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# On Long-Term Transmission Rights in the Nordic Electricity Markets

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Academic Editor: Bin Chen
Received: 3 May 2016; Accepted: 23 February 2017; Published: 2 March 2017

**Abstract:** In vein with the new energy market rules drafted in the EU this paper presents and discusses two contract types for hedging the risks connected to long-term transmission rights, the financial transmission right (FTR) and the electricity price area differentials (EPAD) that are used in the Nordic electricity markets. The possibility to replicate the FTR contracts with a combination of EPAD contracts is presented and discussed. Based on historical evidence and empirical analysis of ten Nordic interconnectors and twenty bidding areas, we investigate the pricing accuracy of the replicated FTR contracts by quantifying ex-post forward risk premia. The results show that the majority of the studied FTR contain a negative risk premium, especially the monthly and the quarterly contracts. Reverse flow (unnatural) pricing was identified for two interconnectors. From a theoretical policy point of view the results imply that it may be possible to continue with the EPAD-based system by using EPAD Combos in the Nordic countries, even if FTR contracts would prevail elsewhere in the EU. In practice the pricing of bi-directional EPAD contracts is more complex and may not always be very efficient. The efficiency of the EPAD market structure should be discussed from various points of view before accepting their status quo as a replacement for FTRs in the Nordic electricity markets.

**Keywords:** Nordic electricity markets; financial transmission rights (FTR); electricity area price differentials (EPAD); risk management; hedging

**JEL:** G12; Q41; Q48; L94

## 1. Introduction

New electricity market rules, commonly called "network codes" are being drafted for the EU. The target is to create a framework that allows meeting the set 20-20-20 climate and energy targets and more recently building a basis for the "Energy Union". Transmission networks are the backbone of electricity markets that enable the sharing of resources between locations. For this reason many network codes relate to transmission networks. Network capacity is a scarce resource that often plays an important role in electricity price formation especially in cross-border electricity trade. Electricity buyers (and sellers) typically acquire transmission rights (capacity) in advance, or use financial securities to hedge their positions on the electricity markets. Different types of contracts on transmission rights, settled ahead the day-ahead and intra-day markets, are generally called "long-term" and the rights traded "long-term transmission rights" (LTRs).

The recently approved EU network code on forward capacity allocation (FCA) expects that a standard and securitized contract type called "financial transmission right" (FTR), will be used as the main vehicle on the markets for securing the distribution of long-term transmission capacity in Europe. This being the case one needs to observe that the Nordic electricity market has, since the year 2000, had its own standard securitized contract vehicle in use for the purpose of hedging bidding area price differences, the "electricity area price differential" (EPAD). There are differences between the Nordic and the Continental European electricity markets. For example, in the Nordic markets a "system price" is quoted and acts as a benchmark price for the markets (for overview, see [1]). There is no similar system price in the rest of the European electricity markets, although sometimes the German PHELIX spot is dubbed as "the system price" of the Western Central Europe [2,3].

EPAD contracts are used to build a hedge for a bidding area price in relation to the system price, while an FTR contract hedges the price difference directly between two adjacent bidding areas. This also means that in order to hedge the price difference between two adjacent bidding areas with EPADs, one must use a combination of two EPAD contracts (one long and one short). Such combinations of EPADs are commonly called "EPAD Combos" [4] and they are sold separately on the same marketplace as separate EPAD contracts. Two EPAD Combos are sold for each interconnector (connection between two bidding areas) to cover the hedge "both ways". The convention for choosing the direction of an FTR or EPAD Combo is based on the mean spot price difference between low-price and high-price areas, e.g., the producers in the low-price area with customers in the high-price areas buy a contract in the low-to-high direction, in order to limit the negative price risk exposure between the areas. Contract prices can be both negative and positive, which means that if the price is negative, buyers receive the clearing price, and when positive, the buyers pay the clearing price.

EPADs and EPAD Combos are securitized purely financial contracts traded in a securities exchange, without a direct link to the transmission capacity of the interconnectors and thus also without volume caps, while the FTR contracts are connected to the physical transmission routes and capacities. EPADs and EPAD Combos are put on market by the Nasdaq OMX, while the FTR contracts are (will be) typically auctioned by the transmission system operators (TSOs) in a single allocation platform at European level ([5], p. 3). This means that the market-mechanism of the hedging products in the Nordic market and the proposed FTR market is different.

Traditionally, including the Nordic markets, the TSOs receive bottleneck income that emerges due to price differences between bidding areas that are caused by congested interconnectors, see e.g., [6]. The EU regulates [7] the use of the revenues resulting from the congestion, which have to be used for grid development, or for lowering the transmission charges. With the FTR system, transmission system operator (TSO) as the auctioneer redistributes the bottleneck income to FTR holders as a compensation for the area price difference. This means that challenges, such as revenue adequacy [8], financial regulation, and/or firmness risk [9] appear, and must be faced by the TSOs.

Aside from the market participants' point of view, the bottleneck income issue connected to using EPAD Combos and FTR contracts is theoretically similar. The similarity is theoretical, because in practice the efficiency of the marketplaces, in which these contracts are traded, will also play a role. The issue of market efficiency is not trivial, as generally the expectation is that the markets for EPAD Combos (and EPADs) should be as efficient as that of FTRs. It is on the very premise of efficient enough "… liquid financial markets on both side(s) of an interconnector" [10] (p. 10) that the Agency for the Cooperation of Energy Regulators (ACER) has given the Nordic electricity markets an exemption from having to also implement FTR as the contract to be used.

Most of the European electricity markets have mainly experimented with physical transmission rights (PTR) and explicit auctions facilitated by allocation offices for cross border electricity transmission capacities—Capacity Allocation Service Company (CASC) and Central Allocation Office (CAO). More recently, the two allocation companies merged into what is called the Joint Allocation Office (JAO) and offer also financial transmission rights options in the Central West Europe (CWE) and Central East Europe (CEE) regions. In the Nordic setting, a pioneering exception can be found from the interface of the Nordic-Baltic markets and it is the Estonia-Latvian interconnector, where and for which FTR contracts are already being auctioned according to the FCA guidelines and harmonised allocation rules (EU HAR), see [11].

Against this background, this work sets out to explore the (future) compatibility and the substitutability of the FTR contracts with EPAD contracts for hedging of transmission risk in the Nordic markets. To shed light on this issue, this work presents the structure and characteristics of the standard FTR and the EPAD contracts, and of EPAD Combos that can be used to replicate the effect of FTR contracts. The structure and the characteristics of the three LTR vehicles are shortly comparatively analysed. To illustrate the real world context, we present a historical analysis of the ex-post forward risk premia included in the replicated monthly, quarterly, and yearly FTR contracts for ten selected interconnector cases during the years 2006–2013, including intra-national and international interconnectors. By quantifying the ex-post forward risk premia and studying their magnitude, persistency, and direction, we shed light on the accuracy of the market to price the replicated FTRs. The paper closes with conclusions and discussion on the policy implications of the findings. Before presenting the structure of the three LTR vehicles, we take a look at the previous literature on the subject matter.

*Literature Review*

There is a rather extensive literature available on electricity pricing that has a focus on the distortions on the wholesale [12–17] and retail [18,19] markets. Much less research attention has been devoted however towards studying the impacts of transmission [20] and distribution networks [21] on electricity markets. For example, Borenstein et al. [20] find that if a transmission line capacity is small in proportion to the size of the local markets, local generators may withhold production capacity and congest the import line. Such induced congestion increases the value of local generation. This finding is relevant to the Nordic bidding area price issues. Previous research also shows how allocation of physical, or financial, transmission rights may lead to exercise of market power [22–24]. Other studies consider detailed conditions, such as auction types, bidding rules, and allocation processes, under which transmission rights mitigate or increase market power [25,26].

The literature that studies the Nordic electricity markets and the products used for hedging within the Nordic markets is very limited. Currently available research that studies how well transmission risk hedging instruments function seems to consist of mainly industry reports [2,27–32]. The studies available vary in methodological approach (mostly interviews and desk research) and are rich in proposing different efficiency measures for power derivatives markets, such as liquidity (churn rate, turnover, transaction volumes), transaction costs (bid-ask spreads, entry costs), product transparency (open interest), market concentration (HHI, concentration ratios), and diversity of counterparties (market makers, entry-exit activity, traders diversity).

For example, a report by Redpoint Energy [28] evaluates long-term transmission rights solutions for the NorNed interconnector between the Netherlands and Kristiansand (Norway bidding area 1). The report finds lacking liquidity on both sides of the interconnector, lacking demand for cross-border hedging instrument, and general support for a more traditional contract for differences (CfD) instead of FTR. Another consulting report carried out for ACER [29] to evaluate the impacts of the FCA network code highlights the missing assessment of demand for FTRs, of the revenue adequacy and firmness risks for the TSOs, and of the questioning liquidity of FTRs and their impact on other energy derivatives. Hagman and Bjørndalen [27] compare the Nordic CfD (EPAD) to FTR and find that despite the needed improvement in EPAD liquidity, market participants see FTRs as a peripheral contract with negative impacts on liquidity in system futures. Houmøller [2] envisions that FTRs regularly auctioned by TSOs would feed liquidity to the EPAD Combo market, because FTRs would serve as a price reference, which is in the current system ambiguous or missing. Note that what this study calls EPAD Combo Houmøller [2] calls Cross-border Contract for Difference (CCfD).)

According to the Finnish TSO [33] a portion of market participants believe that the EPAD market functions relatively well, but others find the EPAD market illiquid and non-transparent, because of the lacking ask (sell) side on the Finnish EPAD market. Another study [31] questions the reliability of the daily closing price of EPAD contracts as a signal about the expected price difference between an area price and the system price. The study finds, the daily closing price mechanism omits the information included in the OTC trade that represents about 75% of the total EPAD trading volume.

Examples of academic research devoted to derivatives pricing of long-term transmission rights (LTRs) are limited. Among the rare exceptions are the pioneering studies by Kristiansen [8,34] who studies the Nordic seasonal and yearly CfD (EPAD) prices and finds them to be overpriced due to a stronger presence of risk-averse buyers (hedging pressures), who accepted to pay positive risk premia. Marckhoff and Wimschulte [35] also study the pricing of CfDs and find significant risk premia, which can be sufficiently explained by the existing models for power derivatives valuation [36,37]. Spodniak [38] tests simultaneous information processing on the spot and futures (EPAD) markets and studies long and short-run equilibria between the spot and the futures markets. The study shows that despite being in a long-run equilibrium EPAD futures and spot markets are not equally informationally efficient across different areas. The differences are explained by lacking EPAD liquidity on the one hand and by active speculation on the other. The next section of the paper introduces the structure of the three LTR vehicles in more detail.

## 2. Introducing and Comparing FTRs, EPADs, and EPAD Combos

The purpose of long-term transmission rights (LTR) is to provide market participants with hedging solutions against bidding area price difference risks that are created by interconnector congestion and day-ahead congestion pricing [39]. The structures of the three LTR vehicles relevant to this research, FTRs, EPADs, and EPAD Combos are discussed next.

### *2.1. FTR*

Financial transmission rights (FTRs) are financial contracts used for hedging the market price differences between two bidding areas (directly). Typically, FTRs are useful to those market participants, who are on the market either for buying from or selling to, a different bidding area than where they reside.

According to ENTSO-E [40], "the financial right gives the holder the right to collect revenue generated by the amount of MW he is holding". There are both obligation and option type FTRs: (i) FTR obligation means a right entitling its holder to receive, or obliging the holder to pay a financial remuneration, based on the day-ahead market results between the two bidding areas, during a specified time period, into a specific direction [41] (p. 9); (ii) FTR option holder, in turn, can choose not to execute the FTR contract, if the flow is in opposite direction. In other words, the hedging position depends on the chosen product type, the route, and the direction. The overall amount of FTRs is limited to the physical transmission capacity, but additionally the "netting" of FTR obligations is also possible (selling contracts bi-directionally in both directions). Because of counter-flows a higher volume than the actual transmission capacity may be issued, so FTR obligations provide netting, but FTR options do not.

In practice, FTRs are (will be) auctioned before the electricity delivery period and typically, TSOs (or single allocation platform) are those who auction the rights. In addition, bilateral trading of FTR can be possible on secondary markets. The holder of the FTR pays the auction clearing price and the possible revenue is equal to the hourly price difference between the bidding areas, during the (contracted) delivery period [40]. FTR can be auctioned, e.g., for period of a month, a quarter, or a year.

If FTRs are auctioned by TSOs, their bottleneck income originating from the area price differences is redistributed to the FTR holders. Hence, firmness and counterparty risks, as well as revenue adequacy problems can arise [8]. For instance, the firmness risk arises, when a TSO auctions capacity for an FTR, but the transmission capacity becomes unavailable afterwards, for instance due to technical faults. In such cases, a price difference between the two bidding areas will most likely "take place" and needs to be compensated to the FTR holder, but because of the unavailable transmission capacity the TSO is unable to collect any congestion rent. Such situations may cause problems. For discussion on firmness risk on the Nordic electricity markets from TSO's perspective, see [26]. Table 1 presents a summary of the characteristics of FTR contracts.

**Table 1.** Main characteristics of FTRs, EPADs, and EPAD Combos.

| Attributes | Long-Term Transmission Rights (LTR) | | |
|---|---|---|---|
| | **Financial Transmission Rights (FTRs)** | **Electricity Price Area Differentials (EPADs)** | **Combinations Of Electricity Price Area Differentials (EPAD Combos)** |
| Underlying | Hourly spot price difference between two bidding area prices | Hourly spot price difference between bidding area price and the system price | Hourly spot price difference between two bidding area prices |
| Specification | Position dependent on the chosen route and direction | Requirement for the system price calculation | Combination of two EPAD contracts; requirement for the system price calculation |
| Hedging | Provides a complete hedge, if market participants have a physical position in both markets. Option or obligation type | Provides a complete single area hedge, if market participants have a financial position for system price and physical position in the market. Obligation type | Provides a complete hedge, if market participants have a financial position for system price and physical positions in both markets. Obligation type. |
| Volume limits | Financial contract limited by the volume of physical transmission capacity, with the possible netting (selling higher volume due to counterflows) | Independent financial contract unrestricted by transmission capacity volumes | Independent financial contract unrestricted by transmission capacity volumes |
| Auctioneer/ marketplace | Auctioned by transmission system operator (TSO) or "allocating company" | Sold and cleared by an exchange | Sold and cleared by an exchange |
| Risks | Firmness and counterparty risks, revenue adequacy, impacts on bottleneck income | Counterparty risks borne by the exchange; firmness ensured (OTC and bilateral trade risks separately) | Counterparty risks borne by the exchange; firmness ensured (OTC and bilateral trade risks separately) |
| Trading | Liquidity for longer timeframes supported by additional contracts, e.g., Auction Revenue Rights (ARR), liquidity dependent on secondary market place efficiency | Electronic trading system (ETS), OTC and bilateral trading; liquidity dependent on market place efficiency | Electronic trading system (ETS), OTC and bilateral trading; liquidity dependent on market place efficiency |

### 2.2. EPAD

Electricity Price Area Differentials (EPADs) are purely financial contracts that can be used for hedging against the difference between a system and a bidding area price on the Nordic electricity markets. The EPAD contracts are futures contracts and hence are of the "obligation" type, option type EPAD contracts are not available. To operate the EPAD markets, a system price calculation is performed for the day-ahead electricity markets. The system price is a calculated price that omits considering any and all grid congestions between bidding areas. The area prices, in turn, take into account the grid congestions between areas. While the system price is a respectable reference, all bidding areas of the Nordic market shared a common electricity price only for 3% of all hours of the year 2014 [6]. Out of the total cleared volumes of all the Nordic power derivatives the share of EPAD cleared volumes range between 6.5% and 9% [42].

The volume of EPADs traded is not limited by the physical transmission capacity of the Nordic network nor does a "specific route" or interconnection play any role—in this sense EPADs are "independent" financial products. EPAD prices can be positive or negative, depending on the market participants' expectations of the price difference during the delivery period. The last trading day price of an EPAD sets the reference price (expiration day fix), against which the subsequent hourly price differences between the system and the bidding area prices are settled during the delivery period (spot reference settlement). For detailed contract specifications and trading procedures, see [43]. Nasdaq OMX currently operates the marketplace for EPAD contracts with monthly, quarterly, and yearly maturities, for eleven bidding areas in the Nordic electricity markets.

Counterparty risk in the EPAD markets is borne (guaranteed) by the exchange and the firmness of the exchange traded contracts is thereby ensured. EPADs can also be traded OTC or bilaterally. The efficiency of the EPAD marketplace has been recently studied [31,38,44] and the findings indicate that there may be a reason to believe that EPAD markets are not always efficient. See Table 1 for a summary of the characteristics of EPADs.

It is important to observe that in order to fully hedge a position on the Nordic electricity market, participants with physical positions need to bundle two separate power derivatives contracts—a contract that hedges the system price and another that hedges the system-area price difference (EPAD).

### 2.3. EPAD Combo

EPAD Combo is a hybrid of two EPAD contracts that contains two EPADs with the same maturity for two bidding areas, one that hedges the first bidding area price vis-a-vis the system price and another that hedges the second bidding area price vis-a-vis the system price, thus effectively hedging the difference between the first and the second bidding area prices.

Currently there are no ready-made EPAD Combo securities available on the Nordic electricity markets, but Combos can be constructed by the market participants or "bought as ready Combos" from financial operators. The two EPADs that make the combo are "separate" EPAD contracts and therefore their characteristics are the same as those of single EPAD contracts (discussed above), i.e., EPAD Combos are obligation type contracts (futures) as the underlying EPADs are of the obligation type. EPAD Combos are useful to those market participants, who are on the market either for buying from, or for selling to, a different bidding area, than where they reside. This is the same "raison d´être" that is underlying the FTR contracts, as explained above. See Table 1 for a summary of the characteristics of EPAD Combos.

In the following sub-section we further compare the structure of the three LTR vehicles, go through the differences in the risks involved, and discuss some details of the playing-field in which the replication takes place.

### 2.4. Short Structural Comparison of FTR, EPAD, and EPAD Combo

All three LTR vehicles fulfil the purpose of providing market participants with hedging solutions against congestion costs and the day-ahead congestion pricing. Structurally, they differ in terms of the underlying commodity being hedged: EPADs provide a hedge against a single area price risk by limiting the price difference between an area price and the system price, while FTR hedge the price difference between two area prices directly, and EPAD Combos enable hedging price differences between two area prices "via" the system price. The structure of these LTR vehicles in terms of their underlying is illustrated in Figure 1.

In addition to the differences in the underlying, EPAD, FTR, and EPAD Combo differ with respect to the volume of the amount of tradable securities and in the organization of the auction/initial markets of the securities. As discussed above the volume of the EPAD and EPAD Combo securities is unlimited and not in relation to the actual physical transmission capacity on the "ground", while FTR contracts (obligations) are based on the actual physical transmission capacity with the additional possibility of netting. This may mean that less speculation can be expected to occur in the FTR trade than with EPAD and EPAD Combo trade. What this may perhaps also mean is that a virtual, fully independent of the physical transmission capacity FTR-based derivative may appear, if there is the basis for a strong enough speculative trade on these contracts. The EPAD securities are "emitted", or put to sale, by market participants with the proper "trading licenses" that is, for example, power producers and other strong market participants may offer EPAD contracts for sale, while they guarantee according to the rules of the exchange to honour their obligations with regards to the emitted securities. The pricing of the initial issue of these securities depends on the participants putting them up for sale. The FTR are auctioned by the TSOs in a single allocation platform at European level ([5], p. 3) and the auction determines the initial price of the contracts. Both securities have secondary markets where the price is formed according to the supply and the demand.

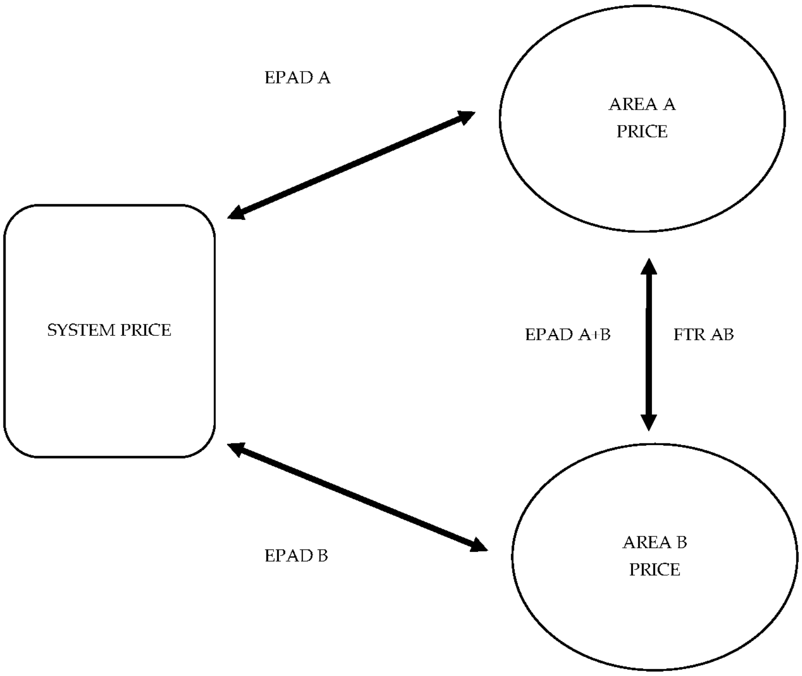


**Figure 1.** Structural differences with regards to the underlying of the three vehicles.

An important difference between the vehicles is related to risks. With the EPADs and EPAD Combos the risks involved are the typical counterparty risks that are involved in securities exchange trade. With regards to the FTRs the risk profile is different, because the FTR contracts are connected to the physical amount of available transmission capacity. What is called the "firmness risk", is a risk that stems from the possibility that the size of the actual transmission capacity auctioned becomes smaller (line faults, repairs, etc.) before the actual delivery. Capacity curtailments have direct financial consequences, because they change the energy arbitrage opportunity between two bidding areas. In this respect, the main difference between EPADs, EPAD Combos, and FTRs is relevant for the actors that bear the firmness risk associated with the physical characteristics of the assets underpinning the allocated capacity [45] that is, the possible costs from these risks materializing will have to be compensated to the FTR holders typically by the TSOs.

TSOs are able to collect bottleneck income that they most likely can use to cover these risks according to the EC regulations [7]. Otherwise the bottleneck income is used to guarantee the actual availability of the allocated capacity, for maintaining or increasing interconnection capacities, and for reducing network tariffs. The costs materializing from the firmness risk can also be shared between the TSOs and the capacity users (FTR holders) by setting a cap on the FTR contract payments or by including a "risk premium" on the initial FTR auction limit prices [45].

It is also important to note that an FTR contract price is directly dependent on the price difference between the two bidding areas in question; however an EPAD Combo price is also dependent on the joint relationship between the two areas prices vis-a-vis the system price. This means that there are more possible "states" that can occur, when an FTR is constructed with two EPAD contracts, than are possible with a pure FTR. Dramatic changes in the relationship between the area prices and the system price may occur during the maturity of EPAD contracts, which may cause difficulty in being able to judge the best combination of EPAD contracts (from the four possible contracts between two areas and the system price) to be is used to replicate an FTR. Put simply, it may be more difficult to forecast two rather than one price difference.

Notwithstanding the observed differences between the construct of the three LTR vehicles, what remains is that the obligation type (future) FTR contract and EPAD Combo are theoretically equivalent in terms of the protection they offer. This theoretical equivalence is however a simplification of reality since it omits firmness, counterparty, and revenue adequacy risks, among others. Also the reliance on exchange-quoted EPAD closing prices represents a risk because previous research has shown that the Nordic EPAD markets may not be efficient in terms of contract pricing [31,38,44]. Nonetheless, based on the market data it makes sense to explore how replicating FTRs with EPAD combos works out in reality.

## 3. Hedging with FTRs in the Nordic Electricity Markets: An Empirical Analysis

In this section we replicate the hedging of transmission risk in the Nordic electricity markets by using EPAD Combos as a proxy for FTRs. We perform an empirical analysis on historical market data (2006–2013) and estimate the forward risk premia in FTRs used for hedging locational price risk between twenty interconnected bidding areas on seven international and three intra-national Nordic grid interconnectors. By using established risk premia methodology, we are able to shed light on the accuracy of the current market to price the replicated FTRs. This section first presents the methodology behind risk premium calculations, including theoretical grounding and practical interpretation. Then, the data behind the empirical analysis is presented, including detailed background of the selected interconnectors. The section ends with results and discussion.

### *3.1. Risk Premium Methodology*

One approach to investigate pricing accuracy of electricity futures contracts, in this case replicated FTRs, is to calculate risk premia, which are systematic differences between the trading prices of electricity derivative contract ($F_{t,T}$) and the contract's expected (ex-ante) spot price when it is delivered ($E_t(S_{T,T})$). We call this systematic difference a forward risk premium, in line with [35,36,46,47]. Forward risk premia can be understood as mark-ups or compensations in the derivatives contracts charged either by suppliers or consumers for bearing the price risk for the underlying commodity (electricity) ([47], p. 1887). Initially [48–50], research on risk premia has argued that the difference between the current futures price and the expected future spot price is negative, because producers are under greater hedging pressures, which puts a downward pressure on the current futures prices as compared to the expected spot prices. Nonetheless, the more recent studies [30,37,51,52] describe both, positive and negative relationships, indicating that consumers may also be under a greater hedging pressure, which puts an upward pressure on the current futures prices as compared to the expected spot prices.

In the forward and futures pricing literature (equity, foreign exchange, and fixed income derivatives) it is a common practice to calculate the ex-ante premium in the forward price as an ex-post differential between the futures prices and the realized delivery date spot prices [53]. Longstaff and Wang [47] suggested this ex-post approach to risk premia in electricity forward prices by using $S_{T,T}$ as a proxy for $E_t(S_{T,T})$), and Marckhoff and Wimschulte [35] applied this proxy to calculate the ex-post risk premium for EPADs. In our study, we too embrace the ex-post approach to risk premia which we calculate for replicated FTRs.

As a basis for our calculations we assume that the EPAD contracts used in the FTR replication are acquired on the last contract trading day at the last trading day closing price (expiration day fix ([43], p. 9)). This also implies that we omit mark-to-market during the trading period, which is called the expiry market settlement [43]. The last trading day closing price can arguably be said to contain the most information about the coming future for which the contract is made and therefore it is the markets' best estimate (including risks) on the average area price difference between the two areas during the delivery of the contract.

From the above stated, the ex-ante risk premium is expressed by Equation (1) and the ex-post risk premium is expressed by Equation (2):

$$\pi_{t,T}^{FTR} = FTR_{t,T} - E_t(FTR_{T,T}) \quad (1)$$

$$\pi_{t,T}^{FTR} = FTR_{t,T} - \frac{1}{n}\sum_{h=T_1}^{T_2}(P_h^{Area\ A} - P_h^{Area\ B}) \quad (2)$$

where: $\pi_{t,T}^{FTR}$ is the average FTR risk premium; $FTR_{\ t,T}$ is the last trading day ($t$) closing price of FTR for the corresponding yearly, quarterly or monthly contract in a given direction (replicated $FTR\ A\ to\ B = F_{t,T}^{Area\ A} - F_{t,T}^{Area\ B}$) for the delivery in time $T$; $E_t(FTR_{T,T})$ is the expected FTR price at time $t$ for the delivery period in time $T,T$; $T_1$ and $T_2$ are equal to the start and end of the FTR's delivery period, respectively; $P_h^{Area\ A}$ and $P_h^{Area\ B}$ are hourly (h) area spot prices for area A and B during the FTR contract delivery period; and $n$ is number of hours between the start ($T_1$) and end ($T_2$) of the FTR contract delivery period. Note that in markets with nodal pricing the FTR direction is often specified by using the terminology infection (POI) and point of withdrawal (POW).

FTR risk premium at time t for delivery at time $T$ is equal to the FTR price at time t for delivery at time $T$ minus the average realized difference between the interconnected area prices during the delivery period between times $T_1$ and $T_2$. The risk premium for each delivery period (year, quarter, and month) and area pairs is computed individually. Two ex-post approaches to risk premia can be applied: (1) Risk premium as difference between average futures prices (FTR) and the average spot price difference between the interconnected bidding areas during the delivery period [34,54]; and (2) Risk premium calculated on a daily basis instead of averaging over the entire delivery period [35]. For the purpose of this study we have selected to study the average differences over the delivery period, according to the first approach.

The underlying question behind risk premia is whether they denote a natural behaviour of risk-averse market participants willing to pay (accept) a risk premium (discount) for transferring the risk of unfavourable spot price movements [35], or whether they are a sign of market inefficiency, such as arbitrage [55]. From the current data and empirical analysis we cannot disentangle the two directly, but we can study the magnitudes, persistency, and direction of risk premia, which then shed light on the accuracy of the market to price the replicated FTRs. Put differently, by studying risk premia we may assess, whether the theoretical FTRs are unbiased predictors of the future price differences between the interconnected areas.

### *3.2. Data*

Our sample covers an eight-year period from 2006 to 2013 and includes a number of contracts for a selection of interconnectors and for the three contract durations. The maximum number of yearly, quarterly, and monthly contracts for each interconnector is 8, 32, and 96 respectively. The reason behind having fewer contracts (smaller sample size) for some of the selected interconnectors are changes in the number of bidding zones during the studied time period (e.g., bidding area "Sweden" was split into four separate bidding zones in November 2011) or delayed introduction of EPADs (e.g., Estonia joined the Nordic market in April 2010, but only introduced the first EPADs by the end of 2012). In total, our sample includes 49 yearly, 172 quarterly, and 487 monthly replicated FTRs. The data used to run the analyses consists of two datasets that represent the Nordic futures (EPAD) markets and spot markets. The futures market dataset was obtained from Nasdaq OMX Commodities and includes aggregated daily market outcomes (including, for instance, the bid-ask spreads and the volume traded) from EPAD trading. The main focus of interest here is the daily closing price (daily fix) of each contract and the last trading day closing price (expiration day fix). The spot market dataset was obtained from the Nord Pool Spot and consists of hourly system and area prices, based on the outcome of the day-ahead market auction (Elspot). The hourly spot price difference between area and system price is the underlying "asset" for EPADs during their delivery period. In the case of EPAD Combos used here for the replication of FTRs, the underlying asset is the hourly spot price difference between two interconnected bidding area prices. This is because the system price disappears from the underlying spot price calculation, i.e., (area price A − system price) − (area price B − system price) => area price A − area price B => underlying asset for FTR.

Ten interconnectors were chosen for the empirical analysis based on historical, technical and economic reasoning. Most of the interconnectors are important parts of security of supply in each country, have large transmission capacity, and due to congestion represent important locational price risk for trades across areas. See the summary of selected cases in Table 2 and statistical summary of price distributions in Appendix A.

**Table 2.** Background of the selected interconnectors.

| Case | Bidding Areas A > B | Capacity (MW) | % Price Difference [1] | Background of the Interconnector |
|---|---|---|---|---|
| Sweden-Finland | SE/SE3 > FI | 1200 | 9% | In 2012, Russian electricity exports to Finland were significantly reduced due to market design changes in Russia. Finland substituted the capacity with increased imports from Sweden that strained the limited SE > FI interconnectors [56]. |
| | SE1 > FI | 1500 | 27% | |
| Sweden-internal | SE2 > SE3 | 7300 | 4% | Due to systematic internal congestions, Sweden was to split from a single bidding area into four areas in November 2011. Most of the low-cost hydro-production is located in Northern Sweden (areas SE1 and SE2), but consumption is mostly in the South (SE3 and SE4), see [57]. |
| | SE3 > SE4 | 5300 | 10% | |
| Norway-Sweden | NO1 > SE/SE3 | 2145 | 35% | The so-called "Hasle cross-section" from Norway to Sweden is important not only for Central-Sweden (SE3) to import power from the Southern Norway (NO1), but also for the whole of the Nordic market. However, the long-planned grid investment (Westlink) to this region was cancelled in 2013 by the Norwegian and the Swedish TSOs, see [58]. |
| Denmark internal | DK1 > DK2 | 600 | 28% | Areas DK1 and DK2 were initially not synchronized, and the first major power link (Great Belt) was built only in 2010. The DK1> DK2 interconnector has the most volatile price differences in the Nordic markets with frequent price spikes (see Appendix A). Area DK2 houses most of the Danish wind power capacity, which contributes to the area price spikes. Historically, the different production mix of Denmark (coal, wind) and Sweden (nuclear, hydro) have increased pressures on the interconnectors between the two countries [57]. |
| Sweden-Denmark | SE */SE3 > DK1 | 680 | 23% | |
| | SE */SE4 > DK2 | 1300 | 19% | |
| Norway-Finland | NO4 > FI | 100 | 26% | Norway is a lower production cost hydro-dominated market than the more thermal-energy-based Finnish market. The interconnector's small capacity causes it to only have a limited impact on Finnish prices. |
| Finland-Estonia | FI > EE | 1000 | 21% | The main purpose of the Finland-Estonia interconnector is to improve the security of supply and competition in both markets. Transmission risk management is relevant for both sides of the Finnish-Estonian interconnector. |

[1] "% Price Difference" refers to the number of hours area B has had a higher price than area A (in the A to B direction), out of total hours during 1 January 2006–31 December 2013 (see Appendix A for details); * SE represents Sweden as a single bidding area until the end of October 2011, after which it was split into four separate bidding zones SE1 Luleå, SE2 Sundsvall, SE3 Stockholm, and SE4 Malmö; Abbreviations for the other bidding zones used in the analysis are: Finland (FI), Estonia (EE), Århus (DK1), Copenhagen (DK2), Oslo (NO1), and Tromsø (NO4).

### 3.3. Results and Discussion

Before presenting the final results, we illustrate the interpretation of outcomes under explicit assumptions in a more general context. Table 3 presents eight scenarios leading to a specific sign of risk premia (positive + or negative −) depending on the sign of the underlying spot (S) and futures (F) prices (positive + or negative −) as well as their absolute sizes (S > F or S < F). We may split the table into two parts according to the market's ability to price the futures (FTRs) correctly (naturally), or incorrectly (unnaturally).

Scenarios 1, 2, 7, and 8 represent a category, where the FTRs are, under our definitions, correctly priced with respect to the underlying spot price outcome, i.e., both price sets have equal sign which means that a buyer receives the FTR clearing price and pays the negative spot price outcome, which fixes his/her risk exposure. This is, if the market participants priced a futures contract negatively, the spot price outcome turned out to be also negative during the delivery period (scenarios 7 and 8). Assuming both FTR and spot positions, this may be a typical case for hedgers with production in lower price area and consumption (customers) in higher price area looking for a contract against the negative exposure to locational price risk. By the same token, scenarios 1 and 2 represent correctly priced futures, where positively priced FTRs match with the market participants' expectations of positive price spread between the underlying bidding areas. This means that a buyer pays the positive FTR clearing price and receives the positive spot position, which again fixes his/her price spread exposure between the interconnected areas. In all the "correctly priced" scenarios, the positive and negative risk premia depend on the risk aversion, hedging needs, and market shares of the market participants, who are willing to pay (accept) a risk premium (discount) pushing prices above (+), or below (−) the risk-neutral expected spread.

Scenarios 3, 4, 5 and 6 represent a category of unnaturally (counter flow) priced FTRs, which do not offer any hedging value for the market participants. In scenarios 3 and 4 buyers expect and pay the positive FTR price (area price A > area price B), but the underlying spot (S) outcome turns out negative during the delivery period (A < B). This makes the buyers of positive FTRs pay the positive clearing price and additionally face the negative locational spot price spreads in the spot market. In scenarios 5 and 6 FTR buyers expect and receive the negative FTR price (area price A < area price B), but the underlying spot (S) outcome turns out positive during the delivery period (A > B). Assuming physical spot positions, this outcome means that sellers of negative FTRs paid the clearing price for the expected negative spot price outcome that they did not collect in the spot. Vice versa, the buyers of the negative FTR received the clearing price and additionally the positive spot difference. Briefly, in scenario 3–4 (5–6) FTR buyers (sellers) would be better off by simply trading spot across borders, than with the additional FTR derivative.

**Table 3.** Risk premia outcomes under given price assumptions.

| Scenario | Spot (S) | Futures (F) | Assumption (ABS *) | Risk Premium (F-S) |
|---|---|---|---|---|
| 1 | + | + | S > F | − |
| 2 | + | + | S < F | + |
| 3 | − | + | S > F | + |
| 4 | − | + | S < F | + |
| 5 | + | − | S > F | − |
| 6 | + | − | S < F | − |
| 7 | − | − | S > F | + |
| 8 | − | − | S < F | − |

Note: Sign of risk premium (positive + or negative −) depends on the sign of the underlying spot (S) and futures (F) prices (positive + or negative −) as well as their absolute (ABS *) sizes (|S|>|F| or |S| < |F|).

For the sake of brevity, we summarize the results for each interconnector and contract type (yearly, quarterly, and monthly) for the entire eight-year period studied (full and detailed results for each EPAD, FTR, bidding area, and time period are available upon request from the corresponding author). Table 4 presents the average spot price, futures price, and risk premium for the theoretical FTRs during 2006–2013. The spot price refers to the average hourly spot price difference (EUR/MWh) between the interconnected bidding areas during the delivery of individual FTR contract. The futures price refers to the average last trading day closing price (EUR/MWh) of FTR for the corresponding yearly, quarterly, and monthly contract in a given direction. Risk premium is the average difference between the futures price ($FTR_{t,T}$) and the ex-post delivery date spot price difference between the underlying bidding areas (see Equation (2)).

**Table 4.** Average spot price, futures price, and risk premium for the theoretical FTRs during 2006–2013.

| Interconnectors | Variables | YEARLY FTR | | QUARTERLY FTR | | MONTHLY FTR | |
|---|---|---|---|---|---|---|---|
| | | Avg. | St. Dev. | Avg. | St. Dev. | Avg. | St. Dev. |
| SE */SE3 > FI | Spot price | −0.94 | 1.57 | −0.97 | 2.37 | −0.92 | 2.47 |
| | Futures price | −0.90 | 1.26 | −1.17 | 2.13 | −1.12 | 2.73 |
| | Risk premium | 0.04 | 1.56 | −0.24 | 1.72 | −0.20 | 2.00 |
| | Sample size | 8 | 8 | 32 | 32 | 96 | 96 |
| SE1 > FI | Spot price | −3.44 | 2.08 | −3.43 | 2.16 | −3.20 | 3.29 |
| | Futures price | −4.59 | 0.93 | −5.71 | 2.76 | −5.85 | 4.35 |
| | Risk premium | −1.15 | 3.02 | −2.28 | 2.54 | −2.66 | 3.04 |
| | Sample size | 2 | 2 | 8 | 8 | 26 | 26 |
| SE2 > SE3 | Spot price | −0.40 | 0.20 | −0.40 | 0.36 | −0.45 | 0.64 |
| | Futures price | −1.92 | 0.83 | −1.69 | 1.10 | −1.84 | 1.78 |
| | Risk premium | −1.52 | 0.63 | −1.29 | 0.84 | −1.39 | 1.32 |
| | Sample size | 2 | 2 | 8 | 8 | 26 | 26 |
| SE3 > SE4 | Spot price | −1.18 | 0.99 | −1.18 | 1.43 | −1.39 | 2.17 |
| | Futures price | −4.76 | 2.53 | −2.63 | 2.12 | −2.21 | 2.39 |
| | Risk premium | −3.58 | 1.54 | −1.45 | 1.96 | −0.82 | 2.36 |
| | Sample size | 2 | 2 | 8 | 8 | 26 | 26 |
| NO1 > SE */SE3 | Spot price | −3.39 | 3.83 | −3.39 | 5.98 | −3.42 | 6.65 |
| | Futures price | −2.34 | 1.57 | −3.52 | 4.28 | −3.67 | 5.32 |
| | Risk premium | 1.05 | 4.28 | −0.14 | 4.85 | −0.38 | 4.11 |
| | Sample size | 8 | 8 | 32 | 32 | 96 | 96 |
| DK1 > DK2 | Spot price | −2.85 | 3.43 | −2.85 | 5.90 | −2.82 | 7.87 |
| | Futures price | −2.64 | 2.83 | −2.97 | 4.46 | −2.93 | 7.18 |
| | Risk premium | 0.21 | 4.25 | −0.12 | 6.62 | −0.11 | 6.94 |
| | Sample size | 8 | 8 | 32 | 32 | 78 | 78 |
| SE */SE3 > DK1 | Spot price | 0.50 | 4.93 | 0.51 | 7.66 | 0.16 | 9.63 |
| | Futures price | −2.68 | 6.22 | −1.23 | 8.05 | −0.43 | 10.41 |
| | Risk premium | −3.18 | 7.73 | −1.74 | 7.60 | −0.59 | 7.97 |
| | Sample size | 8 | 8 | 32 | 32 | 78 | 78 |
| SE4 > DK2 | Spot price | −1.52 | 2.60 | −1.51 | 3.54 | −1.42 | 3.68 |
| | Futures price | −0.65 | 0.07 | −1.39 | 2.04 | −1.81 | 3.66 |
| | Risk premium | 0.87 | 2.67 | 0.12 | 3.25 | −0.40 | 2.17 |
| | Sample size | 2 | 2 | 8 | 8 | 26 | 26 |
| NO4 > FI | Spot price | −4.01 | 2.06 | −4.00 | 2.73 | −3.79 | 3.85 |
| | Futures price | −5.13 | 1.17 | −5.65 | 2.81 | −6.47 | 4.62 |
| | Risk premium | −1.11 | 3.23 | −1.65 | 2.37 | −2.68 | 2.69 |
| | Sample size | 8 | 8 | 8 | 8 | 25 | 25 |
| FI > EE | Spot price | −1.99 | – | −1.98 | 1.88 | −2.01 | 4.91 |
| | Futures price | 1.05 | – | 0.82 | 0.88 | 0.38 | 2.63 |
| | Risk premium | 3.04 | – | 2.80 | 1.44 | 2.39 | 5.66 |
| | Sample size | 1 | 1 | 4 | 4 | 10 | 10 |

Note: Futures price represents the average last trading day closing price (EUR/MWh) of the FTR for the corresponding yearly, quarterly, and monthly contracts in a given direction; Spot price represents the average hourly spot price difference between the two underlying bidding areas during the delivery period (EUR/MWh); Risk premium represents the average risk premium calculated as the difference between Futures price and Spot price (see Equation (2)); Sample size represents the number of contracts in the sample for each interconnector; Because of the varying sample size across contract types and interconnectors, we do not report the significance values for the risk premia. However, for instance the mean risk premia for all monthly contracts were all significantly different from zero according to a one-sample t-test at 5% significance level (full results available upon request); Total sample includes 49 yearly, 172 quarterly, and 487 monthly FTRs; St. Dev refers to standard deviation; Avg. refers to arithmetic mean. * SE represents Sweden as a single bidding area until the end of October 2011, after which it was split into four separate bidding zones (SE1-SE4).

From the aggregated results in Table 4, it is visible that the interconnector pairs selected for the analysis are directed from low to high area price, as indicated by the negative average spot prices. One exception is the interconnector SE/SE3 > DK1, which exhibited a positive average spot price spread, i.e., DK1 was the lower area price on average. Using the terminology of "correctly" priced FTRs mentioned above we see that the replicated FTR contracts would give a correct (natural) price signal with respect to the direction of the price risk for eight out of ten interconnectors, as indicated by the same sign of the futures and spot prices. The two exceptions were SE/SE3 > DK1 and FI > EE interconnectors, where the market has unnaturally priced all the replicated FTRs (monthly, quarterly, and yearly) and gave the opposite price signal (reverse flow) for the futures and the spot outcomes.

Again, using the terminology from the illustrative scenarios linked to Table 3, buying the transmission hedge on the SE/SE3 > DK1 interconnector in the given direction from Sweden/Stockholm (SE/SE3) to Århus (DK1) leads to a large negative average risk premium for buyers (scenario 6). This is because buyers (sellers) buy (sell) discounted FTRs (negative risk premium) and benefit from (lose out on) the positive spot price outcome. Likewise, buying an FTR on the FI > EE interconnector across all maturities in the direction from Finland to Estonia would lead to an increased price risk exposure to buyers and a large positive average risk premium (scenario 3). The reasons behind the counter flow pricing on these two interconnectors stem from the fact that there is not a natural flow direction which could be easily predicted ex-ante by the market participants. This is shown in Appendix A, where the spot price differences are relatively equally distributed between positive and negative differences, i.e., 26% and 23% for SE/SE3 > DK1, and 31% and 21% for FI > EE.

Coming back to the eight correctly (naturally) priced risks on the respective interconnectors, we may observe the signs and magnitudes of risk premia in the replicated FTRs. Out of the eight interconnectors and twenty-four averaged contracts only five contain positive risk premia, of which four are for the yearly contracts (SE/SE3 > FI, NO1 > SE/SE3, SE4 > DK2, SE4 > DK2) and one is for the quarterly contract (SE4 > DK2). As a reminder from the above discussion, the positive risk premium indicates a buyer's willingness to pay a mark-up for transferring the transmission risk (in this case more distant in time) to the counterparty. The magnitudes of the positive risk premia are strongly below, or close to 1, but because of the small and varying sample sizes in the yearly and quarterly contract maturities, we cannot test their statistical significance.

The finding of positive risk premia in longer-term contracts, see also [44], seems contrary to the findings of earlier research [59], which has typically associated positive forward risk premia with consumers' higher desire to hedge especially short-term horizons (producers' market power) and negative forward risk premia with producers' higher desire to hedge especially longer-term horizons (consumers' market power). However, the risk premia for the yearly and quarterly maturities in Table 4 exhibit both, negative and positive values, which could be interpreted as neutral risk premium effect.

Nonetheless, it is worth looking closer at the interconnectors with positive risk premia. It can be observed that in three positive risk premia cases the "sink" area is DK2, which has the most of the Danish wind power capacity and the most volatility in area spot prices (see Appendix A). This may explain the market participants' willingness to pay a premium even for the longer-term contracts, implying producers' market power in this case. Positive risk premium in the yearly FTRs for the NO1 > SE/SE3 interconnector with Stockholm (SE/SE3) as the "sink" area may imply a limited supply of such contracts, rather than a greater risk aversion of consumers in the long-term horizon. Magnitude of the yearly SE/SE3 > FI positive risk premium (0.04) is the smallest of all and does not seem to have a clear economic interpretation.

In general, majority of the replicated FTR contracts for the studied time period and interconnectors contain, on average, a negative risk premium. This is particularly true for the monthly FTRs which all contain statistically significant negative risk premium on average. This means that such replicated FTR contracts are, on average, sold at a discount. According to the hedging pressure theory [36,37,60,61] this would imply a market power of consumers, who are exerting greater hedging pressure on producers, who are more keen to sell futures as compared to the lower eagerness of the consumers to buy. This could possibly point out to a lacking demand for cross-border transmission hedging contracts, making the buyers less keen on managing the price difference exposure with FTRs even closer to delivery. However, the negative risk premium pattern has been clear and statistically significant mainly for the monthly FTRs, which are less traded than the quarterly and the yearly contracts. Hence, the ultimate answer on the effect of lacking demand for FTRs on their trading prices has to be left for further research.

## 4. Conclusions and Policy Implications

The long-term prediction of electricity prices and of possible congestions in the electricity networks is difficult, and is arguably becoming more difficult due to the increasing shares of intermittent power generation across Europe and in the rest of the world. This same development is also relevant and noticeable in the Nordic markets. For this reason, among others, the Nordic electricity market participants need efficient hedging mechanisms to manage the price risks that occur in transmission between price areas.

In light of the accepted European network code on forward capacity allocation (FCA), this paper has presented the structure and characteristics of two types of long-term transmission right contracts. These financial contracts are relevant for hedging locational price risks stemming from congestion on electricity transmission lines which interconnect different price areas across the EU. The contract mechanisms assessed are the financial transmission rights (FTR) that are envisioned by the FCA network code, and the electricity area price differentials (EPAD) that are presently used in the Nordic electricity markets. This paper has presented how, by using two EPAD contracts to create a so called "EPAD Combo", the effect of an FTR contract can be replicated. From a policy point of view this replication implies that it is theoretically and even practically possible to continue with the EPAD-based system by using EPAD Combos in the Nordic countries, even if FTR contracts would prevail elsewhere in the EU.

To explore the possible (future) compatibility and even the substitutability of FTR contracts with EPAD contracts for hedging of transmission risks in the Nordic markets, we have examined the pricing accuracy of FTRs replicated from EPADs. We have quantified ex-post forward risk premia for 49 yearly, 172 quarterly, and 487 monthly FTRs sold on ten Nordic interconnectors over eight year period (2008–2013).

The results show that, on average, replicated FTRs contain a negative risk premium and were mostly sold at a discount by producers. It was shown that especially monthly FTRs contained a systematic and statistically significant negative risk premium, which may raise questions on the demand for these FTRs and on the validity of the hedging pressure theory for a non-storable commodity. Two interconnectors (FI > EE, SE/SE3 > DK1) were identified, where the market participants were systematically and across contract maturities unable to correctly(naturally) price the replicated FTR, with respect to the underlying spot price risk. It has been argued that the congestion direction on these interconnectors is more difficult to forecast, which is reflected by the counter flow pricing of the underlying FTRs.

By applying the ex-post forward risk premium methodology, we have quantified the average magnitude and directions of theoretical FTR contracts, which sheds the light on the market's ability to accurately price such a contract and the underlying risk. It was argued that positive and negative risk premia depend on risk aversion, hedging needs, and market shares of market participants, who are willing to pay (accept) a risk premium (discount) pushing prices above (+) or below (−) the risk-neutral expected spread. However, risk aversion and market shares are also influenced by many fundamental factors, such as exceptionally cold, or warm, weather, peak/off peak periods, high/low hydro reservoir inflows, $CO_2$ prices, and transaction costs. For these reasons, a more complex empirical analysis should be carried out that would attempt to disentangle the structure of the identified risk premia.

The empirical results are based on using the official closing prices of the last day of trading before the delivery period for the EPAD contracts used in the FTR replication. One can expect that the last day of the trading period would mean that the markets have the most information available. The official EPAD closing prices do not, however, reflect full market information, as the official closing prices omit the price information from the trades made over-the-counter (OTC). This issue may have an effect on the risk premia results and certainly sheds a light on the reliability of the official EPAD closing prices as a source of price information for the Nordic markets.

From a European policy perspective it can be observed that it is theoretically possible to replicate FTR contracts with a combination of EPAD contracts. In practice, the bi-directional nature of EPAD Combos (and FTRs) makes the pricing of these derivatives less intuitive, when compared to physical contracts, which may sometimes imply that EPAD contracts are not efficient. Policy considerations should be still made with regards to boosting the pricing efficiency of the markets. Another issue that merits policy consideration is changing the mechanism used for the calculation of the daily closing prices for the Nordic EPAD markets.

In this work we have excluded discussions on transaction costs, bid-ask spreads, costs of regulation, rebalancing, and financing. All of these are important issues that are not irrelevant from the point of view of how efficiently the markets for EPAD contracts function.

Some interesting avenues for future work on the pricing efficiency of the EPAD markets and of the replication of FTR contracts with EPAD Combos have been revealed. Namely, there is a clear need for a more holistic investigation of EPAD pricing in terms of historical performance. An example of possible extension, in line with [59,62], is to study risk premia in relation to the price of a hedge (high prices) as well as the number of zonal interfaces between geographical areas (distant locations). Such analysis could reveal whether long-term transmission rights function well only for intra-zonal and adjacent areas or also for more remote areas, as well as whether market participants can receive effective hedge also for the more extreme expected spot outcomes.

**Acknowledgments:** This work was conducted mostly at and supported by the Lappeenranta University of Technology. Petr Spodniak also acknowledges the grant from Science Foundation Ireland (SFI) under the SFI Strategic Partnership Programme Grant number SFI/15/SPP/E3125.

**Author Contributions:** All authors have contributed equally to this manuscript. More specifically, Petr Spodniak was responsible for the methodological design and empirical analysis, Mari Makkonen defined and analysed the cases selected for the analysis, and Mikael Collan contributed generally and specifically to the introduction and conclusion sections of this work.

**Conflicts of Interest:** The authors declare no conflict of interest.

## Abbreviations

The following abbreviations are used in this manuscript:

| | |
|---|---|
| LTR | Long-term transmission rights |
| EPAD | Electricity price area differentials |
| FTR | Financial transmission rights |
| PTR | Physical transmission rights |
| TSO | Transmission system operators |
| ENTSO-E | European network of transmission system operators for electricity |
| ACER | Agency for the Cooperation of Energy Regulators |

## Appendix A

**Table A1.** Statistical summary of hourly spot price differences between area prices during 2006–2013.

| Summary Statistics | SE */SE3 > FI | SE1 > FI | SE2 > SE3 | SE3 > SE4 | NO1 > SE */SE3 | DK1 > DK2 | SE */SE3 > DK1 | SE */SE4 > DK2 | NO4 > FI | FI > EE |
|---|---|---|---|---|---|---|---|---|---|---|
| MEAN | −0.92 | −3.20 | −0.44 | −1.38 | −3.41 | −2.84 | 0.51 | −1.96 | −2.31 | 1.51 |
| SD | 6.49 | 9.20 | 3.49 | 5.37 | 17.60 | 27.45 | 26.92 | 16.42 | 9.25 | 27.35 |
| SKEW | −13.73 | −7.69 | −16.63 | −5.24 | −42.39 | 0.84 | −11.65 | −48.23 | −7.66 | −54.99 |
| KURT | 359.33 | 109.67 | 420.39 | 39.87 | 2692.74 | 2856.13 | 2407.04 | 5237.18 | 135.28 | 3950.30 |
| N | 70,128 | 19,008 | 19,008 | 19,008 | 70,128 | 70,128 | 70,128 | 70,128 | 34,824 | 32,904 |
| >0 | 2544 | 8 | 0 | 1 | 8763 | 6705 | 18,222 | 5000 | 3041 | 10,300 |
| <0 | 6315 | 5133 | 715 | 1871 | 24,330 | 19,313 | 16,089 | 13,133 | 8905 | 6948 |
| =0 | 61,269 | 13,867 | 18,293 | 17,136 | 37,035 | 44,110 | 35,817 | 51,995 | 22,878 | 15,656 |
| % > 0 | 4% | 0% | 0% | 0% | 12% | 10% | 26% | 7% | 9% | 31% |
| % < 0 | 9% | 27% | 4% | 10% | 35% | 28% | 23% | 19% | 26% | 21% |
| % = 0 | 87% | 73% | 96% | 90% | 53% | 63% | 51% | 74% | 66% | 48% |

Note: The table shows hourly spot price differences between interconnected bidding areas as the outcome of day-ahead market auction; MEAN refers to the mean average price difference; SD refers the standard deviation of price differences; SKEW refers to skewness of price differences; KURT refers to kurtoses of price differences; N refers to number of hours in the sample between 2006 and 2013; >0, <0, and =0 refers to number of hours when the price difference was greater than, smaller than, and equal to zero; % > 0, % < 0, and % = 0 refers to number of hours, as a percentage of total hours in the sample, when the price difference was greater than, smaller than, and equal to zero; * SE represents Sweden as a single bidding area until the end of October 2011, after which it was split into four separate bidding zones SE1 Luleå, SE2 Sundsvall, SE3 Stockholm, and SE4 Malmö; Abbreviations for the other bidding zones used in the analysis are: Finland (FI), Estonia (EE), Århus (DK1), Copenhagen (DK2), Oslo (NO1), and Tromsø (NO4).

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