM code(s) 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.

4.3 The nature of PTR and FTR in terms of options or obligations should be defined in the respective CACM code(s). The CACM code(s) shall foresee a harmonised set of rules for borders where PTRs with UIOSI are applied and a harmonised set of rules for borders where FTRs are applied.

4.4 The CACM code(s) shall provide for a single platform (single point of contact) for the allocation and nomination (in case of PTRs) of long-term transmission rights (PTR and FTR).

4.5 PTR shall be options and subject to UIOSI. FTRs may allow for both possibilities (options or obligations). Hybrid solutions, mixing both options on the same border, shall not be implemented.

Time frames, volumes and secondary market with relevance for PTR and FTR

4.6 PTR shall be subject to UIOSI at the time of nomination (or equivalent market allocation process), which means as a default the resale of non-nominated rights. TSOs shall give the total financial resale value of capacity (in the case of an explicit auction this is equal to the clearing price of the auction in which the capacity is resold, in the case of an implicit auction this is equal to the day-ahead price differential between the two zones) back to the market players who are the PTR capacity owners.

4.7 Volume of long-term capacity rights shall be determined by TSOs in accordance with the technical capabilities of the network and for each long-term time frame. The CACM code(s) shall ensure that the TSOs submit (at least indicative) levels of capacity available for the whole year sufficiently in advance before the yearly allocation takes place. NRAs shall review and approve the volume of yearly capacity rights, as well as the principles for sharing capacity between the different time frames.

4.8 In line with the Article 2(12) of the CM Guidelines, the CACM code(s) shall foresee that the TSOs provide a single platform for anonymous secondary trading."

The primary problem to be addressed with FG on CACM is according to the IIA *"the presently inefficient and sub-optimal use of transmission network capacity between and within the control areas in the EU"* (p. 9).

In p.10 it is stated: *"The CACM methods applied at many interconnections have not enabled market liquidity and formation of reliable prices neither in day-ahead nor - consequently - in forward electricity markets."*

The IIA mentions the following specific objectives regarding the forward market (p. 15):

"Objective #3: To achieve efficient forward market

The rules and regulations of the future CACM framework should also ensure reliable, fair and competitive price signals and liquidity of the forward electricity market.

One important prerequisite for this is the liquidity and proper functioning of the day-ahead market in the EU. Moreover, access of market participants and actors to all relevant information necessary for efficient price formation and trade on a regional and European basis and for effective functioning of the market shall be ensured for the forward market as well.

Within this context it is further important that the future CACM rules for the forward electricity market take into account both the financial and physical products as applicable and foresee the methods for "reuse" and optimisation of those capacity which might be not needed by the market participants who have initially obtained them (e.g. adhering to the Use-It-Or-Sell-It principle).

The existing national market rules for the forward markets that require harmonisation shall be identified and adequate harmonisation methods and implementation developed at the regional and EU level. The implementation of the CACM solutions for the forward market should also ensure future compatibility with the EU Target Model.

Coordination among the TSOs, PXs and other actors in charge of implementing the future CACM rules for the forward electricity markets remains an essential and key point."

The IIA presents the following conclusions and preferred policy options for the forward market (p. 55-56):

"There are two basic options to enable risk hedging for cross-border trading, FTR, PTR and, in the case where there are liquid and well developed financial markets, a third option through financial instruments such as Contracts for Differences.

As the original capacity owner and beneficiary as regards congestion rents, long-term capacity products shall be provided by TSOs to market participants. Due to the same economic outcome, PTR combined with a UIOSI mechanism shall be implemented in the short term starting with a regional implementation approach, whereas introduction of FTRs shall be prepared for the medium term.

At the same time, the possibility to implement FTRs immediately between some regions/countries/zones might be given, provided that the necessary coordination with (existing) PTR with UIOSI mechanism between other regions/countries/zones is ensured in order not to hinder progress in the market integration process.

PTRs with UIOSI and then FTRs (later on) shall equal the total volume of physical transmission capacity as the linkage between quantities of financial hedging products and physical capacity ensures TSOs' ability to pay redispatching and countertrading costs as well as congestion prices without additional financial risk.

A market in financial derivatives organised by third parties can offer cross-border hedging possibilities for market participants. CfD (Contract for Differences) is an example of such a product.

Within regions where forward financial markets are well developed and have shown their efficiency, the introduction of PTRs and FTRs shall not be necessary. Financial derivatives not linked to transmission capacity can be considered as an adequate alternative, and be introduced or continued to be used. This is also clearly stated in Regulation (EC) 714/2009."

The IIA mentions as main issues firmness and secondary markets in its analysis of different policy options. The following is said regarding secondary markets (p. 51): *"The establishment of a liquid secondary market is of vital interest to market participants as it provides the capacity owner with an additional option of making unneeded capacity available for the market by receiving a fair price and an additional way for market participants to acquire the needed transmission capacity. TSOs may be responsible for establishing and managing organised secondary markets."*

Financial Transmission Rights are described in the following way in the IIA (p. 54):

"Financial Transmission Rights are transmission rights issued by the TSO as a hedge against congestion costs between zones/countries. With an FTR, the owner does not get the right to physically transport electricity. FTRs entail the right to receive a financial compensation equal to the congestion rent i.e. the price differential between price zones.

FTRs may be designed either as options or as obligations. In this paper, option is understood as the right to receive the positive market price differential. There is no additional obligation on the owner's side. In contrast, FTRs designed as obligations do provide the same right but entail also the obligation for the owner to pay the respective market price differential if it is negative, i.e. if the price differential is in the opposite direction."

The IIA observes that *"it is still not fully clear whether FTRs are linked to financial or legal side effects that have not been identified and assessed yet" (p. 55).*

It is noted in the IIA that *"FTRs require as a prerequisite the implementation of implicit auctions and thus power exchanges" (p. 55).*

Besides only FTRs or only PTRs with UIOSI there are possible combinations of the two instruments. Such a hybrid option is rejected by the IIA with the following explanation (p. 55):

"Operating both systems synchronously would require two separate trading platforms as there two different products would exist – one for FTRs and one for PTRs (with UIOSI). Due to the different allocation systems for these products, the trade would be segmented which consequently triggers less liquidity in both segments while increasing operational costs and thus fees."

2.5 Next steps

The Commission will examine the final draft FG on CACM to see if the framework guidelines meet the criteria of the regulation (see section 2.2 above). The Commission may request ACER to review the framework guidelines within a reasonable period of time and re-submit it to the Commission.

It is interesting to note that ERGEG submitted its first-ever pilot framework guideline in June 2010 to the Commission. The framework guideline was on gas capacity allocation mechanisms. The Commission then had some comments, which had to be taken into account. ERGEG submitted thereafter in December 2010 a revised pilot framework guideline to the Commission. Satisfied that the framework guideline meets the criteria of the regulation, the Commission has now invited ACER to formally submit the framework guideline (by 4 July 2011) and invited ENTSO-G to submit to ACER (by 27 January 2012) a network code, which must be in line with the framework guideline. ACER will now run a 2-month public consultation on the framework guideline although it has already been subject to an ERGEG public consultation.

When the Commission finds that the FG on CACM meets the criteria of the regulation, the Commission shall request ACER to formally submit FG on CACM and ENTSO-E to submit to ACER a network code which is in line with the framework guideline within a reasonable time period. When ACER is satisfied that the network code is in line with the FG on CACM, the agency shall submit the network code to the Commission and recommend that it is adopted. The network code may be legally binding in the member states via comitology.

3 Lessons from PTRs[1]

The Nordic region has limited recent experience with physical transmission rights. Inside the Nordic market, congestion management has been dealt with by means of implicit auctions. Contracts for differences (CfDs) are the main instruments for hedging of what is normally called area price risk. However, at the borders between the Nordic region and Continental Europe, there is some experience with explicit auctions and physical transmission rights.

Whereas CfDs are financial contracts, and from that perspective have similarities with FTRs, they are not issued by the TSOs and TSOs are not part of such contracts. That, however, is the case with the physical transmission rights in and out of the Nordic region. The most relevant experience from the use of PTRs is how the congestion rent is established and shared between the owners of the interconnections (TSOs) and holders of capacity rights (hereinafter referred to as traders).

In the following, we explain shortly the different arrangements used for the German-West Danish border (chapter 3.2) and for NorNed, the Dutch-Norwegian interconnection (chapter 3.3). In chapter 3.4 the numerical results from the two borders are compared and discussed. But first we explain some terms and definitions used in the analysis (chapter 3.1)

3.1 Definitions

When electricity prices differ between interconnected regions (sub-markets) it is due to insufficient transmission capacity between the regions. The value of the electricity flow across a congested line or cut is given by the observed price difference multiplied with the energy volume transmitted (in the day ahead market) from the low price region to the high price region. We define this value as the **congestion rent** and note that it could also be called the socioeconomic ex post value. The owner of the available transmission capacity, or the holder(s) of transmission rights, collects the congestion rent as the cash flow (or revenue flow) related to the asset. The congestion rent is essentially one of the outputs of an implicit auction (or market coupling) algorithm. Due to electrical losses and

[1] All price data used in this chapter are collected from the web sites of Energinet.dk, Nord Pool and APX (NL).

potential ramping constraints, there is a (small) difference between net and gross congestion rent. [2]

Valuation of transmission capacity can be done with different approaches. It is useful to distinguish between an ex post and an ex ante approach. The **ex post cash flow** is simply the congestion rent as explained above. It is of course possible to estimate this cash flow in advance, which is quite common when TSOs (and other) consider investing in interconnections. Such estimates are prognoses or expectations to future congestion rent.

The **ex ante approach** is the real option value of the asset in question. When traders bid for PTRs, they typically bid a high price for the expected optimal direction, and a quite low price for the other direction. While the first bid is assumed to capture the direction that most likely corresponds to the difference between day-ahead prices (from low-price to high-price region), the latter bid is because of the possibility of erroneous expectations. Sufficiently long time ahead of the delivery hour (e.g. several months), there might be high uncertainty about optimal direction. Thus potentially, the ex ante value can be equal in both directions.

The **interconnector cash flow** can be considered as the sum of two components when PTRs are involved. Traders pay their real option valuation of the transmission capacity to the TSO. Afterwards, they may collect the cash flow as their revenue, and end up (hopefully) with a profit. Hence, the following expression holds:

$$Interconnector\ cash\ flow = real\ option\ value + trader\ profit$$

Note that it is possible to value any option higher ex ante than it's ex post value. As a result, the traders' profit may be negative, and the congestion rent may be lower than what TSOs have collected in PTR auctions. However, over time, it is fair to assume that trader's bids for PTRs would be adjusted so they end up making profits.

The interconnector cash flow is not necessarily equal to the congestion rent. Due to flaws in market design (e.g. requiring traders to make firm decisions on volume before day-ahead prices are known) or traders' failure to adjust volumes when prices are known, the cash flow can be significantly lower than the congestion rent, see Figure 3-4 for an example.

[2] Gross congestion rent equals the available transmission capacity multiplied with the absolute value of the price difference between the interconnected markets (calculated hour by hour, and then aggregated for all hours). The cost of a ramping constraint can be measured by the difference between the gross congestion rent and the rent calculated when replacing the available transmission capacity with the planned or scheduled utilisation of the interconnection (in the day-ahead market).
The cost of the electrical losses can be calculated as the planned utilisation multiplied with the loss factor for the interconnection and the lower of the two electricity prices.

In order to fully illustrate the different concepts and names, it can be useful to have a closer look at few specific hours, and follow the timeline of the trade and cash flow. We've selected a working day, Monday January 11, 2010, and will study the prices and trade across NorNed. Figure 3-1 below shows the day-ahead prices in the Netherlands and Norway, as they turned out to be after the NorNed capacity auction. As from hour number 2 until hour number 8, the Norwegian prices were higher than the Dutch. From hour number 8 until hour number 22 the Dutch prices were highest.

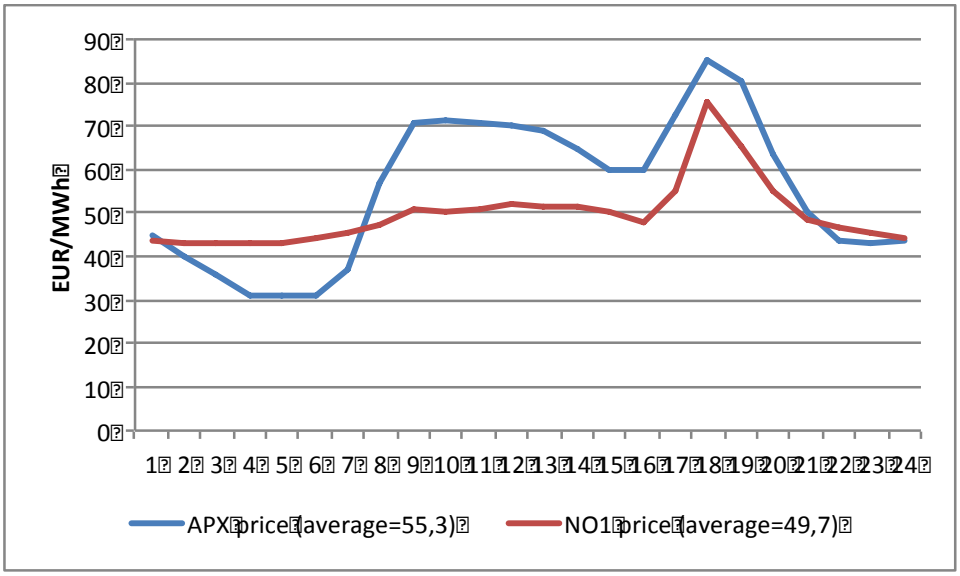


Figure 3-1 Day-ahead prices, January 11, 2010

The price expectations must have been slightly different. In Figure 3-2 below, we have plotted the price difference between Norway and the Netherlands (blue line) and the auction price (green line). For hour number 1, the auction price is negative, indicating that traders paid (2.79 EUR/MWh) for capacity from the Netherlands to Norway. This implies[3] that traders expected the Norwegian price to be highest for this hour. However, the Dutch price turned out to be the highest (1.35 EUR/MWh above the Norwegian price), and traders made a loss for this hour: They had purchased a service, transport capacity from south to north, that in fact turned out to have a negative value, losing an extra EUR 1.35 for each MW sent in that direction. Their total loss was 4,14 EUR/MWh for such a nomination.

[3] See chapter 3.3 for an explanation why a negative price implies that expectations were that Norwegian prices were highest. At NorNed, only the highest valued direction will be sold.

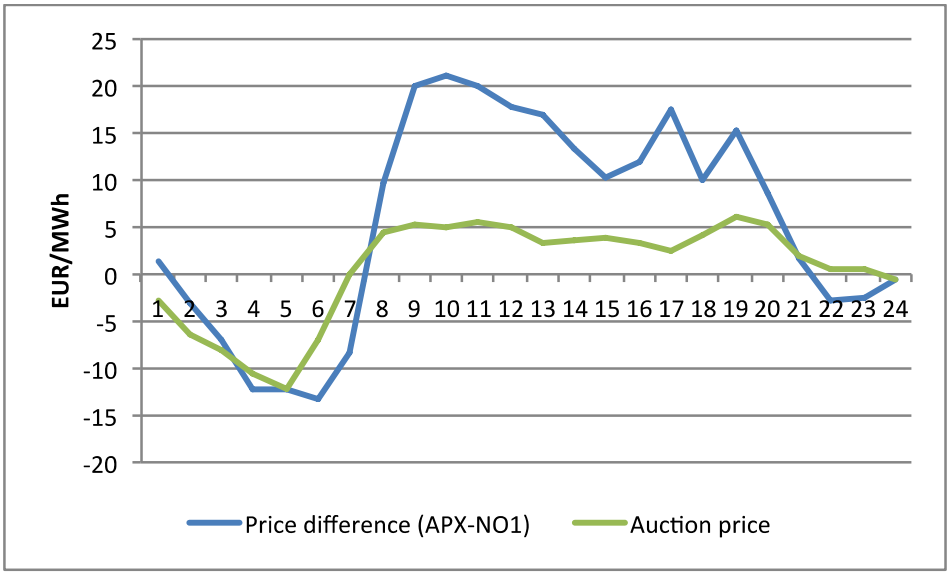


Figure 3-2 Price difference and auction price, January 11, 2010

As the auction price is sunk cost after the closure of the NorNed auction, the best strategy for a trader to minimise losses (if he then knew the prices), would be to not use the capacity – limiting the losses to 2.79 EUR/MWh. The challenge is of course, that when the APX closed, the traders did still not know the Norwegian price but had to make a commitment in the Dutch market. Depending on the nature of this commitment and available options after the Norwegian price was settled (normally at 13:00), it could still be least costly to make use of the purchased capacity. In fact, the traders' nominations for the "wrong" direction totalled at 525 MW for hour 1.

The total loss (for the traders), which can be assigned to the decision of purchase the PTRs and nominate use of PTRs, was equal to 700*2.79+525*1.35 = 2 661.75 EUR for this particular hour, see Figure 3-3 below. However, for the whole day, traders' net revenue was EUR 87 382, while the TSOs revenue was EUR 72 448. The congestion rent net of the ramping constraint was EUR 170 482. The reason why the congestion rent is not exactly the sum of traders' and TSOs' revenue, is that the congestion rent is the ex post value of the trade, while the latter is a combination of the ex ante valuation made by traders and their utilisation of the capacity purchased (ex ante). As suboptimal trades are possible, the sum of traders' and TSOs' revenue may be lower than the ex post congestion rent.

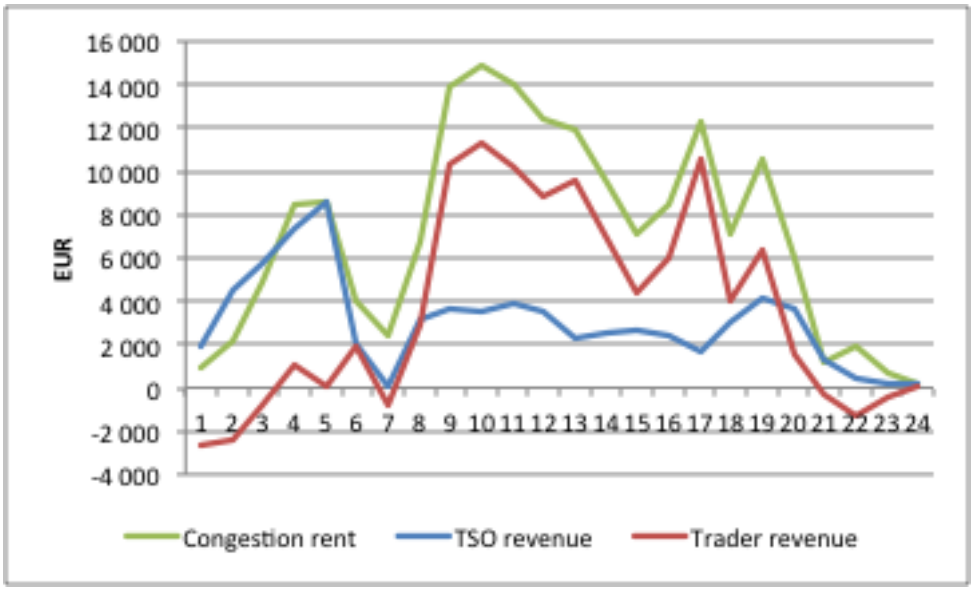


Figure 3-3 Allocation of revenue, January 11, 2010

3.2 Western Denmark – Germany

The western part of Denmark and Germany are interconnected with 420 kV AC-lines. The transmission capacity is currently 1500 MW southwards and 950 MW in the northern direction. The capacity is controlled and managed by Energinet.dk and TenneT TSO GmbH.

The TSOs offer PTRs of yearly and monthly durations. Currently, the capacity for the annual auction is 200 MW in both directions (as separate contracts). Monthly auctions also cover 200 MW in each direction. The remaining capacity, including not utilised PTRs sold in annual or monthly auctions, has been offered in daily auctions.

The time-line of trade is such that holders of long-term (year or month) PTRs must nominate their intended use of their rights every morning. Until November 11, 2009, any available capacity after this was offered in a day-ahead auction, closing at 10:00. After this date, the remaining capacity is allocated for the implicit market coupling between Germany and Denmark.

3.3 NorNed

The Dutch-Norwegian interconnection NorNed has been in operation since May 6, 2008. When Statnett and TenneT applied for the necessary licences, they applied for an interconnection fully owned and operated by the TSOs. The original plan was to have implicit auctioning of the capacity, and utilise the capacity in the day-ahead markets. However, implicit auctions were postponed until 12 January 2011.

During the interim stage, TenneT and Statnett practised a unique design of explicit auctions for NorNed. There are several features of the auctions that made them unique:

1. There were only day-ahead auctions. Traders cannot purchase long-term capacity products.
2. Traders could purchase physical transmission rights (PTRs), separately for each hour the next day.
3. The TSOs sold only capacity in one direction for each hour. Selection of direction to be auctioned was based on the bids; the most attractive bids set the direction (though there are some minor adjustments due to ramping constraints).

Capacity information was released every day no later than 09:15, bids could be placed until 09:45, and the results were published at latest at 10:15. Successful bidders had to nominate their intended use of the capacity no later than 14:00 in the Dutch system. In the meantime, they could plan and trade as they wished at both spot exchanges.

The PTR auction was a single bid sealed auction. However, a participant could place several bids, e.g. a high price for a small quantity and a low price for a large quantity. If the market-clearing price was higher than his low bid, but lower than his highest bid, the small-quantity bid was awarded. The auction price was set at the lowest activated bid (marginal bid).

3.4 Interconnector cash flow vs congestion rent

Based on data for PTRs towards the Netherlands and Germany, we have calculated the total auction revenue for the TSOs (which normally is split 50/50 between the TSOs involved), the net profit for traders participating in the auctions (though not including their own internal costs), and the congestion rent, which is the socioeconomic ex post value of the auctioned capacity.

Figure 3-4 shows the traders' profits (red line), the TSO revenue (blue line), and the congestion rent between Germany and Denmark from 2006 and until the end of 2010. The TSO revenue is what the traders have paid to the TSOs for the PTRs. The TSOs' income from market coupling (since November 2009) is not included in the figures. The figure shows that both the congestion rent and the TSO revenue rose steadily from 2006 until January 2009. The slope changes around January 2009 and for both TSO revenue and the congestion rent the slope gets less steep. The traders' revenue rose steadily the first year, thereafter a little loss and since January 2009 their profit has been approximately zero. This illustrates that the recession and the reduced fuel prices resulted in much lower price differences in 2009 than anticipated in the annual auction for 2009.

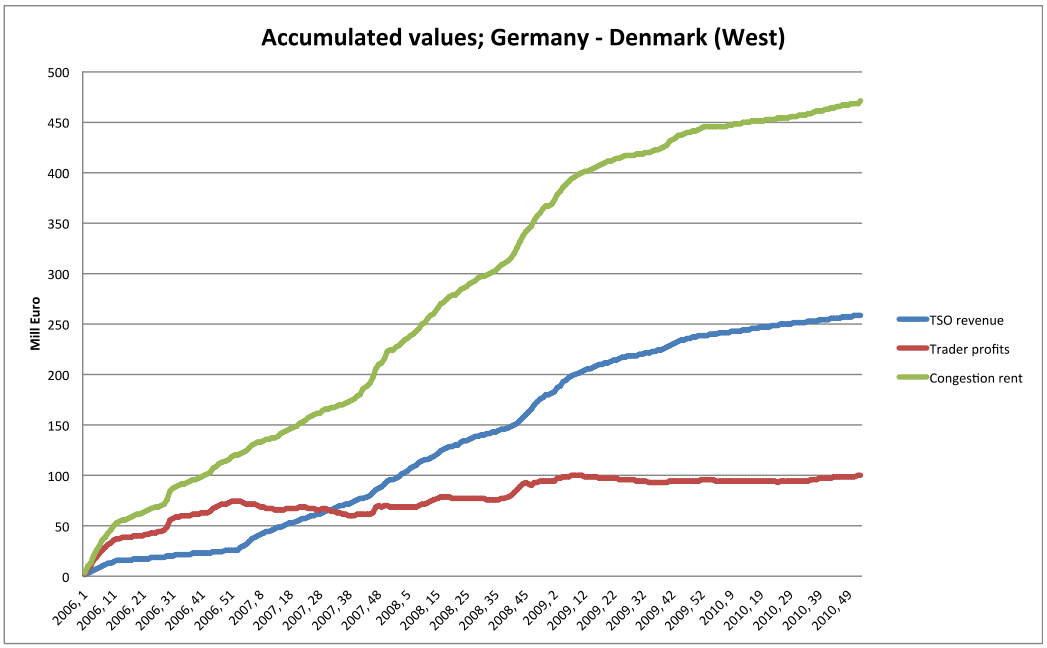


Figure 3-4 Congestion rent and interconnector cash flow between Denmark and Germany

From Figure 3-4 we can see that whereas the congestion rent over 5 years is more than 450 million Euros[4], the traders' gross revenue (trader profit plus payments to TSO) has only reached 350 million Euros.

Figure 3-5 shows the deviation between the congestion rent and the sum of traders profits and TSO revenue, measured as Euro per week. Every value above zero is where the congestion rent is higher than the sum of the other, and thus represents a loss for the society (due to insufficient utilisation of the transmission capacity). Note that the loss has been much lower since the day-ahead capacity auctions ceased in November 2009 and the remaining capacity was instead allocated to the implicit market coupling.

[4] There is chance that the true figure would have been lower. One cannot rule out the possibility that market coupling would have resulted in smaller price differences than actually observed. But that does not affect the socioeconomic value of the capacity – only the distribution of that value among market participants.

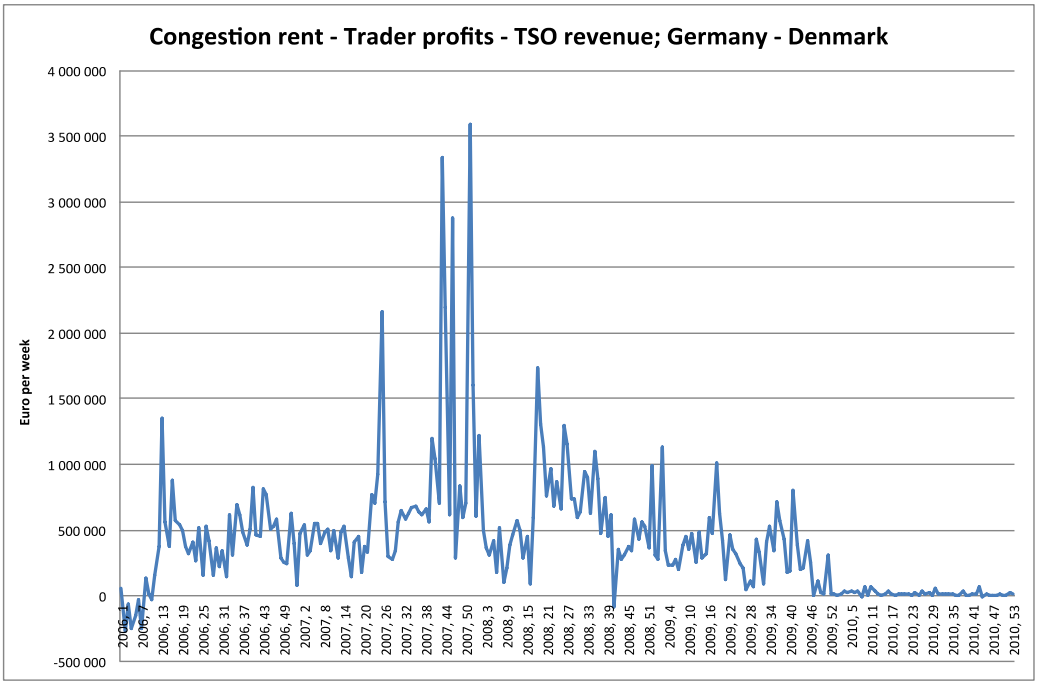


Figure 3-5 Deviation between theoretical value and actual value between Germany and Denmark

Figure 3-6 below shows TSO revenue, trader's profits and the congestion rent between Norway and the Netherlands from week 19, 2008 until the end of 2010. The diagram shows that both the congestion rent and the TSO revenue rose steeply the first year, but then the pattern changed in January 2009. The slope of both curves gets less steep. It seems as the traders' profits have been quite stable on a weekly basis.

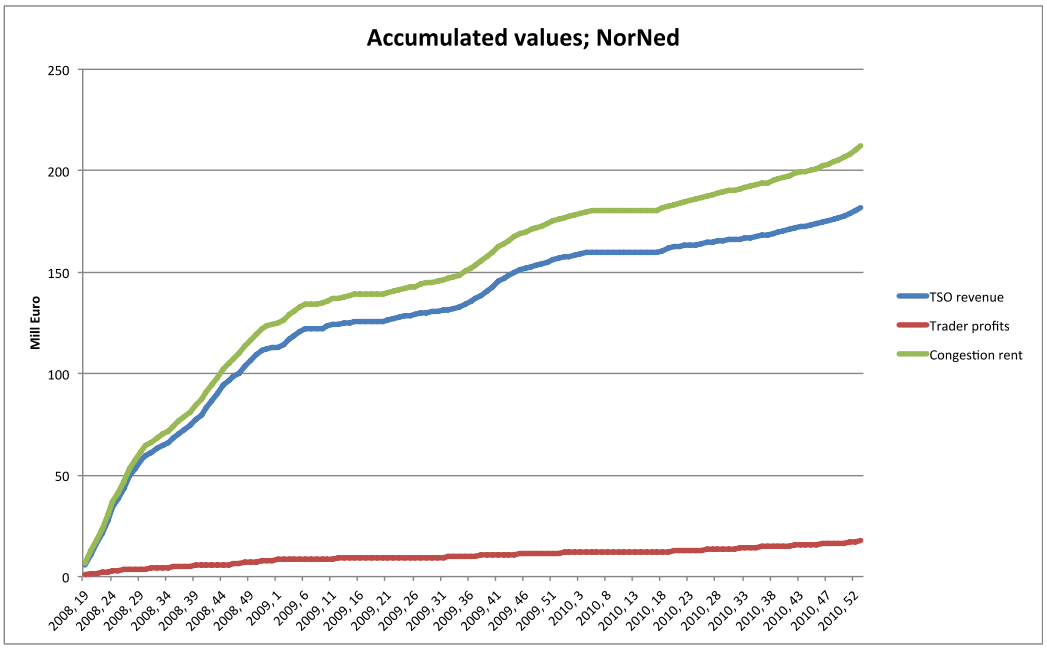


Figure 3-6 Congestion rent and interconnector cash flow Norway and the Netherlands

Figure 3-7 shows the deviation between the congestion rent for NorNed and the sum of traders' profits and TSO revenue. Every value above zero is where the congestion rent is higher than the sum of the other.

The losses measured in Figure 3-5 and Figure 3-7 are removed with the introduction of market coupling.

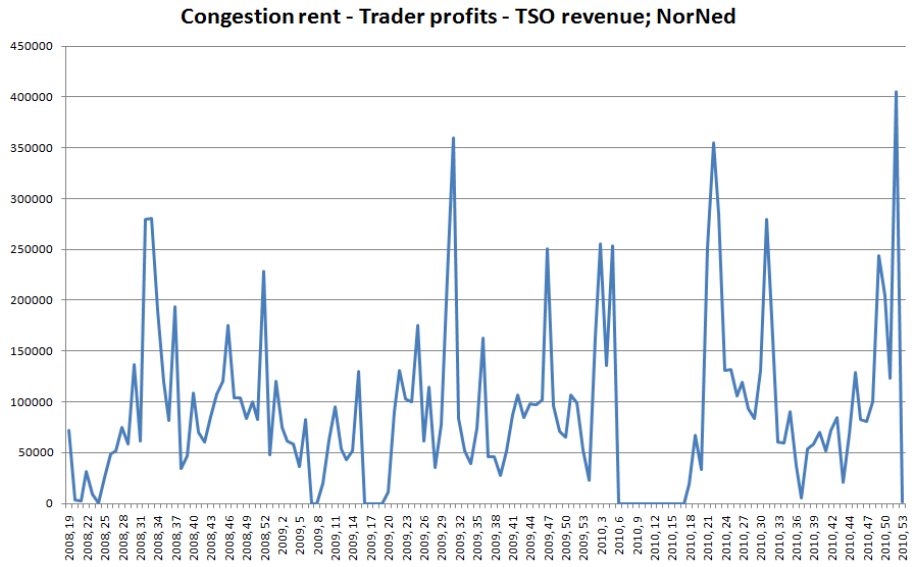


Figure 3-7 Deviation between theoretical value and actual value between Norway and the Netherlands

4 Lessons from CfDs

The Nordic system price is the reference price for most of the contracts in the Nordic financial electricity market. The system price is calculated by Nord Pool Spot in the common day-ahead auction for the Nordic countries. It states the common Nordic price that would have been achieved in the spot market if there were only one bid area for the whole Nordic area.

Presently there are five bid areas in Norway, two in Denmark and one in Finland respectively Sweden. Sweden will from 1 November 2011 be divided into four bid areas. Different area prices arise if there are congestions between different bid areas.

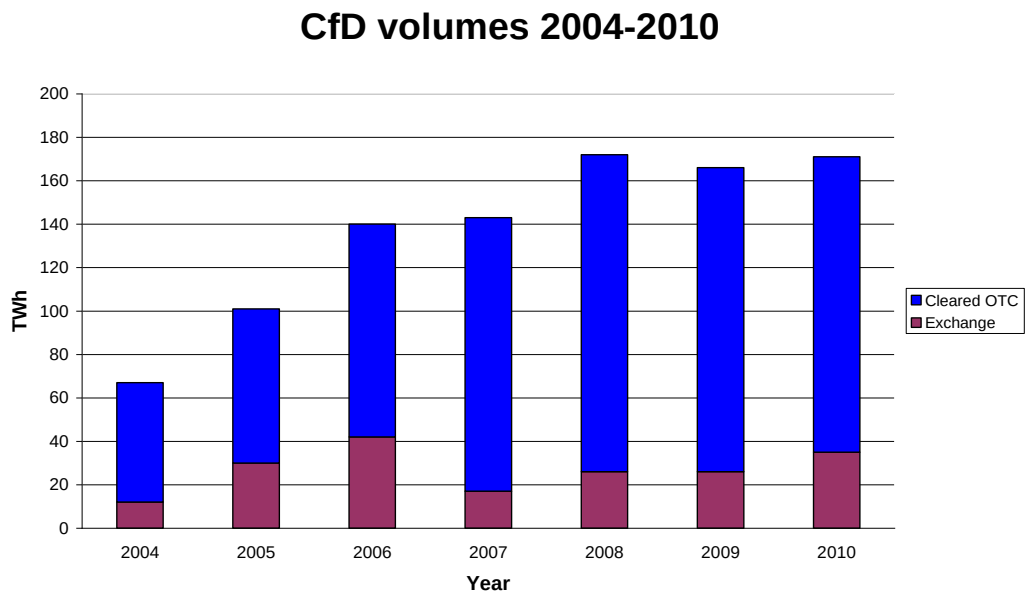
This means that there is also an area price risk for the Nordic market players in addition to the system price risk. One possibility to manage the two risks is a combination of CfD-contracts and normal financial contracts with the system price as the reference price. Another possibility is to use bilateral area price contracts instead of the combination of system price contracts and CfD-contracts. The reference price for bilateral area price contracts is normally the area price in the local currency. A third possibility is that the market player keeps the area price risk and that he hedges the system price risk with system price contracts.

Nord Pool introduced CfD-contracts in 2000. A Nordic CfD-contract is a contract regarding the difference between a certain area price and the system price. The exchange-listed CfD-contracts have been regarding Copenhagen (Eastern Denmark), Århus (Western Denmark), Helsinki (Finland), Stockholm (Sweden) and Oslo (South-Eastern Norway). There are CfD-contracts for months, quarters and the three nearest calendar years. CfD-contracts for the new Swedish price areas Luleå, Sundsvall and Malmö and for the Norwegian price area Tromsø were listed in November 2010.

NordREG published in November 2010 the report *The Nordic financial electricity market (Report 8/2010)*. One part of the report describes the development of exchange trade and cleared OTC trade in the Nordic market. There is no transparency regarding uncleared OTC trade but the report cites guesses from interviewed market players that at least 90 % of the OTC trade in exchange-listed contracts is reported for clearing.

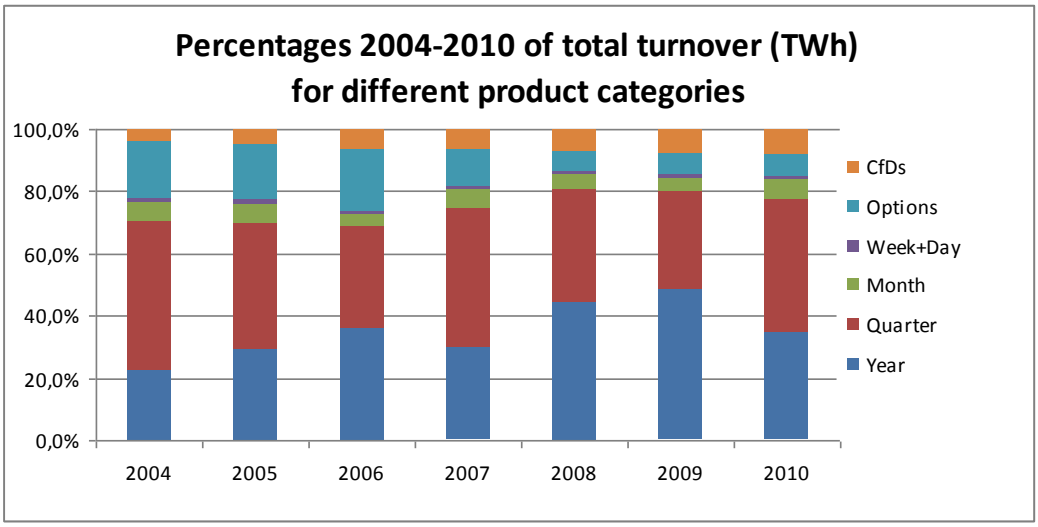
Our graphs and our description of the CfD market in this section are based on the graphs and the description in the NordREG report. New data regarding 2010 has been provided to us by Nasdaq OMX Commodities.

The following graph shows for CfD-contracts how exchange trade and cleared OTC trade have developed during 2004-2010.



The figure shows that most of the trade in CfD-contracts is done OTC. This is a difference against other product categories in the financial market. Most of the trade in quarter contracts and short-term contracts (months, weeks and days) is done on the exchange. The trade in year-contracts is split even between OTC and the exchange. On the other hand, nearly all the trade in option contracts is done OTC. One explanation for the low market share for the exchange in CfD-contracts and option contracts is that these products are not traded so intense as the short-term products and the year-contracts. An intense trade results normally in a very small spread between buy and sell bids on the exchange. However, the added value that can be received from brokers is bigger when the trade is not so intense and the spreads are not reduced on the exchange screen.

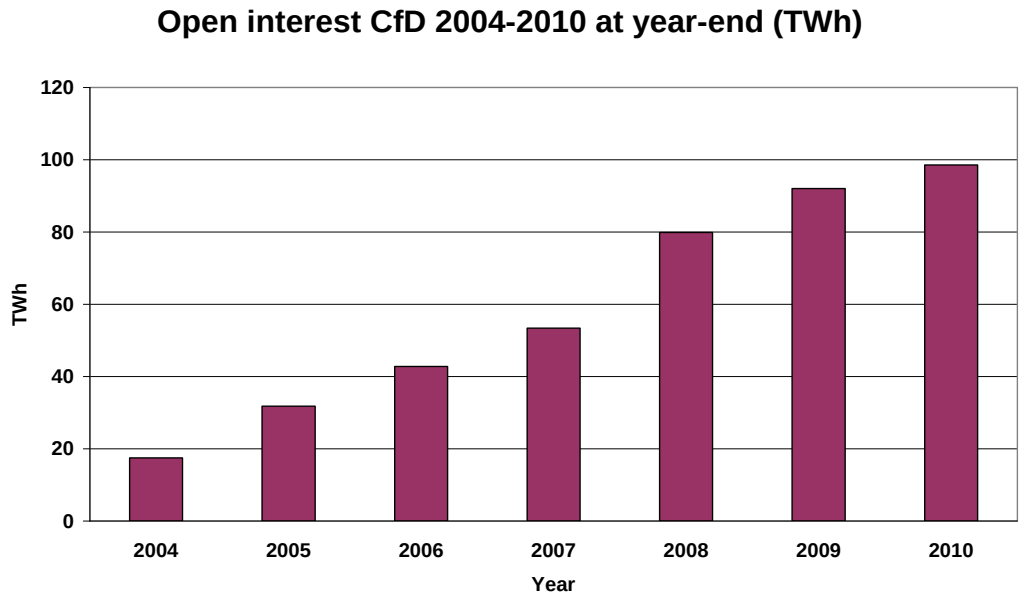
The difference between different years reflects partly the general liquidity development in the Nordic market. Trade volumes increased 2004-2008 and reduced from 2008 to 2009 because of the general financial crisis. The following graph shows for the different product categories how their percentages of total cleared turnover have developed 2004-2010.



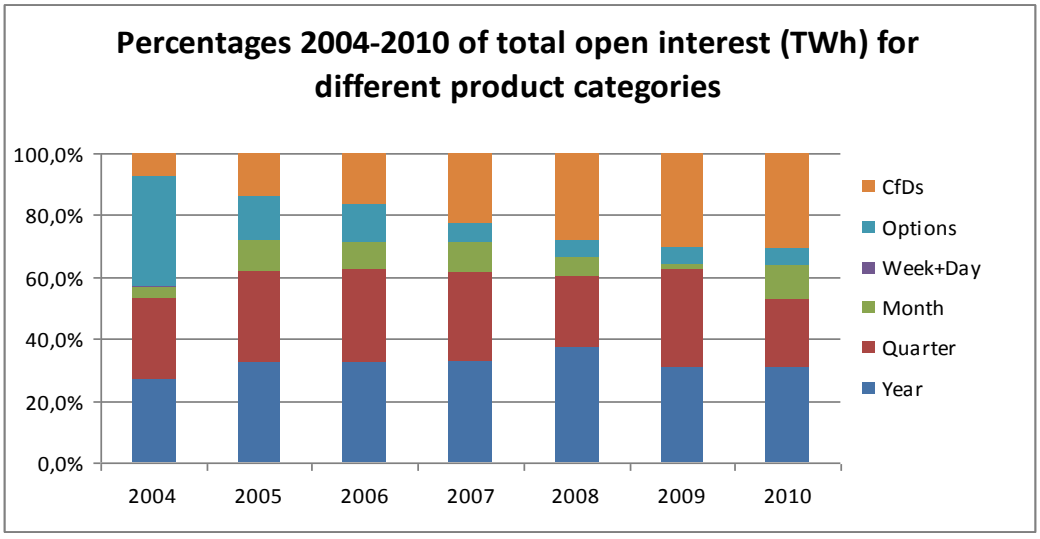
The graph shows large changes in the turnover shares for different product categories. The share of CfD-contracts doubles from 4 % in 2004 to 8 % in 2010. The share of option contracts falls to only one third of the share in 2004 (from 18 % in 2004 to 7 % in 2010). The share of year contracts increases from 22 % in 2004 to 35 % in 2010. The share of quarter contracts is reduced with one third from 48 % in 2004 to 43 % in 2010. The share of short-term contracts (months, weeks and days) is about the same, 8 % in both 2004 and 2010.

The clearing house (earlier Nord Pool Clearing ASA, now NASDAQ OMX Stockholm AB) becomes the counterparty to both the buyer and the seller once a trade is done on the exchange or once an OTC trade is registered for clearing. The clearinghouse nets (offsets) the portfolio of positions a market player has entered into regarding each contract. The net position of the market player regarding a certain contract is its open position with the clearinghouse. A short-term trading company has normally small open positions in relation to its total trading. A trading company, which takes long-term positions, can have bigger open positions with the clearinghouse in relation to its total trading. A producer or a consumer who performs multi-year hedges can even have a bigger open position than its trade during the year.

The sum of all open buy positions (or all open sell positions) with the clearinghouse is the open interest of the clearinghouse. The net sum of all open positions with the clearinghouse is zero since the clearinghouse always becomes the counterparty to both the buyer and the seller. The following graph shows for CfD-contracts how the open interest volume at year-end has developed 1998-2010.



The graph shows for CfD-contracts a rapid increase in open interest volumes. The increase in open interest volumes is more rapid for CfD-contracts than for other product categories. This is shown in the following graph.



The graph shows that the share of total open interest quadruples for CfD-contracts from 7 % in 2004 to 31 % in 2010.

If a product category has a higher share of open interest than of turnover, it indicates that much of the turnover in the product category is hedging or long-term trading. A lower share of open interest than of

turnover indicates on the other hand that much of the turnover in the product category is short-term trading.

CfD-contracts have a much higher share of total open interest than of total turnover. Such contracts made up 31 % of the total open interest at year-end 2010 and 8 % of the total turnover in 2010. This indicates an extensive hedging in CfD-contracts and small short-term trading in such contracts.

The differences for year and quarter contracts are more statistical. The contract for the next year is at year-end cascaded into quarter contracts. This means that e.g. the year contract for 2011 is a major part of the turnover of year contracts in 2010 but the open interest in the contract is at year-end included in the open interest of quarter contracts since the contract at year-end has been cascaded into quarter contracts. The share 31 % for year contracts at year-end 2010 means thus that the year contracts for 2012-2015 made up 31 % of the total open interest at year-end 2010.

One very interesting conclusion from the graph regarding shares of open interest for different product categories is consequently that the open interest volume at year-end 2010 was split in three equal parts besides 5 % in option contracts. These three equal parts were system price contracts regarding 2011, system price contracts regarding 2012-2015 and CfD-contracts regarding 2011-2013.

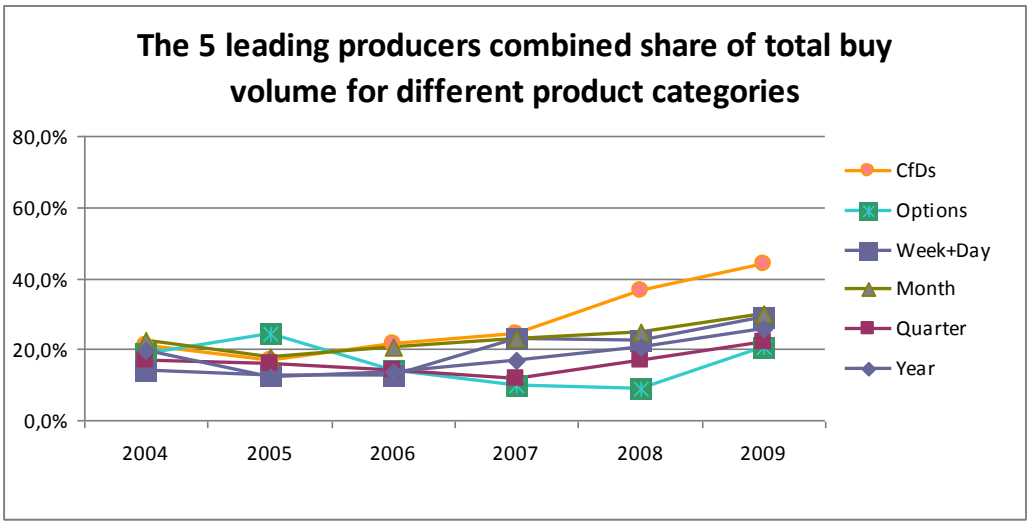
The extent of hedging in CfD-contracts can be illustrated by the following data regarding the open interest by the end of January 2011. The open interest in system price contracts for February 2011 was 14 188 MW and the open interest in CfD-contracts for February 2011 was 10 747 MW. These figures indicate that about 75 % of the basic hedging in system price contracts is before the delivery period supplemented with area price hedging in CfD-contracts.

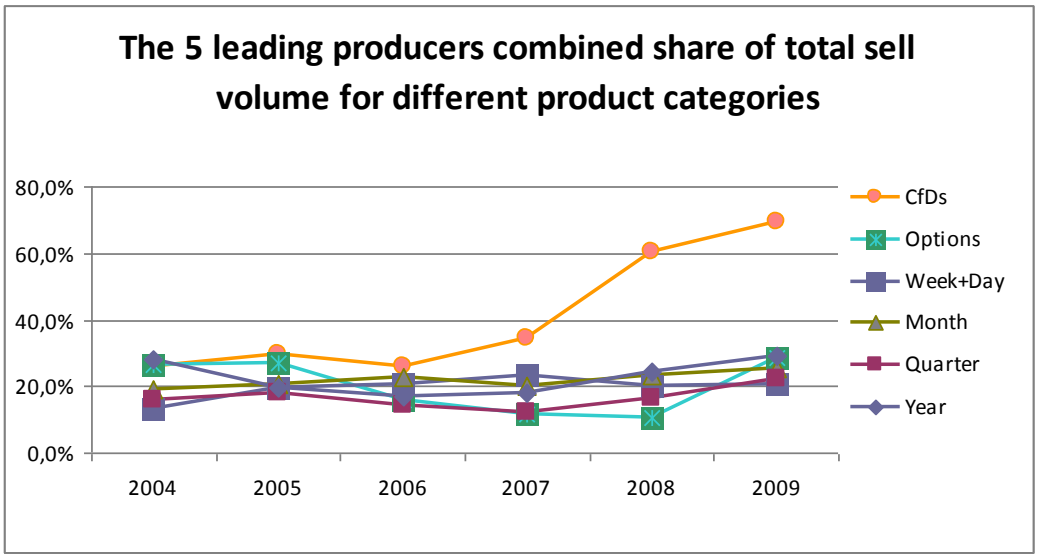
The open interest in system price contracts for calendar year 2012 was 7 543 MW in the end of January 2011 while the open interest in CfD-contracts for calendar year 2012 was 3 188 MW. The open interest in system price contracts for calendar year 2013 was 3 357 MW at the same time while the open interest in CfD-contracts for calendar year 2013 was 1 055 MW. This indicates that the longer horizon for basic hedging in system price contracts, the smaller is the share that is supplemented with area price hedging in CfD-contracts.

It is also interesting to note that the share of CfD-contracts in relation to total consumption is nearly the same in Sweden, Finland and Denmark while it is much smaller in Norway. The distribution of the open interest in CfD-contracts for February 2011 was in the end of January 2011 the following: 5 408 MW in Swedish contracts, 3 222 MW in Finnish contracts, 1 478 MW in Danish contracts and 639 MW in Norwegian contracts.

One explanation for the low Norwegian share is that many Norwegian retailers and consumers have perceived the area price risk as relatively small and therefore not been so focused on the area price risk as retailers and consumers in Sweden, Finland and Denmark. Another explanation is that the extent of fixed price contracts in relation to variable price contracts is much smaller in Norway. A third explanation is that many integrated regional companies in Norway have performed bilateral hedging between their generation and retail businesses. A fourth explanation is that the Norwegian practice of changing the demarcation lines and numbers of bidding areas according to (stochastic) changes in congestions in the (domestic) transmission grid, does not ensure that a specific CfD provides hedging – it is only a few weeks time ahead of delivery one can be really sure about which bidding area one point belongs to. And a fifth explanation resembles to the old question about who came first of the chicken and the egg; with low liquidity there is low interest in using the instrument for hedging, and with low interest for hedging there is low liquidity.

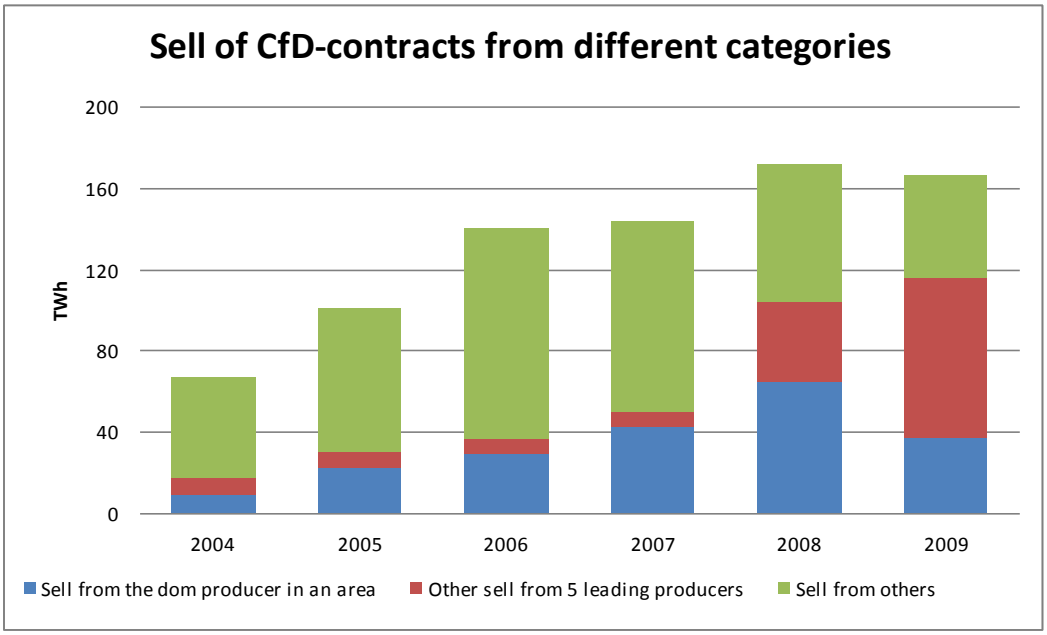
The NordREG report looked also into the market concentration in the Nordic financial electricity market. The report presented different measures of the market concentration since company-specific information regarding exchange trade and cleared trade is not public. One of these measures is the combined share of Dong, E.ON, Fortum, Statkraft and Vattenfall (the 5 leading producers). The following two graphs show for different product categories the 5 leading producers combined share of total buy volume and total sell volume.





The two graphs show with one exception that the combined share for the 5 leading producers is nearly the same for the different product categories. The exception is CfD-contracts where the 5 leading producers have a higher share of total buy volume and especially a higher share of total sell volume. It can be noted that the combined share of the 5 leading producers was much higher in 2008 and 2009 than earlier.

The fact that the 5 leading producers in 2008 and 2009 got such a high combined share of the supply of CfD-contracts is problematic if it reflects near monopolistic sell of CfD-contracts in the different areas. NordREG asked therefore for a separation of the sell from the dominant producer in an area from other sell by the 5 leading producers. The requested volume shows how much of total sell of CfD-contracts that originates from sell by Statkraft in Oslo-contracts, Vattenfall in Stockholm-contracts, Fortum in Helsinki-contracts and Dong in Copenhagen- and Århus-contracts.



The graph shows that the sell of CfD-contracts from other companies than the 5 leading producers is every year bigger than the sell from the dominant producer in an area. In addition the dominant producer in an area faces also competition from the other leading producers. The increase in 2008 and 2009 in sell of CfD-contracts from the 5 leading producers is in other countries than the country where they are the dominant producer. Such a supply in other countries from the 5 leading producers broadens the competition in the CfD-market and reduces the risk of near monopolistic sell of CfD-contracts.

NordREG interviewed 13 market players regarding risk management and the functioning of the Nordic financial electricity market.

All interviewed market players were satisfied or very satisfied with the general functioning of the Nordic financial electricity market. There are many players in the market with different trading approaches and different hedging needs. The market is seen as very transparent and a high share of the contracts is traded electronically. The linkage to the physical market is seen as well-functioning and makes efficient pricing and symmetric information possible. However, the market players have not full trust in the prices when the market is divided into separate price areas. High barriers for new baseload physical production and the low bidding of demand elasticity into the spot market are also mentioned as problems in the physical market.

The financial settlement during the delivery period is seen by many as a real strength for the Nordic financial electricity market. Traders do not have to be concerned about transit arrangements, nominations

and other operational issues as in many other markets. Customers and retailers can easily have separate hedging positions related to their physical contracts also during the delivery period.

The interviews presented in the NordREG report show that area price risk management has become a much more important part of risk management strategies, especially for retailers in Denmark, Finland and Sweden but also for customers in these countries. The Norwegian interest in CfD-contracts has so far been much smaller than the interest in the other three countries. One reason is that the market share for fixed-price retail contracts is much lower in Norway than in the other Nordic countries. Retailers and consumers in South Norway have also less incentive to hedge the area price since they often expect the area price to be lower than the system price.

It is noted that it is always possible to make a trade through the exchange since there are market makers in all Nordic contracts (except Oslo CfD-contracts). However, several market players state that there is a liquidity problem in the supply of CfD contracts. They see asymmetric interests in the buying side and the selling side of CfD-contracts. The areas are also seen as too small for a real market to develop.

5 Possible design of FTR instruments in the Nordic countries

5.1 FTR instruments in the US

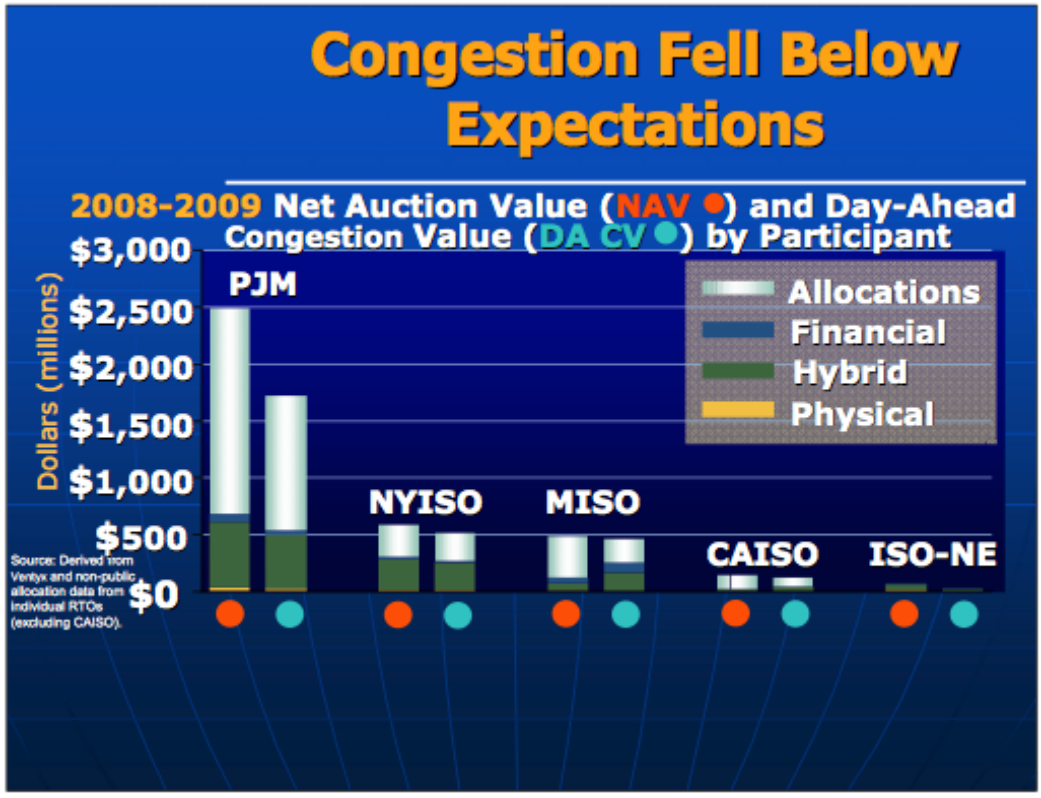
PJM is the largest transmission operator in North America. The annual consumption is over 700 TWh. The area has grown from Pennsylvania-New Jersey-Maryland and covers now all or parts of 13 states in eastern USA. PJM has during long time developed a market for transmission rights. Some other regional transmission operators (RTOs) have also developed markets for transmission rights.

One driving force for this development is that the transmission network is by the energy regulators seen as financed by the customers. Congestion rents because of an introduction of nodal pricing should thus be transferred to the customers and not be a profit for the transmission company. RTOs allocate therefore congestion revenues because of nodal pricing through different instruments to load-serving entities (LSE).

PJM organises now FTR auctions. Both FTR options and FTR obligations can be bought. The bids are approved in such a way that the total income from the auction is maximised. The income from the auction goes to the holders of Auction Revenue Rights (ARRs). The purpose is that the ARRs shall provide revenues to LSEs to offset their purchases of FTRs. When retail load switches between LSEs, a proportional share of the ARRs and their associated revenue is reassigned from the LSE losing load to the LSE gaining load.

FTRs are financial instruments that entitle the holder to revenues based on the hourly day-ahead price differences. FTRs are bought for hedging purposes by utilities and customers. They are also bought by entities that want to take a financial position. Financial entities own 43 % of all annual FTRs according to the 2009 State of the Market Report for PJM. They own a higher percentage of counter flow FTRs than of prevailing flow FTRs.

There are differences in the design of FTRs between different RTOs. They are called congestion revenue rights (CRRs) in California and Transmission Congestion Contracts (TCCs) in New York. FERC (Federal Energy Regulatory Commission) presented the following graph in its State of the Markets Report 2009.



Source: State of the Markets Report 2009, FERC, April 15, 2010

The graph shows the net auction value 2008-2009 for different RTOs. It shows also that most of the FTRs are still allocations. The actual day-ahead congestion value was especially in the PJM area much lower than the auction value. Reduced electricity demand in 2008-2009 because of recession and reduced fuel prices meant that the actual congestion value were lower than the expected value.

5.2 European positions regarding FTRs

The proposed target model for forward markets from PCG was that TSOs should issue transmission rights on a forward basis (see section 2.3 above). In case of physical rights, they should be granted as options with use-it-or-sell-it (UIOSI). In case of financial rights they could be either options or obligations. The transmission rights should be able to be split and resold without constraints – down to individual hours and in 1 MW units.

The draft FG on CACM says that PTRs shall be options and subject to UIOSI (see section 2.4 above). FTRs may allow for both possibilities (options or obligations).

Several of the responses to the consultation on FG on CACM discuss the need for and the design of FTRs.

EFET (the European Federation of Energy Traders) states that FTRs or PTRs must be implemented in a consistent way between all bidding zones in all parts of Europe and that the Guidelines must clearly state that all TSOs shall allocate FTRs or PTRs. TSOs must sell transmission rights forward using the same timeframe as those used for trading electricity in the commodity markets. They view a transmission right as an option on the spread between two markets, which is (if no action is taken) automatically cashed out at day ahead stage on the power exchanges.

EURELECTRIC points out the need for a stricter alignment of the draft FG on CACM with the target model adopted by the Florence Forum in December 2009. One example of apparent inconsistency between the draft Guidelines and the target model is the provision 3.2 (4.2 in the final draft), that weakens the need for PTR or FTR issued by the TSOs in case "appropriate cross-border financial hedging instruments are offered in liquid financial markets". This is not in line with the target model adopted by the Florence Forum in December 2009, stating that TSOs shall issue PTRs or FTRs. Various market instruments, like CfDs in the Nordic market, can be provided by the market, but they can not be regarded as a replacement for the TSOs obligations to offer cross-border capacity to the market.

E.ON stresses that long-term capacity products at the border of price/bidding zones are essential for hedging of production and sales. Financial Transmission Rights (FTR) and Physical Transmission Rights (PTR) are important for cross-border competition in the forward markets. E.ON believes that TSOs should allocate FTRs or PTRs corresponding to the full available capacity. A system of Contracts for Differences (CfD), as used in the Nordic market, is not fulfilling the requirements to enable cross-border competition in the forward market between fundamental competitors. This needs to be reflected in the framework guidelines to ensure that exceptions are not allowed that will hinder competition.

RWE states that the TSOs should allocate as much capacity as possible to the forward market to facilitate retail competition across borders. Transmission products should normally be sold as rights rather than obligations since this will allow value to be maximised for the benefit of consumers. Transmission rights should be allocated in a co-ordinated way, preferably by a single auctioning office. This requires consistency of processes and definitions.

Vattenfall concludes that the preferred long term capacity products should be FTRs. In the future, FTRs should replace any existing physical rights currently auctioned in Europe. As FTRs rely on

locational prices, a transition from physical rights requires that reliable price references are established and that all day-ahead capacity between areas is managed centrally by power exchanges. The ERGEG suggestion not to allow different types, i.e. both options and obligations together on a particular border is not regarded as the most feasible solution. Instead, the TSOs should auction FTRs as obligations and options, distribution decided in the auction based on market players' bids.

EnBW sees a liquid wholesale market for up to three years ahead. Thus, in order to allow long-term hedging possibilities, multi-year capacity products issued by the TSOs – in accordance with the products in the energy market (y+3; y+2; y+1) – are essential. Regarding the products, EnBW agree that FTRs or PTRs (with UIOSI) are the preferred long-term products for the forward market timeframe allocated by the TSOs. EnBW do not agree that other instruments such as CFDs are considered as equivalent instruments as they do not have any link to the underlying physical transmission capacity.

The German Association of Energy and Water Industries (BDEW) believes that FTRs or PTRs shall be implemented in a consistent way between all bidding zones in all parts of EU. The framework guidelines shall state that all TSOs shall allocate FTRs or PTRs corresponding to the full available capacity. It is the freedom of the market to have other instruments in place, like CfDs in the Nordic market, but they should not be considered as a replacement for the TSO obligations. The reason for this is that they are not fulfilling the requirements to enable cross-border competition in the forward market between fundamental competitors.

The Association of Austrian Electricity Companies (Österreichs Energie) believes that FTRs or PTRs shall be implemented in a consistent way between all bidding zones in all parts of EU. The framework guidelines shall clearly state that all TSOs shall allocate FTRs or PTRs corresponding to the full available capacity. CfDs, as used in the Nordic market, are not fulfilling the requirements to enable cross-border competition in the forward market between fundamental competitors.

EDF concludes that all the timeframes should be more detailed in the Draft Framework Guidelines. The day-ahead timeframe, for its central position in the price formation, and the intraday, due to the increasing importance that this timeframe will have and the low level standards currently implemented, should be prioritized. EDF considers that FTR could be an interesting target that is only achievable if day-ahead markets are coupled and if market parties have gained confidence in the coupling function. For the time being, PTR with the UIOSI principle seems acceptable provided that the TSOs are committed to increase capacities dedicated to the day-ahead coupling. Longer-term products

such as 2 to 3 years FTRs or PTRs should also be studied as an additional tool to develop competition.

Edison, Italy's second largest generator, says that the introduction of PTR with UIOSI and the development of secondary markets for capacity go in the right direction towards a balance between transmission capacity allocated long-term and an appropriate level of capacity released for day-ahead and intraday electricity exchanges. To this end, the development of well-functioning secondary market platforms seems to be a primary condition. Also FTR, designed as options, can be a viable solution especially where day-ahead markets are coupled.

Iberdrola believes that CfDs can become an efficient solution for the specific case of an interconnection with a lack of liquidity in one of the markets. Therefore, CfDs would enable the more liquid market to introduce a higher level of competition at retail level in the less liquid market. This is the case of Spain and Portugal, where CfDs have allowed competition in the Portuguese retail market despite having an illiquid forward market.

Iberdrola points out some aspects that make PTRs + UIOGPFI ("use it or get paid for it") be ahead of FTRs. One of these aspects is that FTRs require participation on the spot markets to be able to undo long–term positions for the delivery-day and that means additional costs due to Power Exchanges fees, while, with PTRs, if a physical flow is done, there is no need to use spot markets, and those fees are saved.

Nordenergi advocates for a gradual development towards financial products all over Europe once price coupling is introduced, as all the physical capacity should be offered to the day-ahead market. CfD-products are well suited, though not liquid enough, for the Nordic market and it needs to be studied further whether FTRs could be used instead or together with CfDs. Nordenergi emphasizes that existing products shall not be replaced hasty when they better suite markets needs than FTRs.

Energy Norway thinks that in the long term the market should evolve away from PTRs towards FTRs, as all available capacity should be used in the market coupling process to increase its efficiency. Other financial products, such as the CfDs currently used in the Nordics, can be additional options, if they are functioning equally well to hedge area price differences. This needs to be assessed in an open manner.

ENTSO-E supports the evolution towards FTRs. However, this should be subject to certain preconditions, such as the implementation of market coupling and a proven interest of market participants as well as the resolution of firmness risk issues for TSOs. ENTSO-E recommends that in the FG the so called FTRs obligations are not put at the same level as FTRs options. CfDs issued by third parties – not related to

cross-border capacities - could coexist in parallel with Transmission Rights and be considered a valid alternative to Transmission Rights in those regions where financial markets are fully developed and have shown their efficiency.

5.3 Possible design of FTRs in the Nordic countries

The results of our interviews with different Nordic market players are presented in section 6. Some players are proposing an introduction of FTRs, some other have a positive attitude. However, most players struggled to see FTRs as a solution to their concerns for the Nordic market. It seems thus not so plausible that an introduction of FTRs in the Nordic market will be a result of a campaign by Nordic market players.

We believe therefore that any future demand on the Nordic TSOs to sell FTRs will probably be the result of a European process. The final draft FG on CACM stipulates in the provision 4.2 that FTRs or PTRs shall be provided unless appropriate cross-border financial hedging instruments are offered in liquid financial markets. This exception resembles the exception in point 2.8 in the Congestion Management Guidelines. Otherwise, point 2.5 in CMG stipulates that the access rights for long and medium-term allocations shall be firm transmission capacity rights.

The responses to the consultation on FG on CACM presented in the previous section show that several organisations and companies do not accept the exception in provision 4.2 in the final draft. EFET, EURELECTRIC, BDEW, Österreichs Energie, E.ON, RWE and EnBW argue all that FTRs or PTRs shall be implemented in a consistent way between all bidding zones in all parts of EU and that the exception in 4.2 shall therefore be deleted. Many of these organisations and companies argued also when the CMG were developed one decade ago. They were against a possibility to allocate all interconnection capacity through implicit auctioning and wanted explicit auctions instead also in the Nordic countries. However, the exception in CMG point 2.8 was not deleted and it allows that all interconnection capacity is allocated through implicit auctioning in regions where forward financial electricity markets are well developed and have shown their efficiency.

There is a possibility that the argumentation regarding 4.2 from these organisations and companies will succeed and that the exception in 4.2 in the final draft will be deleted in the next steps. Since many stress that it is desirable with an implementation in a consistent way in all parts of EU, the design of FTRs in the Nordic countries will probably in such a case be similar to the design of FTRs in other parts of EU.

It is of course not possible to make a precise forecast of a future design of FTRs in Europe. However, the responses to the consultation on the draft FG on CACM show that the present explicit auctions are the main reference for the discussion. The physical transmission rights in the explicit auctions shall be transformed into PTRs with UIOSI or FTRs. The change to PTRs with UIOSI is already done in some auctions.

The fact that the present explicit auction is the main reference means that the focus regarding FTRs is FTR options with hourly settlement. Such a 1 MW FTR option for e.g. one calendar year contains thus 8 760 hourly options regarding a specified transmission direction between two areas. The buyer receives every hour with congestion in the specified direction the price difference between the two areas. The buyer has no risk for extra payments in addition to the original option premium.

FTR options regarding the opposite direction are also normally valuable. A "normal" power flow between e.g. the Nordic area and the Continent is southwards in peak hours and northwards in off-peak hours. Congestions arise often in both directions. This means that FTR options can be very valuable even in situations when the two areas have the same average price.

FTR obligations mean on the other hand that the buyer receives or pays the average price difference between the two areas. If he e.g. buys a 1 MW FTR obligation for 2 EUR/MWh for a calendar year regarding a specified direction, he receives 35 040 (4*8760) EUR if the actual average price difference is 6 EUR/MWh. However, he has to pay 35 040 (4*8760) EUR if there are more congestions in the opposite direction and the actual average price difference is -2 EUR/MWh. An FTR obligation has thus the same principal function as a CfD-contract in the Nordic area. The main difference is that a Nordic CfD-contract is between one area price and the Nordic system price and that the FTR obligation is between two area prices.

Vattenfall argues in its response to the consultation on FG on CACM that the TSOs should auction FTRs as obligations and options, distribution decided in the auction based on market players' bids. However, no other response proposes FTR obligations. It can therefore be expected that a future demand on European TSOs to auction FTRs will not include FTR obligations, at least not in the first stages.

A general theme in the responses is that FTRs are financial contracts and shall as such be as firm as other financial contracts. A disturbance caused by "acts of God" causing lower actual transmission capacity shall thus not be considered a force majeure as it is for current PTRs. FTRs can thus in some situations result in much higher payments for the TSOs than the actual congestion rent.

The TSOs are offering year-ahead and month-ahead transmission rights in most European explicit auctions. The same timeframe would mean an obligation for the TSOs to sell FTR options for the next calendar year and the next calendar month. Some responses wish a longer time frame as FTR options for the two or three next years. Those who comment the issue wish that year contracts are cascaded into month contracts before the delivery year. Such cascading facilitates secondary trading and optimization of the portfolio.

It is unclear what percentage of the available transmission capacity that should be offered by the TSOs as FTR options for different timeframes. Some wish more capacity to be offered than in current explicit auctions. Others observe that strict firmness for FTR options gives a higher risk for the TSOs compared to current auctioning of PTRs. It can be noted that the current PTR auction between DK1 and Germany covers only 200 MW in the yearly auction and an extra 200 MW in the monthly auction of a total of 1500 MW towards Germany and 950 MW towards Denmark.

It is a wish in the responses that TSOs shall enable secondary trading in FTRs. However, the provision of the platform itself can preferably be transferred to a service provider.

6 Interviews with stakeholders

Interviews with stakeholders have been one important part of this study. We have interviewed nine market players in Sweden, Finland and Norway who represent different categories as industrial consumers, retailers, producers and traders. We have also interviewed three TSOs, two regulatory authorities and two exchanges. The following stakeholders have been interviewed:

- Akershus Energi
- Energimarknadsinspektionen
- E.ON Energy Trading
- Fingrid
- Fortum
- Göteborg Energi Din El
- Nasdaq OMX Commodities
- Nord Pool Spot
- Norske Skog
- NVE
- Oberoende elhandlare
- Statkraft
- Statnett
- Stora Enso
- Svenska Kraftnät
- Vattenfall

The interviews dealt with possible design of FTRs, consequences for risk management, interest in trading FTRs, consequences for the existent financial market, incentives for changed TSO behaviour and possible alternatives to FTRs.

The aim with the interviews has been to get qualitative input to our description and analysis. The aim has not been to get quantitative conclusions regarding percentages of market players with different views. Such quantitative conclusions would have required a much broader sample.

There is an important methodological challenge with such interviews, in particular in cases like the present, where it was not always clear to

the interviewees what FTRs are, how they could be traded, what the might offer the holder, etc. During the cause of the interviews, we quickly noted that many of the interviewees had a vague perception of FTRs before we started. An important part of many interviews was therefore to explain FTRs and discuss alternative possible designs of FTRs and their consequences. The answers shall therefore be interpreted with caution and rather be seen as preliminary positions than as final positions from many of the interviewees.

6.1 Consequences for risk management

Most of the interviewed market players could not see that FTRs in itself would improve their risk management.

The common reason for this view is that most market players in the Nordic region hedge the basic price risks by means of contracts with reference to the Nordic system price. The system price states the common Nordic price that would have been achieved with only one bid area to Nord Pool Spot for the whole Nordic area.

The system price can be interpreted as a virtual point, but it is by no means a physical point of delivery. Physical deliveries are settled against an area price. There is always a risk for a difference between the system price and the area price relevant to the market participant with a physical position. This area price risk is today to a large extent (see section 4) managed by CfD-contracts. An FTR gives a point-to-point hedge but that is not sufficient if the basic hedge is done in system price contracts. A point-to point hedge replaces one area price reference with another area price reference. One market player stated:

With a FTR, I can only replace one uncertainty by another.

No interviewed market player wanted to replace the basic hedging in system price contracts with basic hedging in area price contracts. Some Swedish players remembered earlier Swedish area price contracts, so called STOSEK contracts (Stockholm area in Swedish crowns), and wished no return to STOSEK contracts. The change to system price contracts has according to them resulted in a much more liquid market with many participants and small spreads.

However, some market players believed that FTRs could give better risk management.

E.ON and Vattenfall stated that FTRs would give a better hedge if production in one area is sold to a customer in another area. In the present system a combination of two CfDs is needed. This combination can be replaced by one FTR if FTRs are available between the two areas.

One player pointed out that natural changes in underlying physical positions because of changing production plans between plants in different areas and/or changing area definitions (the Norwegian practise) means from time to time a need to swap one area price hedge with another. Norske Skog has e.g. sold a 10 year contract referred to one area and purchased a 12 year contract referred to another area. FTRs could possibly have facilitated this swap.

6.2 Interest in trading FTRs

Most of the market players have their focus on risk management, not on trading. Many of these players have also trading mandates but the purpose of the trading is to improve the risk management ability not to perform a separate business. Some of these players believed it could be interesting to take part in FTR auctions. However, none of these players believed that FTR trading would be an important part of their trading activities.

Several of the market players with trading as a core activity were on the other hand interested in FTR trading as a new trading product. Especially companies with a more European trading focus were very interested.

Other market players were worried that FTR auctions would attract too few market participants, as they are likely to be too complicated and too odd for normal hedging desks. They see a risk for a transfer of a significant part of the congestion rent from TSOs and payers of the network tariff to trading organisations, especially the biggest trading organisations. Since the TSOs congestion rent is currently used to finance new transmission investments in the Nordic grid, they worry that the consequence will be either reduced investments or further increases in the network tariffs.

6.3 Consequences for the existing financial market

No interviewed market player wished a reduced liquidity in CfD-contracts. All wanted instead an increased liquidity in CfDs. The main reason is, as reported above in 6.1, that no interviewed market player wanted to replace basic hedging in system price contracts with basic hedging in area price contracts.

Some players believed that an introduction of FTRs would increase the liquidity in CfDs. One reason is that selling CfDs can be an interesting hedge for a buyer of FTRs. Buying FTRs can also be a risk-reducing strategy for a trader selling CfDs.

Some other players doubted that an introduction of FTRs would increase the liquidity in CfDs. They were worried that an introduction would split the existing liquidity in CfDs.

Another worry from some players were that a focus on FTRs could increase the focus on bilateral area price contracts and thus result in reduced liquidity in exchange-listed system price contracts. They noted that the current Nordic focus on system price contracts is a peculiarity in a European context. However, they saw a segmentation of the Nordic financial market into several area markets as an undesirable development.

Some players noted the possibility that an introduction of FTR options could give an increased interest in hourly contracts such as peak-load contracts and capacity options.

Many players and stakeholders saw it as essential that the present exception in the provision 4.2 of the final draft FG on CACM (see section 2.4) is not deleted in the next steps. With the exception for liquid financial markets with appropriate cross-border financial hedging instruments, it will always possible to introduce a demand on Nordic TSOs to supply FTRs if it is seen as advantageous for the market. It will also possible to withdraw such a requirement if it turns out to be disadvantageous for the market. However, without the exception in 4.2, such a withdrawal will not be possible.

6.4 Consequences for TSO behaviour

Nearly all interviewees believe that FTRs would change at least the short-term behaviour of TSOs regarding maintenance planning and breakdown management. They expect TSOs to perform measures in order to minimise the extent of transmission capacity reductions and to move planned maintenance to periods with less risk for severe consequences for the market. The result could be decreased reductions in available transmission capacity day-ahead and decreased costs for the market because of capacity reductions.

There are more opposite views among the interviewees regarding the consequences for investments in increased transmission capacity. Some believe that FTRs will increase the incentives for TSOs to invest. Others are worried that the incentives to invest can be reduced, especially if the demand on TSOs is that they shall auction FTRs as a certain percentage of the total transmission capacity.

Some interviewees were concerned that a demand on TSOs to offer FTRs and focus more on short term business economics can be at the expense of the long term obligations TSOs now have with respect to socio-economic development and maintenance of the transmission network. Although they want TSOs to be market oriented and focused on the needs and the demands of their customers, they do not necessarily want TSOs to be commercial profit-maximising companies. They believed that independent TSOs with the aim to promote efficient

functioning and competition in the market have been essential for the development of the Nordic market.

Another concern that was raised was that TSOs have several means to maintain a specified size of the transmission capacity, in particular with meshed networks and AC connections. It is not necessarily better for the society if the TSO, because of financial incentives, avoids transmission capacity reductions by allowing a reduced safety margin in the grid operation (e.g. temporary change from N-1 to N-1/2 or N-0).

All stakeholders accept a possibility for TSOs to adjust their positions because of failures etc. provided that such an adjustment is performed as a buy-back in a later auction and that it is transparently communicated before the auction. Some believe that it should also be possible for the TSOs to participate in a continuous secondary market for FTRs. However, most of the interviewees want that TSOs shall be forbidden to participate in a continuous secondary market for FTRs. They view TSOs as insiders regarding congestion risks.

Some note that all interconnections are not owned by the TSOs in the adjacent areas. Statkraft owns Baltic Cable between Sweden and Germany. The TSOs in the adjacent areas are Svenska Kraftnät and TenneT (DE). Their question is: Who shall be obliged to issue FTRs between Sweden and Germany? Statkraft (Baltic Cable AB) or Svenska Kraftnät/TenneT?

One stakeholder wondered if FTRs would be defined as financial instruments according to the directive on markets in financial instruments (MIFID). Shall the TSOs in that case present prospectus when they issue FTRs in an auction?

The consequences for TSOs if FTR buyers default were also discussed. It was mentioned that PJM had a combined exposure of nearly 100 MUSD against four FTR buyers that defaulted in 2007/2008.

7 Pros and cons with Nordic FTRs compared to the present system of CfDs – our assessment

A possible design of FTRs was discussed in section 5.3. The responses to the consultation on FG on CACM show that the European focus regarding FTRs is FTR options with hourly settlement. We therefore expect that a future requirement on European TSOs to auction FTRs will not include FTR obligations, at least not in the first stages. But we do expect that such a requirement to auction FTR options will at least include options for the next calendar year and the next calendar month. A longer time frame as FTR options for the two or three next years is also possible. We expect that year contracts will be cascaded into month contracts before the delivery year. We also expect that platforms for secondary trading in FTRs will be established.

7.1 FTRs as hedging products

FTRs will not directly improve the quality or relevance of current Nordic hedging strategies that to a large extent are based on system price derivatives. This is the case for the vast majority of Nordic fundamental players. The only feature FTRs provide to the current Nordic market is the ability to replace one area price risk with another area price risk, while the major challenge is to hedge the difference between the system price and any area price if the basic hedging is done in system price contracts. This area price risk is today to a large extent managed by CfD-contracts. As shown in section 4 above, the open interest in Nordic CfD-contracts for February 2011 was 10 747 MW in the end of January 2011 while the open interest in system price contracts was 14 188 MW. Most players want an increased liquidity in CfD-contracts but they are not prepared to change from the present combination of system price contracts and CfD-contracts to an alternative with basic hedging in area price contracts.

There are two types of exceptions from this general statement. The first one is that some players may need to swap one area price hedge with another. This is particularly the case for (large) industrial end users with electricity demand in multiple price zones. As consumption plans may change over time, it might become desirable to swap area price hedges. However, industrial end users' time horizon probably exceeds that of other market participants by several years. Large generators with assets in several zones could also have similar demand for swaps, but it is likely that their time horizon is shorter.

The second type of exceptions is related to vertically integrated companies with production and/or sales in multiple price zones. Some of such companies advocate a business model where the retail sales fill the role of a hedge for the generation (or vice versa). For such strategies, hedging via the system price is per definition not adequate unless in combination with pairs of CfDs. Thus completing the "natural" portfolio with FTRs appears as an attractive alternative with this business model. However, in the Nordic countries, most of the integrated companies have a business model where generation and retail are two separate businesses. The generation business sells its production in the Nordic wholesale market and the retail business buys its deliveries in the Nordic wholesale market.

We find it therefore hard to believe that FTRs will be popular hedging instruments in the Nordic region, even if the current CfD market is not improved. It appears that only a few vertically integrated companies employ a business model where generation is the hedge for retail sales (or vice versa). Also, we expect an important mismatch between the time horizons of the two most important market participants – generators and industrial end users.

There is also an extra dimension to be considered. Assume there is a liquid forward market in area A, and an illiquid market in area B. FTRs are introduced as a mean to create hedging opportunities for market participants in region B. Those considering contracts referred to area B (for hedging in that region) can now instead contract area A plus the FTR, effectively reducing the already low liquidity in area B. A forward contract in area A plus a FTR from A to B can be a perfect substitute for a contract in area B. However, it is more challenging to create good liquidity in both A, B and the FTRs between A and B, as compared to creating good liquidity in A and B. With liquid markets at each side, the FTR is unnecessary.

An interesting question in this context is if system price contracts will develop elsewhere in Europe. EPEX Spot and EEX launched in October 2010 a new index called ELIX. The index is calculated in the day-ahead auction organized by EPEX Spot and is equal to the uncongested price for the market areas Germany, Austria, Switzerland and France (i.e. a Continental equivalent to the Nordic system price).

7.2 FTRs as trading products

Traders appear as quite interested in FTRs. FTRs issued by TSOs required to do so will add a new trading product with volatility, with inelastic supply in the initial auctions, and hence enable new profit opportunities. If listed at an exchange and made "clearable" by a clearinghouse, FTRs will fit nicely with typical trading strategies of several market players.

However, it should be noted that only a minor part of the market participants have a trading motivation for their trading. The typical reason to trade is for most market participants to improve the quality and preciseness of their hedging activities. FTRs will not be an important part of trading strategies for such portfolios.

This observation contributes to the impression that the trading vision will partly be to capture a part of the congestion rent by accepting the volatile cash flow generated by FTRs, and partly serve as a mean to trade volatility. The chances that risk premiums will be relatively high are increased with the inelastic supply in the initial auctions and potentially few active market participants.

Some interviewees mentioned FTRs as instruments to reduce the potential for use of market power. Economic theory does not provide any support for such a view. FTRs, in combination with market coupling in the day-ahead markets, do not alter the relative size of any physical positions. Hence, FTRs cannot change opportunities to exploit market power in the physical market.[5]

On the other hand, FTRs can increase the payoff and reduce the risks for holders that have physical assets they would like to use as means to use market power. This depends on the overall contractual situation of the holders and several features of the market and FTR design, inter alia the auction mechanism, whether the FTRs are options or obligations, etc. Hence, there is in fact a risk that FTRs *increase* market power issues in the electricity market. It is therefore important that there is a coordinated market monitoring regarding the FTR market, other financial markets and the physical market.

A particular case is when a transmission asset is (partly) held by companies that also are generators or trading companies. A relevant example is the Baltic Cable, which is owned by a Statkraft-company. It can be profitable for such owners to increase the FTR prices in primary auctions (i.e. when transmission owners are issuing and auctioning FTRs for the first time). Depending on the detailed regulation of the transmission owner, the FTR market and the trading companies, this may fall short of rules against anti-competitive behaviour.

[5] This statement might not be true for other market designs than the one being considered for Europe in the context of this analysis: The FTRs we consider are supposed to be settled financially against the day-ahead prices in each reference point for the relevant FTR. The holders of the FTRs will not obtain any rights relevant for the day-ahead auctions itself. Hence, the fact that a large literature on FTRs in US electricity markets and elsewhere may show different conclusions as regards the impact on market power is not a contradiction with our statement – it merely reflects that quite a lot of the FTR literature is based on other market designs.

7.3 Consequences for liquidity in CfDs

All market participants want increased liquidity in the CfDs. It is a clear hope that introduction of a requirement for TSOs to issue FTRs will improve the liquidity in the CfD market. Whether that will happen or not is ultimately an empirical question. We note that for traders selling CfDs (i.e. without any assets that can serve as hedge for the seller), the ability to purchase FTRs in a primary or secondary market can reduce the risk they assume when selling CfDs. Thus there is at least an indirect reason that FTRs can improve CfD liquidity.

However, there is on the other hand a risk that introduction of FTRs will result in splitting of liquidity between CfDs and FTRs. The simple reason would eventually be that FTRs replace the role of CfDs in some hedging strategies. This might, at least hypothetically, in turn reduce the focus on combinations of system price and CfD contracts, and thereby decrease liquidity in CfDs. The worst consequence would be that the system price liquidity was jeopardised.

7.4 Consequences for TSOs

FTR requirements' impact on TSO behaviour depends to a large extent on the general regulation of the TSO. We identify the following possible effects of a requirement on TSOs to issue FTRs for a large part of the available transmission capacity between two areas:

1. After FTRs are sold, the major short-term risk for the issuing TSOs is if the capacities between two areas fall short of what is sold as FTRs. That would leave TSOs with an un-hedged cost. It will then be profitable to accept some costs and efforts to avoid such costs. Examples of such costs are improved planning of maintenance, and maintaining a larger stock of spare parts and components (e.g. transformers).
2. Another short-term risk for the TSO is that a buyer of FTRs defaults. This risk can be partly mitigated by appropriate credit requirements. It can also be mitigated if the FTR contracts are cleared with a clearinghouse.
3. TSOs also have a possibility to increase available transmission capacity for the day-ahead market without increasing their own costs, but instead increasing the risks for their customers. The TSO can by temporarily operating the grid at N-0 or N-1/2 avoid reductions in cross border capacity without direct expenses for the TSO. This might be an attractive alternative in cases of temporary needs to reduce transmission capacity.

4. A medium-term effect could be that the TSO become more conservative when deciding upon long-term available transmission capacity. Embedding an extra "reserve" when transmission capacity is defined and auction volumes are decided can reduce the risk that the short-term available capacities between two areas will fall short of what is sold as FTRs.
5. A long-term impact of a FTR requirement might be reduced profitability for investments in cross border capacity: TSOs generally have a good rating and a relatively low cost of capital. Their ability to carry risks is generally high, and the costs (of carrying risks) are moderate. But even if issuing FTRs relieve financial risks from a TSO, the profit of such hedging can quickly be negative. This will be the case if the buyers of FTRs require a risk premium to swap the volatile congestion rent with a fixed price. This possibility is supported by the experience from NorNed and the Danish-German border presented in chapter 3. If so, the financial impact on TSOs of issuing FTRs would be reduced project revenue. Reduced expected revenue will not increase investments for a company with good rating.

The changes in TSO behaviour from requirements to sell FTRs depend on the total "package" of regulation towards the TSOs. TSO regulation comprises strict performance measures for both short and long term as well as rules to determine revenue and/or prices (tariffs). TSOs can have a cost plus regulation or an incentive regulation or a combination. Thus the impact of a new component in the regulatory mix depends on the combination of other regulations. From the above comments, we can conclude that a requirement to issue FTRs may have a positive impact on availability, but may also introduce counterproductive incentives and behaviour:

- For the short term, TSOs with cost plus regulation can simply increase their tariffs to cover the economic exposure caused by a short position in FTRs. When this is the situation, FTRs will not improve the availability and short-term allocation of capacity. The only effect would be increased transmission tariffs.
- A temptation to operate the grid with reduced reliability could be mitigated by proper regulation – but the dilemma here is that with cost plus regulation, the FTRs will not incentivise the TSO at all, and with incentive regulation in place, the complexity of the regulation would increase if it were to include FTRs. Thus if the FTR requirements encourage TSOs to maximise availability of capacity, the same requirements will tempt the TSOs to mitigate temporary capacity problems by reducing the reliability of the network. This temptation cannot be removed by further regulation.

Issuing FTRs can be perceived as selling a uncertain and volatile cash flow for a fixed price. Buyers of FTRs purchase a cash flow that in principle can be described by its expected value, variance and other statistical properties. If buyers and sellers have similar information, all market participants will have the same opinion of what the expected value is, and what the risks are. If there is competition, the buyer with the lowest cost of carrying risk will submit the highest bid for purchasing the cash flow. However, profit-maximising traders will never be willing to pay the expected value for a probability distribution – their maximum willingness to pay will be below the expected value. Thus the FTR price will be systematically lower than the market estimate of the expected value. If the expected value could be observed, the difference between the FTR price and the expected value can be defined as the risk premium the TSO must pay because of the requirement to auction FTRs. In the end, this risk premium has to be paid by the network users via network tariffs.

7.5 Alternatives in the Nordic market to FTRs for improved risk management and increased available transmission capacity

The reason for Europe to focus on FTRs seems related to two main targets:

1. Improve hedging opportunities
2. Incentivise TSOs to maximise availability of transmission capacity

Regarding the cost of hedging area price risks, two ideas have been mentioned in the interviews and at the workshop:

1. A voluntary commitment by TSOs to offer CfDs via auctions. The purpose is to add extra supply of CfDs to the existing supply from the main producers. However, such a commitment will introduce new and unhedged risks to TSOs. It was mentioned that Svenska Kraftnät can as a first step contribute to liquidity in the four new Swedish bid areas by selling CfDs in the two southern deficit areas and buying CfDs in the two northern surplus areas. Such an approach for auctioning CfDs will not necessarily leave Svenska Kraftnät with a new system price risk. Nordic TSOs can in a similar way limit their combined risks if they offer CfDs in a coordinated way. A commitment to offer CfDs via auctions will probably be less risky for the TSOs than a requirement to offer FTR options via auctions.

2. Paying for a market maker service in the CfD market. As insufficient liquidity in the CfD market appears to be the main concern for most of the Nordic market participants, a more direct approach would be to examine whether a reasonable role for TSOs can be defined in this market. While it is far from natural to require TSOs to start acting as market makers, one could consider if TSOs could be required to support some kind of a market maker service.

Regarding the low available capacity, in particular on cross-border interconnections, some other alternatives have been suggested:

3. Requirement on minimum capacity between zones in the day-ahead market, countertrade if the required minimum capacity is higher than the real available capacity. The aim is to reduce the extent of area price differences and thereby reduce the area price risks. This option has been mentioned several times during the last years, and has so far received insufficient support to be accepted. One issue is the difficulties to organize a countertrade without efficiency losses. Another issue is the same that appear as a problem for FTRs as well: Unless the TSO is exposed to some sort of incentive regulation, countertrade is not a cost the TSO would have to care about. And this brings us to the next alternative:
4. Introduce incentive regulation of TSOs and include capacity and availability as quality parameters that are considered in the regulation. As FTRs and CfDs can have adverse incentives on TSO behaviour, an obvious option is to consider either direct regulation (fixed procedures and rules) or better-tailored and explicit incentives to maximise transmission capacity. While the former is mostly rejected in economic literature, there is ample experience with incentive regulation in general. The nearest example is how outages are accounted for in the regulation of Norwegian DSOs. It is not necessarily an optimal approach when it comes to cross-border capacity, but perhaps a somewhat similar approach could be more attractive than a requirement for Nordic TSOs to auction FTRs.

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