Forward risk premia in long-term transmission rights: The case of electricity price area differentials (EPAD) in the Nordic electricity market

Petr Spodniak [a, b *] Corresponding author
Mikael Collan [c]
[a] *Economic and Social Research Institute (ESRI), Whitaker Square, Sir John Rogerson's Quay , Dublin 2, Ireland*, petr.spodniak@esri.ie
[b] *Trinity College Dublin (TCD), Department of Economics, Dublin 2, Ireland*
[c] *LUT School of Business and Management, Lappeenranta University of Technology, Skinnarilankatu 34, 53851 Lappeenranta, Finland*, mikael.collan@lut.fi

Abbreviations
EPAD Electricity Price Area Differentials
CfD Contract for Difference
FTR Financial Transmission Rights
LTR Long-Term Transmission Rights
NC Network Code
GARCH Generalized autoregressive conditional heteroscedasticity
VECM Vector error correction model
VAR Vector autoregression

ABSTRACT
Hedging behaviour among players in derivatives markets have long been explained by forward risk premia. We provide new empirical evidence from the Nordic electricity market and explore the forward risk premia dynamics on power derivative contracts called electricity price area differentials (EPAD). This contract is critical for the market, but its efficiency has been questioned. The study investigates the significance, direction, and magnitude of forward risk premia in individual bidding areas and contract maturities during the period 2001-2013. We test the hypothesis of a negative relationship between forward risk premia and time-to-maturity, for which we find only partial support.

Keywords: forward risk premia; time-to-maturity; hedging

1. Introduction
This study investigates the issue of systematic differences between the trading prices of electricity as reflected in forward contracts ($F_{t,T}$) and the spot prices observed on the date of delivery ($F_{T,T}$). We call this systematic difference forward risk premia, in line with (Benth and Meyer-Brandis, 2009; Benth, Cartea, and Kiesel, 2008; Marckhoff and Wimschulte, 2009; Longstaff and Wang, 2004). Forward risk premia can be understood as mark-ups, or compensation in derivative contracts charged either by suppliers or consumers for bearing the demand and price risk for the underlying commodity (electricity). The emergence, magnitude, and behaviour of forward risk premia in power derivative contracts are the focus of this paper.

The research topic of forward risk premia is of importance to power producers and consumers, policymakers, as well as academic researchers. We will discuss the relevance for each in turn. First, the absolute and dynamic differences between today's forward price and the expected spot price of electricity have direct impacts on the market participants' (hedgers and speculators) cash flows. That is, by paying a very high or very low risk premia, market participants are exposed to additional uncertainty and financial risks. These financial risks generate market frictions and contribute to increased transaction costs, which adversely affect the competitiveness of factor markets.

Second, policymakers ought to sustain a competitive electricity market, so an awareness of the problems of risk premia in electricity financial contracts is needed. Presence of negative or positive risk premia, in forward contracts does not immediately point to anti-competitive behaviour. Instead, it highlights the exerted pressures from the supply or demand side of the market, and measures the costs for bearing such pressures. Surprisingly, there has only been limited research into the market inefficiencies of the financial electricity market (Redl and Bunn, 2013). Compared to the theoretical and empirical research on inefficiencies in the physical wholesale power markets (Borenstein, Bushnell, and Wolak, 2002; Joskow, 2006; Growitsch and Nepal, 2009), where mark-ups in spot prices are thoroughly examined, the same is not true for power derivatives contracts. Power derivatives markets, like spot markets, are equally susceptible to market inefficiencies. Earlier literature (Hicks, 1939; Lutz, 1940; Keynes, 1930) postulates that the difference between the current forward price and the expected future spot price is negative (negative risk premia), implying there are systematic hedging pressure effects at play.

Nevertheless, recent studies (Bessembinder and Lemmon, 2002; Benth, Cartea, and Kiesel, 2008) describe both positive and negative risk premia that are mainly determined by the behavioural interaction between buyers and sellers, as well as, their risk considerations during different trading periods. Specifically, Benth et al. (2008) formulate a theory of the relationship between forward risk premia and time-to-maturity by predicting decreasing values of risk premia (which eventually become negative) when the time-to-maturity increases. Their theory sheds light on the role of market players' attitudes towards bearing risks during different time periods. Clearly, in order to design efficient market rules and regulations for electricity markets, the risk premia mark-ups in derivatives contracts must be theoretically and empirically understood.

Third, the connection between electricity spot and forward prices is unclear (Benth and Meyer-Brandis, 2009) and the current explanation of forward risk premia in electricity derivatives rests on the assumption of irregular and random behaviour of market participants. Some studies stress the behavioural motives of actors to hedge and diversify risks that explain the forward risk premium and its sign (Benth, Cartea, and Kiesel, 2008; Cartea and Villaplana, 2008). Others (Bessembinder and Lemmon, 2002) explain the forward risk premia as a net hedging cost due to the risk aversion between producers and retailers. Specifically, Bessembinder and Lemmon (2002) state that the forward risk premium in electricity prices depends negatively on the spot-price variance and positively on the standardised skewness of the spot price[1]. This implies that during peak daytime periods, cold winters or transmission bottlenecks, spot prices are often positively skewed, which increases the demand for long forward contracts and hence their prices rise above the expected future spot price (Redl, Haas, Huber, and Böhm, 2009). Similarly, during off-peak periods when electricity demand is low (such as summer periods in Scandinavia), demand risks are low and spot prices are closer to the normal distribution, which pushes the forward contracts below their expected spot-price counterparts. Researchers have found support for these relationships (Lucia and Torró, 2011; Furió and Meneu, 2010; Pirrong and

Jermakyan, 2008; Redl and Bunn, 2013). Some have focused on the market fundamentals that explain the forward risk premia in forward contracts by such determinants as CO_2 prices (Furió and Meneu, 2010) or levels of hydro reservoirs (Lucia and Torró, 2011; Marckhoff and Wimschulte, 2009; Spodniak, Chernenko, and Nilsson, 2014; Fleten, Hagen, Nygård, Smith-Sivertsen, and Sollie, 2015).

In this study, we focus on a specific type of power derivative contract, called electricity price area differentials (EPAD), which enables market participants in the Nordic electricity market to hedge (or speculate) against the local area electricity prices[2]. The reason for studying this particular contract is its unique design and the exceptional role it plays in the European and global electricity markets. According to the two main EU electricity network codes (NC) designed by ENTSO-E (NC on Forward Capacity Allocation, and NC on Capacity Allocation and Congestion Management), an alternative mechanism to hedge local electricity prices, called financial transmission rights (FTR), should be implemented EU-wide. The Nordic EPAD contracts have so far received an exception from the planned FTR mechanism, under the assumption that "appropriate cross-border financial hedging is offered in liquid financial markets on both side(s) of an interconnector" (ACER, 2011, p. 10). However, the liquidity assumption of EPAD has been questioned (NordReg, 2010; Hagman and Bjørndalen, 2011; Spodniak, Collan, and Viljainen, 2015). As expected, EPAD liquidity may impact the risk premia buyers (sellers) are willing to accept (charge) for bearing the price risk (demand risk).

Both EPAD and FTR are financial derivative contracts that fall into the group of long-term transmission rights (LTR) that provide market participants the possibility to reduce, or share transmission congestion risks. While FTR hedge the electricity price difference between two bidding areas, EPAD hedge the difference between the local area price and a reference system price. It falls beyond the scope of this study to address the FTR, which are currently mainly implemented in power markets with nodal pricing, such as the US. For a theoretical discussion on European FTR, see Spodniak et al. (2017). For the remainder of this paper, we focus solely on EPAD in the Nordic electricity market, starting with a brief overview.

In liberalized and deregulated electricity markets, power producers compete for the limited capacity of the transmission network to supply power to customers. Because of the diverse operational conditions of the power system, transmission networks can become congested and consumers are prevented from accessing power from the most efficient producers. To address the problem of limited transmission capacity, congestion management and tradable long-term transmission rights (LTR) are integral to the fundamentals of power market designs. EPAD is a financial contract with weekly, monthly, quarterly, and yearly maturity, traded on Nasdaq OMX Commodities, and used for hedging the price difference between a specific bidding area and a reference system price, in the Nordic electricity market. The system price is an equilibrium price of the whole Nordic electricity market, where bids and offers from players across seven countries (Norway, Sweden, Finland, Denmark, Estonia, Latvia, and Lithuania) discover electricity prices for each hour of the following day. As part of congestion management, the Nordic electricity market uses a zonal pricing model, which splits geographical regions (countries) into multiple bidding areas (currently fifteen) that are selected to reflect the transmission congestion between neighbouring regions. Hence, area prices represent the marginal cost of congestion and the system price is the reference price for the entire market.

A major challenge with quantifying risk premia with traditional forward pricing methods (e.g., buy-and-hold) is that these methods are not applicable to non-storable goods and commodities, such as electricity. Electricity systems rely on a constant balance of supply and demand (Kirchhoff's laws), as current technologies limit economic storage of large quantities of electrical energy. Hence, the forward electricity price is usually defined as the *expected price* of the commodity at delivery conditioned on an information filtration (Benth, Cartea, and Kiesel, 2008; Benth and Meyer-Brandis, 2009) plus the *risk preferences* of market participants as reflected in risk premia (Breeden, 1980; Cootner, 1960; Dusak, 1973). To quantify the risk premia in EPAD contracts, we revisit the ex-post approach (Marckhoff and Wimschulte, 2009; Longstaff and Wang, 2004; Shawky, Marathe, and Barrett, 2003) and define the ex-ante risk premia as the differential between observed forward prices and delivery-date spot prices, as revealed ex-post. We quantify risk premia in EPAD for the time period 2001-2013 using daily financial price data from Nasdaq OMX Commodities and daily spot-price data from Nord Pool Spot. Despite the fact that EPAD is a standardized defered settlement futures contract, we use the term forward risk premia, or simply risk premia, because of its established usage in finance.

There are three main objectives of this paper. First, due to the limited research on electricity price area differentials (EPAD), this paper contributes empirical evidence on risk premia in EPAD to support academic and policy discussion on long-term transmission rights in Europe. Second, due to the indeterminate evidence on the factors affecting risk premia in power derivatives, this work investigates the significance, direction, and magnitude of risk premia according to location, delivery periods, and time-to-maturity in the Nordic electricity market. Third, the work scrutinizes the time-evolution of forward risk premia and tests on the Nordic electricity market the theory (Benth, Cartea, and Kiesel, 2008), which predicts decreasing values of risk premia (eventually turning negative) as the time to maturity increases.

Our main contribution lies in expanding the scale and scope of the limited theoretical and empirical research on transmission risks and forward risk premia in power derivatives markets. By quantifying forward risk premia in EPAD according to location, delivery period, and contract type, we present new and comprehensive empirical evidence to energy policymakers and academics. Furthermore, we introduce research of a new timeframe (2001-2013) that is characterized by fundamental market changes, such as the implementation of EU ETS, the introduction of the 3rd Energy Package, and market size changes (by the inclusion of Estonia, Lithuania, and Latvia), and splitting of Sweden and Norway into multiple bidding zones. Our study also provides validation for earlier findings on the determinants of forward risk premia (Marckhoff and Wimschulte, 2009) and on the relationship between forward risk premia and time to maturity (Benth, Cartea, and Kiesel, 2008). Methodologically, we improve the forecast precision by using daily frequency data, in comparison to earlier studies that relied on monthly averages (Kristiansen, 2004b; Redl and Bunn, 2013; Furió and Meneu, 2010).

This paper is structured as follows. The next section presents a brief literature review on spot and forward electricity pricing, and identifies the theoretical gap in current knowledge on risk premia. Section 3 opens up the methodology for deriving ex-ante and ex-post risk premia. Section 4 illustrates the hedging strategies from the power producer, consumer, and speculator's perspective. Section 5 analyses the identified risk premia in EPAD, with a discussion of the impact of liquidity and time-to-maturity on risk premia. The paper ends with conclusions and policy implications in section 6.

2. Literature review

Electricity pricing in general, and the link between spot prices and forward prices in particular, is defined by two primary literature streams: industrial organization and finance theory. The former addresses the impact of forward contracting, which has been shown to reduce market power, and spot prices (Allaz, 1992; Wolak, 2000), and generate competitive outcomes in a Cournot duopoly setting (Allaz and Vila, 1993). However, the theory fails to explain the sign of the forward risk premium as well as the potential impact of lower spot prices on forward contracts. The latter theory explains the wholesale electricity prices by different state factors, such as demand and capacity (Cartea and Villaplana, 2008), or demand and fuel price (Pirrong and Jermakyan, 2008). In this stream, an increasing research interest is devoted towards the role of market players' attitudes towards bearing risks during different time periods. For instance, Benth et al. (2008) illustrate the linkages among market risk premia, market players' risk preferences, and the market price of risk. Furió and Meneu (2010) present some evidence on market players' decision-making as captured by forward premia.

These studies are heavily influenced by the seminal work of Bessembinder and Lemmon (2002), who modelled the economic determinants of market clearing forward power prices based on equilibrium considerations. Bessembinder and Lemmon also stated that the forward risk premium, defined as the difference between observed forward prices and the expected delivery date spot prices, relates negatively to the spot-price variance and positively to the standardized skewness of the spot price. Table 1 provides an overview of additional empirical studies dealing with price risks in spot and forwards electricity markets. Even though most of the studies go well beyond testing only single-factor impacts on risk premia, the evidence is inconclusive and often tied to a context-specific setting in a narrow timeframe. The timeframes of the studies listed in Table 1 underscore the value of the large scale (2001-2013) and scope (multiple countries, bidding areas, and contract maturities) of our study sample.

Table 1: Summary of studies on price risks in electricity markets

Study	Region	Model	Data	Results	Time frame
Marckhoff and Wimschulte (2009)	Nordic	Electricity forward pricing model; ex-post calculation of risk premia	Daily baseload prices as underlying of 251 CfD contracts with monthly, quarterly, seasonal and yearly delivery periods	CfDs contain adequate risk premia reflecting market efficiency; hydropower significantly impacts area price spreads; risk premia positively (negatively) related to skewness (variance) of spot price	2001-2006
Haldrup and Nielsen (2006)	Nordic	Regime-switching long-memory model	Hourly area spot price studied in non-congested and congested time periods depending on direction of congestion	Price dynamics and long memory of price differ across areas; fractional cointegration	3 January 2000-25 October 2003
Worthington, Kay-Spratley, and Higgs (2005)	Australia	Multivariate GARCH	Daily spot prices on half-hourly basis;	NEM regional spot markets are non-integrated and inefficient; presence but no mean spillovers of price volatility between areas; shocks in on market affect price volatility in another market	13 December 1998 – 30 June 2001
Hadsell and Shawky (2006)	US-NYISO	GARCH	Day-ahead and real-time market prices; daily average aggregation of peak hour prices (7am-11pm); MC congestion; MC losses	Price volatility higher in real-time market than day-ahead; premium levels across zones inversely related to levels of congestion	Jan 2001-June 2004
De Vany and Walls (1999)	US- west	Vector error correction and cointegration analysis (VECM)	Peak and off-peak electricity spot prices	Efficient and stable power market	1994-1996
Longstaff and Wang (2004)	US-PJM	Vector autoregressive model (VAR)	Daily average of hourly spot prices; day-ahead electricity forward price; electricity load and weather conditions	Risk premia of electricity futures are positive, but vary; forward premia are negatively related to price volatility and positively related to price skewness	June 1 2000-November 30, 2002
Kristiansen (2004a)	Nordic	Electricity forward pricing model; ex-post calculation of risk premia	Seasonal and yearly CfD contracts	Most CfDs contain significant risk premia (difference between average CfD prices and the average difference between area and system price during delivery); positive premia attributed to risk-averse consumers, whereas negative premia attributed to risk-averse hydro-producers.	November 2000–December 2003
Kristiansen (2004b)	Nordic	Electricity forward pricing model; ex-post calculation of risk premia	Seasonal CfD contracts	Most CfDs contain significant risk premia (difference between average CfD prices and the average difference between area and system price during delivery); positive premia attributed to risk-averse consumers, whereas negative premia attributed to risk-averse hydro-producers.	November 2000 – April 2002

3. Methodology

Due to the technical and economic limitations of storing electricity, the traditional theory of storage is not applicable to pricing electricity derivatives. Instead, the price of electricity derivatives is determined by *expectations* and *risk preferences* of market participants (Breeden, 1980; Cootner, 1960; Dusak, 1973)[3]. Risk premia represent a premium (discount) that buyers (sellers) of futures contracts are willing to pay (accept) in addition to the expected future spot price in order to eliminate the risk of unfavourable future spot-price movements (Marckhoff and Wimschulte, 2009, p. 263). This approach states *ex-ante* that the futures price $\mathrm{F_{t,T}}$ is determined by the expected future spot price $\mathrm{E(S_T|\Omega_t)}$ and the risk premia $\mathrm{\pi_t^F}$ where Ω_t is the information set available at time *t*.

$$F_{t,T} = E(S_T|\boldsymbol{\Omega}_t) + \pi_t^F \qquad (1)$$

It is common practice in the forward and futures pricing literature (equity, foreign exchange, fixed income derivates) to calculate the ex-ante premium in the forward price as the *ex-post* differential between the observed futures prices and the realized delivery-date spot prices (Shawky, Marathe, and Barrett, 2003)[4]. Longstaff and Wang (2004) suggested this ex-post approach to risk premia by using $\mathrm{S_T}$ as a proxy for $\mathrm{E_t(S_T)}$, and Marckhoff and Wimschulte (2009) applied this proxy to calculate the ex-post risk premia for CfD (EPAD). In our study, we too embrace the ex-post methodology to risk premia.

More specifically, during each day of the delivery period, the holder of a long EPAD position receives a payoff which is similar to receiving the area spot price and paying the system spot price. In contrast, a holder of a short EPAD position receives during the delivery period a payoff akin to paying the area price and receiving the system price. Kristiansen (2004a) regards ex-post risk premia as the difference between average EPAD prices and the average difference between the area and system prices during the delivery period. Another ex-post approach employed by Marckhoff and Wimschulte (2009) examines the risk premia on a daily basis instead of averaging the ex-post premia. The latter approach enables assessment of EPAD's development throughout the contract's duration. By rearranging Equation 1, we can write that EPAD risk premium at time t for delivery at T equals the *present* price of EPAD contract at the time t for delivery at T minus the *expected* price of EPAD contract at time T for delivery at T. This is represented formally in Equation 2.

$$\pi_t^{EPAD} = EPAD_{t,T} - E_t(EPAD_{T,T}) \qquad (2)$$

To further open up the calculations, Equation 3 states that EPAD risk premium at time t, for delivery at T, equals to EPAD price at time t for delivery at T minus the average realized difference between the area price and the system price during the delivery period between $\mathrm{T_1}$ and $\mathrm{T_2}$. The premium for each delivery period (year/month/quarter/week) and area is computed *separately*. In this study, we use the following equation for the ex-post EPAD risk premia:

$$\pi_t^{EPAD} = EPAD_{t,T} - \frac{1}{T_2 - T_1}\sum_{h=T_1}^{T_2}(P_h^{Area} - P_h^{System}) \qquad (3)$$

where π_t^{EPAD} is the risk premium; $EPAD_{t,T}$ is the closing price of the EPAD contract on day *t* for delivery in period *T*; P_h^{Area} and P_h^{System} are the spot area and system prices at hour *h*, respectively; T_1 and T_2 stand for the start and end of the delivery period, respectively; and $T_2 - T_1$ represents the duration of the delivery period, in hours.

4. Risk management strategies in the Nordic electricity market

Market participants can hedge against transmission risks by locking in an electricity price via combinations of contracts. In particular, power *generators* hedge income streams by selling system futures, which protects them against the energy risk in the form of system price fluctuations. In addition, if they identify transmission risk as a threat, they can sell EPAD contracts to avoid increased volatility that stems from the area price differences, which they face during the spot market operation. The resulting cash flow can be positive or negative, depending on the market outcome during the delivery period.

Electricity *retailers* hedge the risk of selling electricity at fixed prices to the end-customers, while unaware of the exact quantity of electricity demanded. In many cases, households are still charged according to their average load profiles, rather than on their time of consumption. Despite the increasing deployment of smart meters across the EU (target of 80% by 2020), the price risks remain a pressing issue for the retailers without hourly, or spot price based contracts with end-customers. This practice is clearly contingent on where the customers are located. For example, Norwegians are more prone to time-based pricing than the Swedes (NVE, 2012). For these reasons, retailers buy both system futures contracts and EPAD contracts, in order to have a complete hedge against the area spot-price volatility.

Finally, electricity *traders* (speculators) aim to foresee profitable trades between specific bidding areas. Their actions inherently aid market liquidity (more bids and offers) and price stability. An EPAD trader sells a contract in a trade origin (e.g., in Copenhagen) and buys the same maturity contract for the same time period in a trade destination area (e.g., in Stockholm). In simplified terms, traders benefit when the spot-price difference in the trade origin is smaller during the delivery period than the price of EPAD they sold; that is, there's no need to pay the positive difference to the counterparty. Vice versa, traders benefit if the spot-price difference in the trade destination is higher during the delivery period than the price of EPAD they bought; that is, they receive the positive difference from the counterparty. However, the total profitability of the speculation is dependent on multiple factors, such as the amount of expiry market settlement, the magnitude of price movements during the delivery period, transaction costs, and market liquidity.

To illustrate, we take the average daily prices from Nord Pool Spot day-ahead market (Elspot) during one sample day (14/8/2014) and show the theoretical hourly cash flow for each market participant. For simplicity, we omit any intermediate cash flows and consider a one-period setup, i.e., hedging a volume of 1 MW during each hour of a single day (24 hours). Figures 1-3 summarize the theoretical outcomes for the main market participants: generators, retailers, and traders (speculators)[5].

There are three steps in the scenario[6]. First (T-2), market participants trade the system futures and EPAD contracts; second (T-1), the system price and area prices are discovered; third (T), profit and loss are calculated based on the values from T-2 and T-1. As is visible from the scenarios, the economic results for generators, retailers, and traders depend on the *bundles* of EPAD and system futures contracts. The hedged total amount (system futures + EPAD) locks-in the total price and protects its owner against the more volatile spot market outcome. Assuming that the generator selling electricity on the spot market is an area's marginal generator, where their bidding price represents short-run marginal costs, their total profit will be equal to the total amount hedged (sold) minus the production area spot price during delivery.

Similarly, if retailers sell power to their end-customers in the consumption area for the local spot price, their profit is equal to the consumption area's spot price, less the total amount hedged (bought). Both generators and retailers can make profits or losses on their hedging strategies, depending on their forecasting acuity, composition of their generation fleet, contract terms with end-users, and so on. Speculators do not possess any physical power production facilities; neither do they have contracts with end-customers. Speculators focus on EPAD price movements and aim to correctly identify short-term profitable trades on various EPAD bundles. For taking on the EPAD price risk without any underlying assets (generation, end-customers), speculators are exposed to higher than average risks in the hope of securing above-average profits. At the same time, speculators improve the market liquidity by representing additional counterparty for hedgers (generators and retailers), which improves market efficiency via lower bid-ask spreads.

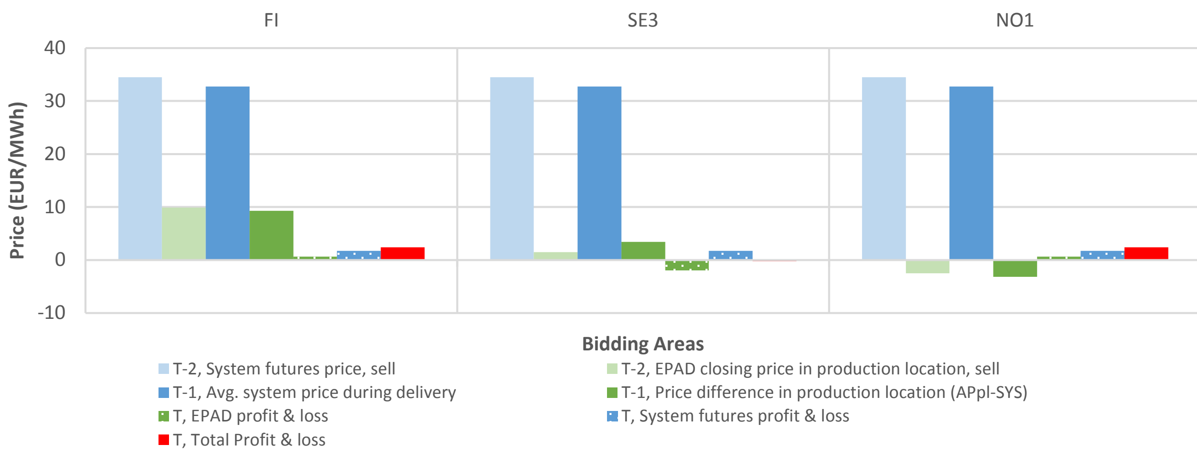

Figure 1: Market outcomes for generators selling system futures and selling EPAD in production location *(Double Column Figure)*

Note: Theoretical cash flow, calculated ex-post, from trading 1MW in three selected bidding areas during a sample day 14/8/2014.

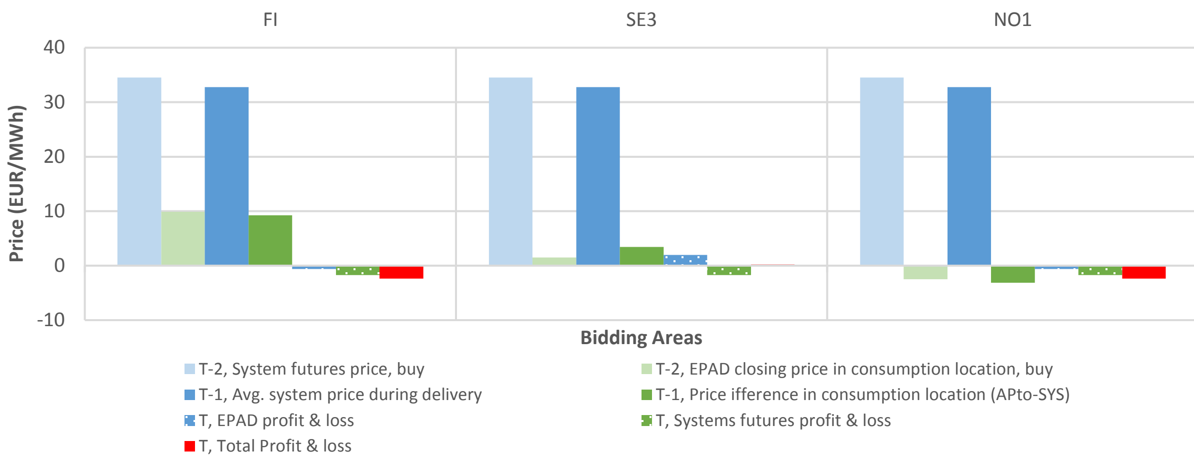

Figure 2: Market outcomes for retailers buying system futures and buying EPAD in consumption location *(Double Column Figure)*

Note: Theoretical cash flow, calculated ex-post, from trading 1MW in three selected bidding areas during a sample day 14/8/2014.

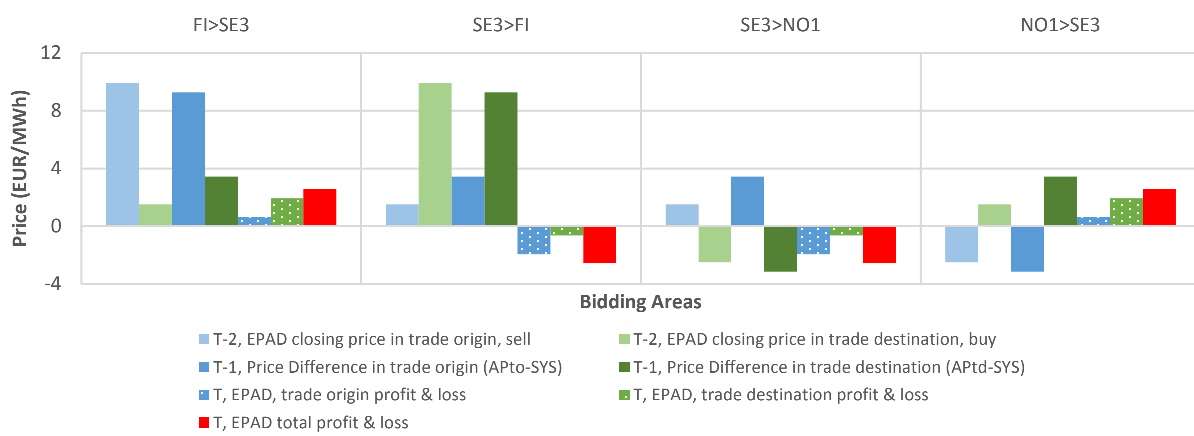

Figure 3: Market outcomes for traders (speculators) selling EPAD in trade origin and buying EPAD in trade destination *(Double Column Figure)*

Note: Theoretical cash flow, calculated ex-post, from trading 1MW in three selected bidding areas during a sample day 14/8/2014.

What is also apparent from the Figures 1-3 is that generators and retailers are each other's counterparties, which is in contrast to financial transmission rights (FTR), where most commonly the transmission system operator (TSO) acts as the counterparty. The TSO's role as a counterparty is understood to reduce forward premia, which is why EPAD Combos have recently received attention (Nasdaq OMX, 2013). Such contracts would blur the following two main differences between FTR and EPAD. The first difference is that EPAD have no connection to the congestion rent collected by the TSO during cross-border congestion, whereas FTR are issued directly by TSO, which redistributes the collected congestion rent (Kristiansen, 2004a). Second, FTR hedge the price difference between bidding zones, whereas EPAD hedge the price difference between a bidding zone and the reference system price.

5. Ex-post analysis of forward risk premia in electricity price area differentials (EPAD)

In this section, we estimate the forward risk premia in EPAD contracts according to the ex-post methodology discussed above. In order to first distinguish the identified forward risk premia from zero, we test their statistical significance with respect to EPAD maturity (month, quarter, and year), trading location (bidding area), and trading time. Further, because market liquidity is an underlying driver behind bid-ask spreads, which further impact the cost of EPAD for market participants, we deem necessary to highlight some empirical facts of our sample, with respect to liquidity. Lastly, we test the theory of negative relationship between forward risk premia and time-to-maturity by regression analysis. We discuss the empirical findings and compare these to the current theory.

5.1 Risk premia in EPAD

We begin by testing the presence of non-zero ex-post risk premia in EPAD contracts by estimating the mean risk premium α for the individual maturities and bidding areas based on the regression equation (4). The null hypothesis H0: $\alpha = 0$ is tested against the alternative hypothesis H1: $\alpha \neq 0$.

$$EPAD_{t,T} - E_t\left(EPAD_{T,T}\right) = \alpha + \varepsilon_t \quad (4)$$

We use the same formula as Furió and Meneu (2010) who find a statistically insignificant figure of -0.04 EUR/MWh risk premium in their overall sample (4 February 2003 - 31 August 2008) of the Spanish monthly forward contracts. After graphical inspection, they split the sample into two periods with prolonged negative and positive risk premia, which are proven to be statistically significant (-9.17 EUR/MWh and 2.81EUR/MWh). As shown in Table 2, we also discover that EPAD contracts contain significant risk premia, which vary in sign and magnitude across contract types, areas, and years. Most of the average yearly premia in each bidding area are significantly different from zero at 5% significance level, except for specific area, year, and contract combinations.

From the statistical properties of risk premia in EPAD contracts, displayed in Table 2, we highlight the following two points. First, the highest volatility of risk premia (standard deviation) is observed in the most popular quarterly and monthly contracts as a percentage of total contracts. These contracts include more frequent extreme values that disperse the distribution from the mean risk premia and drive volatility upward. The highest risk premia volatility is observed in Århus (DK1) and Copenhagen (DK2) for quarterly and monthly contracts, especially in the years 2008, 2010, and 2011. The lowest volatility in risk premia is observed in the contracts with longer maturity (seasonal and yearly), especially during the initial six years after EPAD were introduced to the market (2001-2006). This also stems from the low liquidity during this period, as discussed in further detail in the next section.

Second, we look at the magnitude and direction of the risk premia. Denmark is a country with the highest (positive) mean risk premia, especially in Århus where, for instance, yearly 2010 EPAD contract contained a significant risk premium of 13.74 EUR/MWh (see Figure 4). This in practice means that, if buyers of Århus 2010 yearly EPAD bought a volume of 1 MW for 15.75 EUR (highest deal price, 15.10.2008), they would have to pay the seller a total of 107,748 EUR ((3.45 – 15.75)*1 MW*8760h) in 2010[7].

In practice, this hedge costs 295.20 EUR per day or 12.30 EUR per hour. Nonetheless, the majority of buyers and sellers hold the offsetting sides of the trade (hedgers), which minimizes their total exposure towards price (energy and transmission) fluctuations. Hence, even though the buyers of Århus 2010 yearly EPAD paid more for the transmission risk hedge, they pay less for the energy risk hedge; that is, the contracts for energy either on the spot or futures market are less expensive. The sellers of Århus 2010 yearly EPAD received a positive cash flow from selling the EPAD contract, but due to the low energy prices, obtain less from selling the physical energy on the spot market. On the negative side of risk premia, we observe the highest values for Helsinki and Oslo areas, especially for the contracts with yearly maturity.

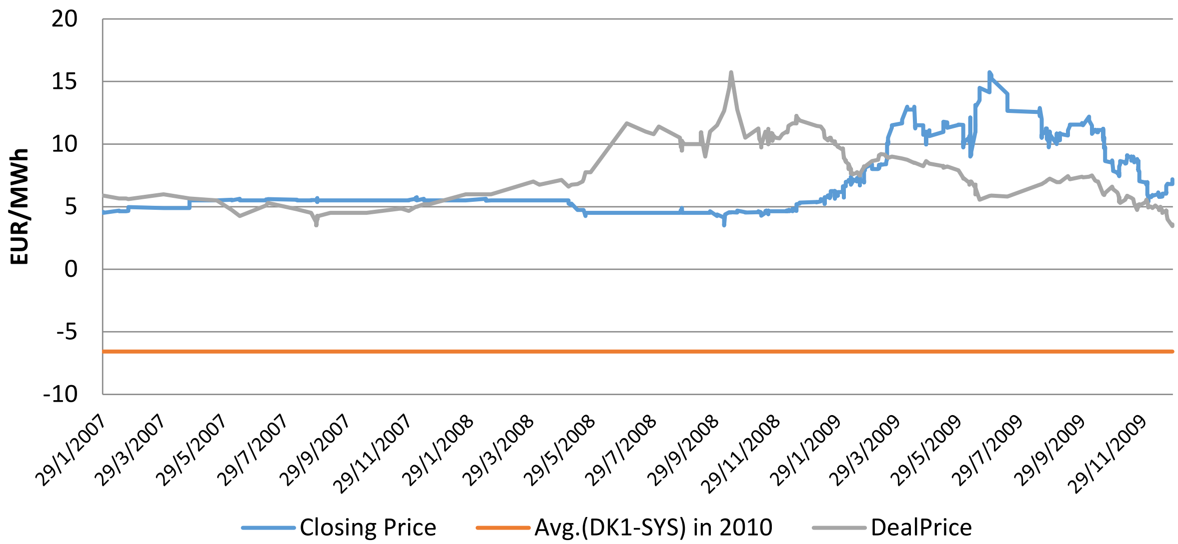

Figure 4: Run-chart of closing price, deal price (OTC and Exchange), and average ex-post difference (DK1 – system price) in Århus (DK1) yearly EPAD for 2010 (SYARHYR-10) *(Double Column Figure)*

Finally, the hydro level conditions must be discussed due to the essential role of hydropower in the Nordic energy market. Deviations from the current hydro storage levels (in percentages of total) from their historical median, tend to increase or decrease the Nordic system price (Spodniak, Chernenko, and Nilsson, 2014; Bühler and Müller-Mehrbach, 2007). Drier years were 2002-03, 2006-07, and 2010-11, while years with higher precipitation were 2007-08 and 2011-12. During the drier time periods, hydro producers reduce output to preserve the scarcer energy source, while more plants with higher marginal cost are operating. The cross-border flow also tends to go toward the hydro-dominated bidding areas during the dry years. The impact of dry hydro years on the risk aversion of market participants depends on multiple factors.

The relative (buyer vs. seller) risk aversion regarding cross-border price differences will be affected by congestion-based transmission risk in an export or import oriented area. Generators may be more risk-averse in an export-oriented area with area prices very close to, or below the system price. This may lead to negative risk premia, due to greater hedging pressure of the buyers over sellers. With the increasing risk of area price hikes, retailers and large electricity users may become more risk-averse and their risk aversion may change. In this case, sellers could exert greater hedging pressure over buyers in commanding positive risk premia in EPAD contracts.

Table 2: Ex-post risk premia in EPAD - mean and standard deviation in parentheses ()

	Delivery period	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Århus (DK1)	Month	-	-	-	-	-	-	-1.94 (4.97)	2.23 (6.99)	2.44 (2.92)	5.11 (9.41)	-0.91 (6.53)	2.86 (4.1)	-0.54* (5.92)
	Quarter	-	-	-	-	-	9.05 (6.41)	-2.02 (3.52)	-3.63 (9.75)	6.28 (3.6)	9.54 (7.74)	0.4** (7.82)	1.34 (4.52)	2.08 (2.74)
	Winter 1	2.46 (0.2)	-1.32 (0.25)	6.2 (7.32)	-1.16 (1.33)	-0.45 (0.93)	-	-	-	-	-	-	-	-
	Summer	0.72 (1.81)	-1.5 (0.78)	-2.33 (1.27)	1.23 (0.8)	-5.5 (1.33)	-	-	-	-	-	-	-	-
	Winter 2	-1.39 (0.52)	14.25 (0.24)	1.72 (1.06)	1.12 (0.48)	-5.58 (1.32)	-	-	-	-	-	-	-	-
	Year	-	1.95 (0.29)	3.38 (2.27)	-0.27 (0.5)	-5.55 (0.6)	9.81 (1.52)	-0.6 (3.33)	-7.16 (0.52)	5.72 (2.52)	13.74 (2.44)	6.11 (3.82)	1.62 (2.02)	5.44 (0.85)
Copenhagen (DK2)	Month	-	-	-	1.05 (1.05)	-0.92 (5.53)	4.45 (4.23)	0.01* (3.47)	1.72 (7.11)	0.47 (5.55)	-1.13 (6.6)	1.63 (8.81)	3.46 (4.96)	1.95 (2.56)
	Quarter	-	-	-	-	-	6.84 (6.01)	-0.63 (4.24)	-3.14 (8.22)	3.81 (5.85)	0.84 (5.28)	1.49 (8.9)	2.69 (5.7)	3.65 (4.14)
	Winter 1	-	-1.38 (0.52)	1.9 (0.69)	1.36 (0.24)	-2.14 (0.14)	-	-	-	-	-	-	-	-
	Summer	0.77 (0.17)	-0.59 (0.77)	-0.07 (0.8)	1.94 (0.52)	2.08 (1.37)	-	-	-	-	-	-	-	-
	Winter 2	-1.22 (0.19)	2.72 (0.26)	0.72 (0.48)	1.36 (0.19)	-8.38 (1.27)	-	-	-	-	-	-	-	-
	Year	-	-0.89 (0.45)	1.37 (0.49)	1.56 (0.4)	-3.1 (0.09)	5.21 (1.84)	1.16 (3.89)	-6.71 (0.91)	2.78 (3.37)	3.97 (2.61)	5.73 (3.06)	1.45 (1.86)	6.24 (1.26)
Helsinki (FI)	Month	-	-	-	0.79 (0.58)	-0.18 (1.11)	0.67 (1.86)	-0.6 (3.37)	-0.45 (4.66)	-0.08** (3.34)	-2.41 (7.3)	1.28 (4.66)	1.76 (3.5)	0.74 (3.56)
	Quarter	-	-	-	-	-	0.96 (1.67)	-1.28 (3.19)	-3.69 (5)	0.4 (2.69)	-2.31 (5.17)	0** (3.84)	-0.41 (2.69)	2.08 (3.24)
	Winter 1	1.39 (0.07)	0.23 (0.18)	2.32 (0.48)	1.55 (0.39)	-0.54 (0.11)	-	-	-	-	-	-	-	-
	Summer	1.69 (0.62)	-1.34 (0.24)	1.12 (0.51)	1.5 (0.31)	-0.27 (0.61)	-	-	-	-	-	-	-	-
	Winter 2	-0.1 (0.19)	2.81 (0.1)	2.21 (0.13)	0.78 (0.36)	-1.34 (0.32)	-	-	-	-	-	-	-	-
	Year	-	0.08 (0.14)	2.1 (0.08)	1.56 (0.14)	-0.97 (0.2)	1.05 (0.37)	-1.35 (0.28)	-5.4 (0.29)	-0.51 (0.88)	-2.39 (0.42)	-0.81 (0.39)	-3.52 (0.97)	0.05** (1.82)
Oslo (NO1)	Month	-	-	-	-0.16 (0.5)	0.02** (0.28)	0.05** (1.24)	1.32 (3.19)	1.06 (4.35)	-0.02** (2)	-0.7 (3.48)	1.09 (2.81)	-0.05** (1.77)	-0.67 (1.83)
	Quarter	-	-	-	-	-	-0.43 (0.84)	2.25 (3.17)	3.7 (5.2)	-0.03** (1.35)	-1.48 (1.85)	1.1 (2.24)	0.66 (1.44)	-0.58 (1.35)
	Winter 1	-0.54 (0.06)	0.05 (0.06)	-0.89 (0.47)	-0.22 (0.13)	0.62 (0.07)	-	-	-	-	-	-	-	-

	Summer	-0.27 (0.23)	0.71 (0.16)	0.56 (0.35)	-0.34 (0.06)	0.03 (0.38)	-	-	-	-	-	-	-	-
	Winter 2	0.21 (0.1)	-0.39 (0.08)	-0.25 (0.16)	-0.02 (0.07)	-0.1 (0.14)	-	-	-	-	-	-	-	-
	Year	-	0.3 (0.06)	-0.48 (0.23)	-0.24 (0.07)	0.45 (0.07)	-0.76 (0.1)	2.62 (0.36)	5.31 (0.51)	0.92 (0.59)	-1.54 (0.44)	0.38 (0.34)	1.42 (0.38)	0.21 (0.42)
¤Stockholm (SE/SE3)	Month	-	-	-	0.96 (0.72)	0.36 (0.5)	1.08 (1.44)	-1.26 (3.21)	-0.81 (4.63)	0.01** (3.31)	-2.68 (7.14)	2.71 (2.93)	1.78 (1.86)	0.47 (2.42)
	Quarter	-	-	-	-	-	1.14 (0.84)	-1.8 (3.04)	-4.17 (5.01)	0.17* (2.51)	-2.7 (5.7)	1.17 (1.94)	1.86 (1.62)	0.77 (2.44)
	Winter 1	1.11 (0.1)	0.15 (0.25)	1.53 (0.1)	1.28 (0.15)	-0.2 (0.08)	-	-	-	-	-	-	-	-
	Summer	1.33 (0.5)	-1.28 (0.15)	-0.2 (0.26)	1.23 (0.24)	0.35 (0.29)	-	-	-	-	-	-	-	-
	Winter 2	-0.22 (0.15)	0.76 (0.11)	0.9 (0.14)	1.23 (0.11)	0.18 (0.21)	-	-	-	-	-	-	-	-
	Year	-	-0.42 (0.16)	0.73 (0.07)	1.31 (0.12)	-0.08 (0.08)	1.22 (0.17)	-1.88 (0.21)	-5.92 (0.14)	-1.06 (0.8)	-3.09 (0.27)	0.1 (0.39)	0.31 (0.83)	0.58 (0.71)
Luleå (SE1)	Month	-	-	-	-	-	-	-	-	-	-	0.32 (0.8)	-0.59 (1.46)	-0.34 (2.21)
	Quarter	-	-	-	-	-	-	-	-	-	-	-	-0.72 (0.96)	-0.83 (1.76)
	Year	-	-	-	-	-	-	-	-	-	-	-	-0.98 (0.3)	-1.37 (0.44)
Sundsvall (SE2)	Month	-	-	-	-	-	-	-	-	-	-	1.1 (0.78)	-0.62 (1.45)	-0.33 (2.22)
	Quarter	-	-	-	-	-	-	-	-	-	-	-	-0.55 (1.02)	-0.82 (1.75)
	Year	-	-	-	-	-	-	-	-	-	-	-	-0.55 (0.29)	-1.31 (0.48)
Malmö (SE4)	Month	-	-	-	-	-	-	-	-	-	-	8.4 (3.04)	3.6 (3.66)	1.31 (2.83)
	Quarter	-	-	-	-	-	-	-	-	-	-	-	5.02 (2.95)	2.91 (3.3)
	Year	-	-	-	-	-	-	-	-	-	-	-	4.63 (1.74)	5.22 (1.61)
¤Tromsø (NO3/NO4)	Month	-	-	-	-	-	-	-	-	-	-	1.2 (1.02)	-0.46 (0.94)	0.05 (0.74)
	Quarter	-	-	-	-	-	-	-	-	-	-	-	-0.28 (0.62)	-0.71 (0.69)
	Year	-	-	-	-	-	-	-	-	-	-	-	-0.01 (0.3)	-0.74 (0.3)

Note: All values are given in EUR/MWh and significant at 5%, except values marked with * and ** referring to significance at 10% and non-significance, respectively. ¤Tromsø was NO3 before 10.1.2010 and NO4 thereafter; *SE/SE3 combines data for Sweden before the split (SE) into four areas in Nov.2011 and the Stockholm area (SE3) thereafter.

5.2 Note on liquidity of EPAD

Together with safety, liquidity is a principle of investment strategies; see for instance the 2014 AFP Liquidity Survey (RBS Citizens Bank, 2014). Liquidity is the ability to quickly transact at low cost and with minimal effect on prices. Liquidity and clearing have much in common, especially in the case of EPAD. Since the great majority of EPAD trading volume is traded over-the-counter (OTC) and the daily fix price is calculated on the basis of exchange-based trades only, the importance of the role of exchange-based trading can be questioned and the representativeness of the daily fix is undermined (Spodniak, Collan, and Viljainen, 2015). In fact, there are reasons to be sceptical about results obtained when the daily fix price is used in analyses of EPAD contracts. The inclusion of OTC-based trades would add to the reliability of the obtained results. Churn rates (Spodniak, 2015), bid-ask spreads (Wimschulte, 2010), and open interest are all relevant measures of liquidity in electricity markets. In this study, we highlight the development of open interest, which is defined as the number of open contracts that have not yet been liquidated. Specifically, open interest represents the total number of contracts, either long or short, that have been entered into and not yet offset by delivery. Each open transaction has a buyer and seller, but for calculation of open interest, only one side of the contract is counted.

Figure 5 displays the development of open interest in EPAD over the period spanning 2006-2013, with the break-down by contract maturity. The figure illustrates the general growth period from 2006 to 2009, when the open interest went from 40 TWh up to slightly below 100 TWh, where the level has stabilised. The expansion is most likely due to the product restructuring and the change of the trading currency in 2006. The three seasonal contracts of unequal length were replaced with standardized quarterly and monthly contracts, while the yearly contracts have been preserved[8]. The currency of trading was changed from the Norwegian Krone to the Euro for products with delivery dates of 1 January 2006 and beyond. Figure 5 also shows that behind the EPAD growth in open interest from 2010 onward, were mainly the yearly contracts and to a lesser extent the monthly contracts. Further, the figure illustrates the cascading effect of yearly contracts being split into quarterly contracts and the quarterly contracts cascading into monthly contracts, before their respective delivery.

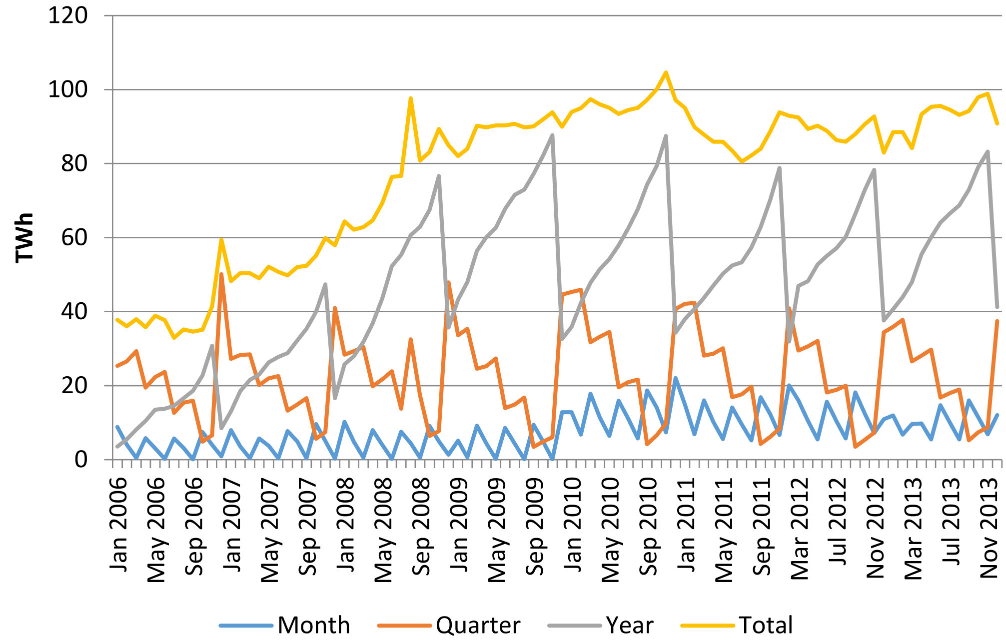

Figure 5: Open interest in EPAD contracts (end-of-month in TWh), break-down by maturity (*1,5 Column Figure)*
Note: Data for January and February 2012 are excluded due to data quality issue. (Data source: Nasdaq OMX)

Figure 6 breaks-down the development of open interest in EPAD by price areas. As of 2013, the price areas with the largest open interest in EPAD are Stockholm (SE3) and Helsinki (FI), taking approximately 46% and 33% of the total EPAD open interest, respectively.

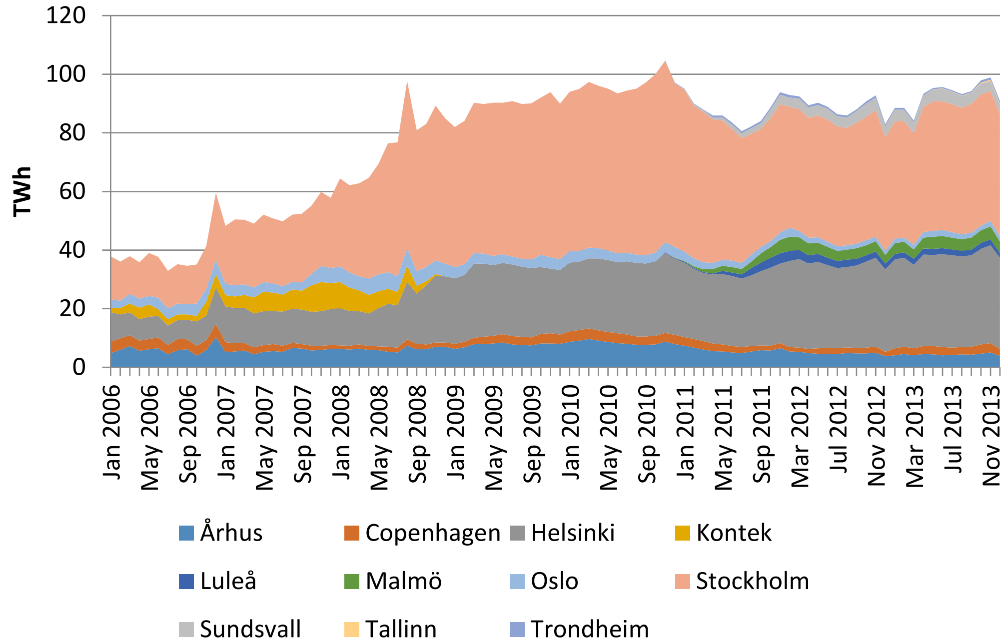

Figure 6: Open interest in EPAD contracts (end-of-month in TWh), break-down by price area (*1,5 Column Figure*)
Note: Data for January and February 2012 are excluded due to data quality issue. (Data source: Nasdaq OMX)

The total open interest on the Nordic financial electricity market exceeded 300 TWh in 2009 (NordReg, 2010, p. 25), from which EPAD took approximately 30% share. The EPAD contracts offer hedging against the price difference between the system price and the area price, which requires an estimate of the two underlying prices. Separate forward contracts do not require understanding of both the system-wide and local price dynamics and thus appear more flexible.

5.3 Relationship of forward risk premia and time-to-maturity

Prior research finds a negative relationship between time-to-maturity and forward risk premia (Benth, Cartea, and Kiesel, 2008; Marckhoff and Wimschulte, 2009). Time-to-maturity is calculated as the difference in calendar days between the trading day *t* and the first day of the delivery period for the respective contract. We test this relationship by regressing risk premia π_t^{EPAD} on their respective remaining time-to-maturity τ_t during the period 2001 - 2013.

$$\pi_{t,a}^{EPAD} = c + \beta\tau_t + \epsilon_t \qquad (5)$$

Where π_t, a = risk premium at time *t* in bidding area *a*

τ_t = remaining time-to-maturity

c = constant

ε_t = error term

Table 3 shows that most of the constants are statistically significant and positive. In other words, the average risk premium at the expiration date is above zero and statistically significant. However, many coefficients on the time-to-maturity variable are insignificant (at least one coefficient for each price area except SE3 Stockholm). The explanatory power of the regression as measured by the adjusted R^2 varies considerably, and can be high or low irrespective of the significance level of the constant or the beta coefficient.

Table 3. Regression results of the risk premium on time-to-maturity (2001-2013)

Area	Contract	N	c	beta	Adj. R^2
Åarhus (DK1)	Season	278	-0.2080	0.0061***	.0819
	Month	67	1.9482***	-0.0159	.0053
	Quarter	284	2.4278***	0.0035**	.0318
	Year	1081	2.2301***	0.0058***	.4998
Copenhagen (DK2)	Season	278	0.4115***	-0.0055***	.115
	Month	67	1.1235***	0.0046	-.0015
	Quarter	284	2.0321***	-0.0011	.0106
	Year	1081	1.5524***	0.0031***	.3762
Helsinki (FI)	Season	278	0.6231***	0.0011***	.0409
	Month	122	0.5079***	-0.0089***	.0985
	Quarter	301	-0.2730**	-0.001	.0075
	Year	1081	-0.2450***	-0.0024***	.7264
Luleå (SE1)	Season	--	--	--	--
	Month	122	0.2747**	-0.0153***	.3208
	Quarter	297	-0.4107***	-0.0018***	.1268
	Year	649	-0.6955***	-0.0016***	.6591
Malmö (SE4)	Season	--	--	--	--
	Month	122	4.1541***	-0.0327***	.443
	Quarter	299	3.7564***	0.0020**	.023
	Year	649	5.1647***	-0.0002	-.0002
Oslo (NO1)	Season	278	0.0286**	-0.0005***	.1677
	Month	67	0.1567	0.0035	-.0006
	Quarter	284	0.3056***	0.0025***	.1822
	Year	1081	0.7380***	-0.0005***	.0984
Stockholm (SE/SE3)	Season	278	0.4848***	0.0003*	.0191
	Month	122	0.7610***	-0.0138***	.2977
	Quarter	301	-0.0182	-0.0028***	.1423
	Year	1081	-0.3582***	-0.0008***	.16
Sundsvall (SE2)	Season	--	--	--	--
	Month	122	0.3492**	-0.0160***	.3332
	Quarter	297	-0.3661***	-0.0015***	.0933
	Year	649	-0.4009***	-0.0020***	.6185
Tallinn (EE)	Season	--	--	--	--
	Month	65	0.417	-0.0686	.0865
	Quarter	210	-3.1984***	0.0039*	.0321

	Year	20	0.4481	-0.0444***	.4415
Tromsø (NO3/NO4)	Season	--	--	--	--
	Month	67	-0.0134	-0.0052	.0634
	Quarter	279	-0.2908***	-0.0012***	.1552
	Year	649	-0.5756***	0.0002***	.0148

Note: This table shows the results of the regression of daily ex-post risk premia on time-to-maturity; *N* is the number of observations, *c* is the constant, and *beta* is the coefficient for the time-to-maturity variable; ***, **, * indicate statistical significance at 1%, 5%, and 10% levels; there are more yearly

Figure 7 plots the relationship between the average forward risk premia and the time-to-maturity for monthly EPAD contracts for the bidding areas Åahus (DK1), Copenhagen (DK2), Helsinki (FI), and Stockholm (SE3)[9]. Typical yearly, quarterly, and monthly EPAD are traded approximately three years, three quarters, and three months prior to maturity, respectively. We zoom closer into the final 60-day trading period prior to the contracts' maturity and highlight the following two observations. First, Helsinki and Stockholm bidding areas do follow Benth's et al. (2008) theory, which predicts a decreasing market risk premium with increasing time-to-maturity. This holds true for all the contract maturities in the two bidding areas. The risk premia initially display negative values, which implies that producers' hedging needs are stronger than the hedging needs of consumers. This relationship shifts approximately 30 days prior to maturity, when the risk premia start to display positive values and (on average) stay that way until the maturity.

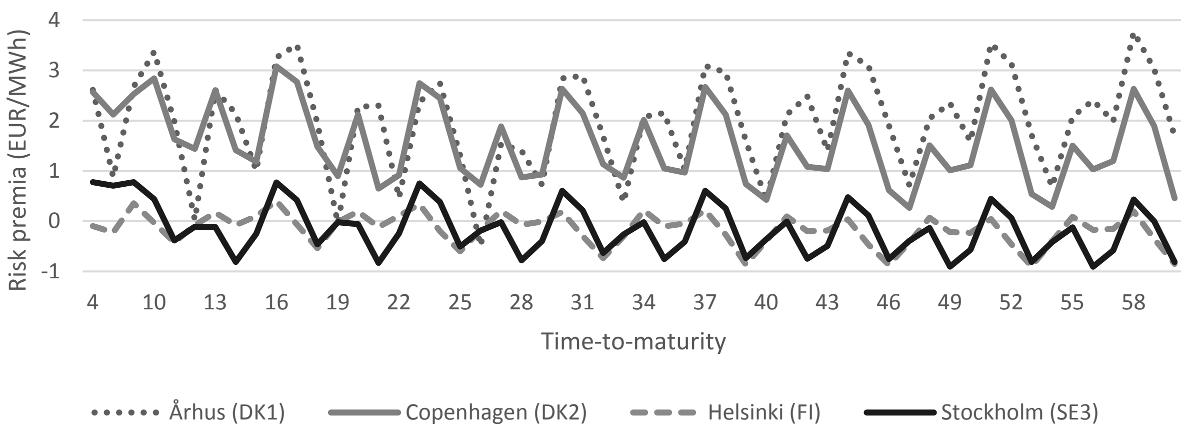

Figure 7: Average risk premia and time-to-maturity for monthly EPAD contracts with delivery between 2006-2013 for bidding areas Åahus (DK1), Copenhagen (DK2), Helsinki (FI), and Stockholm (SE3) *(Double Column Figure)*

The second observation relates to the data from Copenhagen (DK2) and Århus (DK1). As Figure 7 shows, the risk premia in DK1 and DK2, on average, never display a negative value, which is also true for the remaining contract maturities. The persistently positive risk premia in EPAD in the two bidding areas imply that the hedging needs of consumers always outweigh the hedging needs of the producers. This result is not predicted by the risk premia theory as discussed, which suggests shifting of the hedging pressures from consumers to producers as the time-to-maturity decreases. Therefore, in addition to time-to-maturity, market power, and market price of risk, additional factors appear to impact the behaviour of risk premia during the trading interval. In the case of Denmark, one third of electricity supply originates from wind power, which leads to high volatility in electricity supply and electricity prices. On account of the difficulty in predicting wind-power production, the area spot prices in Århus and Copenhagen are the most volatile from all the studied bidding areas, having a mean standard deviation of 17.2 and 19.6 during the studied 2001-2013 period, respectively. This production risk seems to be priced in the Danish EPAD contracts, allowing producers to systematically exert pressure on consumers and thus maintain positive risk premia over the trading period.

6. Conclusions and policy implications

In the increasingly intertwined European electricity markets, coherent understanding of the transmission risk hedging tools is essential for achieving greater market efficiency. This study synthesized the theory and practice behind the current long-term transmission rights in the Nordic electricity market. Together, financial transmission rights (FTR) and electricity price area differentials (EPAD) represent the main tools market participants use against the uncertainty of the locational electricity spot prices in day-ahead markets. In order to develop a common theoretical and practical understanding, this study has opened up the mechanics behind EPAD and exhibited examples of market results for hedgers and speculators on illustrative cases. The study touched upon the liquidity problem of EPAD, recognising that we cannot identify whether it is a supply or demand problem. However, the apparent solutions to improve EPAD liquidity reside in the education of market participants about the product's benefits, and reduction of transaction costs, fees, and market complexity. In particular, the regulatory burden presents a formidable entry barrier for a market newcomer, who must comprehend and comply with a multitude of regulations, such as REMIT, EMIR, EMIR II, MIFID, MIFID II, MIFIR, MAD, and MAR.

Identifying the theoretical and empirical gaps, we focused specifically on the forward risk premia, which we defined as a systematic difference between today's forward price and the future spot price expected at delivery, as revealed ex post. The importance of forward risk premia stems from implications for the underlying behaviour of market participants, who express their willingness to accept discounts or pay premia for reducing risk during different trading periods. Forward risk premia have direct impacts on hedging costs and reveal information on the dominant side of the hedging pressure, either suppliers or consumers. This research has brought new empirical evidence on the significance, direction, and magnitude of forward risk premia in EPAD for five Nordic and Baltic countries over the period 2001-2013. The longitudinal nature of this research provided empirical validation for previous studies, which defined characteristics of forward risk premia on more limited geographical and time samples. Additionally, our methodology improves forecast precision by utilizing daily frequency data, in comparison to earlier studies that relied on monthly averages.

We found only a partial support for the forward risk premium theory, which predicts a negative relationship between forward risk premia and time-to-maturity in electricity markets. General support for the theory is refuted by the findings for the case of Denmark, where systematically positive forward risk premia were observed over the trading periods of all EPAD maturities. This finding presents the need for further theoretical research on forward risk premia by expanding the considered factors beyond market power and market price of risk to consider supply risks. With the rapid growth of renewable resources in national energy portfolios, the security and reliability of supply will be increasingly relevant in the derivatives markets. Given the 20-25 year construction time of new cross-border interconnectors, policymakers should also be aware of the impact of construction delays on hedging costs in the electricity sector.

We acknowledge that our assessment of forward risk premia in EPAD may be specific to the Nordic electricity market. Nonetheless, EPAD is still one of the two main long-term transmission right mechanisms developed in electricity markets globally. Learning from the price dynamics, market design issues, and limitations of EPAD is essential to improving the efficiency of the European and international electricity markets. However, the ex-post methodology, which assumes perfect information and foresight, has theoretical and practical limitations, so alternative approaches for capturing forward risk premia should be contemplated.

Further research should transparently scrutinize the benefits and limitations of FTR and EPAD, ascertain whether they are substitute or complementary products, and quantify the impact of their deployment on key stakeholders. The effect of using the official daily fix vs. the actual last trade of the day on the analytical results on risk premia is another interesting future research avenue. Finally, market power in derivatives markets should be scrutinized by asking, for instance, whether power generators can increase spot-price volatility and thus command a higher forward risk premia.

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Footnotes

1

The standardized skewness coefficient is calculated as the skewness divided by the standard deviation of spot power prices cubed.

2

EPAD contracts were originally called contracts for differences (CfD) in the Nordic electricity market setting.

3

The theory of storage studies the difference between today’s spot and futures prices while considering the interest rate (interest forgone), storage costs, and convenience yield (Kaldor, 1939; Working, 1948).

4
Other studies measure forward risk premia between day-ahead (DA) markets (t-1) and real time (RT) markets (t), as a percentage change (DA-RT)/RT, see (Shawky, Marathe, and Barrett, 2003, p. 173). Alternative methodology for estimating ex-ante risk premia is developed by (Fleten, Hagen, Nygård, Smith-Sivertsen, and Sollie, 2015)
5
This illustration omits the expiry market settlement and instead focuses on the spot reference settlement for each hour of a single day. For contract and settlement details, see Nasdaq OMX Commodities (2014).
6
For detailed values of each step and formulas, see the Appendix.
7
The value of 3.45 EUR/MWh is the final closing price on 28.12.2009 used for the expiry market settlement calculation.
8
Contract 'Winter 1' covered the four months from January through April; contract 'Summer' covered the five months from May through September, and contract 'Winter 2' covered the three months from October through December.
9
We also plotted the negative relationship of forward risk premia and time-to-maturity for the remaining two contract maturities (quarterly and monthly) with identical results. We do not duplicate the same results here for the sake of conciseness. The results are available upon request from the corresponding author.

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Appendix

Table 1 Formulas applied in the illustrative scenario

Period	Variable	Formula
T-2	Futures system price	$F_{t,T}$
T-2	EPAD closing price	$EPAD_{t,T}$
T-1	Average area price during delivery	$\frac{\sum_{h=T_1}^{T_2}(P_h^{Area})}{T_2 - T_1}$
T-1	Average system price during delivery	$\frac{\sum_{h=T_1}^{T_2}(P_h^{System})}{T_2 - T_1}$
T-1	Price difference in production/consumption area	$\frac{1}{T_2 - T_1}\sum_{h=T_1}^{T_2}(P_h^{Area} - P_h^{System})$
T	EPAD profit & loss	$EPAD_{t,T} - (\frac{1}{T_2-T_1}\sum_{h=T_1}^{T_2}(P_h^{Area} - P_h^{System}))$
T	System futures profit & loss	$F_{t,T} - \frac{\sum_{h=T_1}^{T_2}(P_h^{System})}{T_2 - T_1}$

Table 2 Market outcomes for generators selling system futures and selling EPAD in production location

Period	Action: Sell futures, sell EPAD	Abbrev.	FI	SE3	NO1
T-2	System futures price, sell	FutSell	34.50	34.50	34.50
T-2	EPAD closing price in production location, sell	sellEPADpl	9.90	1.50	-2.50
T-1	Average area price during delivery	APto	42.02	36.19	29.62
T-1	Average system price during delivery	SYS	32.75	32.75	32.75
T-1	Price difference in production location (APpl - SYS)	PDpl	9.27	3.44	-3.13
T	EPAD profit & loss	EPADdiff	0.63	-1.94	0.63
T	System futures profit & loss	FutDiff	1.75	1.75	1.75
T	**Total Profit & loss**	**P&L**	**2.38**	**-0.19**	**2.38**
Profit		(FutSell - SYS) + (sellEPADpl – PDpl) > 0			
Loss		(FutSell - SYS) + (sellEPADpl – PDpl) < 0			

Note: Theoretical cash flow, calculated ex-post, from trading 1MW in three selected bidding areas during a sample day 14/8/2014.

Table 3 Market outcomes for retailers buying system futures and buying EPAD in consumption location

Period	Action: Buy system futures, buy EPAD	Abbrev.	FI	SE3	NO1
T-2	System futures price, buy	FutBuy	34.50	34.50	34.50
T-2	EPAD closing price in consumption location, buy	buyEPADcl	9.90	1.50	-2.50
T-1	Avg. area price during delivery	APcl	42.02	36.19	29.62
T-1	Avg. system price during delivery	SYS	32.75	32.75	32.75
T-1	Price difference in consumption location (APcl - SYS)	PDcl	9.27	3.44	-3.13
T	EPAD profit & loss	EPADdiff	-0.63	1.94	-0.63
T	System futures profit & loss	FutDiff	-1.75	-1.75	-1.75
T	**Total Profit & loss**	**P&L**	**-2.38**	**0.19**	**-2.38**
Profit		(SYS - FutBuy) + (PDcl - buyEPADcl) > 0			
Loss		(SYS - FutBuy) + (PDcl - buyEPADcl) < 0			

Note: Theoretical cash flow, calculated ex-post, from trading 1MW in three selected bidding areas during a sample day 14/8/2014.

Table 4 Market outcomes for traders (speculators) selling EPAD in trade origin and buying EPAD in trade destination

Period	**Action: sell EPAD in trade origin, buy EPAD in trade destination**	**Abbrev.**	**FI>SE3**	**SE3>FI**	**SE3>NO1**	**NO1>SE3**
T-2	EPAD closing price in trade origin (TO), sell	sellEPADto	9,90	1,50	1,50	-2,50
T-2	EPAD closing price in trade destination (TD), buy	buyEPADtd	1,50	9,90	-2,50	1,50
T-1	Avg. area price TO during delivery	APto	42,02	36,19	36,19	29,62
T-1	Avg. area price TD during delivery	APtd	36,19	42,02	29,62	36,19
T-1	Avg. system price during delivery	SYS	32,75	32,75	32,75	32,75
T-1	Price Difference in TO (APto-SYS)	PDto	9,27	3,44	3,44	-3,13
T-1	Price Difference in TD (APtd-SYS)	PDtd	3,44	9,27	-3,13	3,44
T	EPAD, TO, profit & loss	EPADto	0,63	-1,94	-1,94	0,63
T	EPAD, TD, profit & loss	EPADtd	1,94	-0,63	-0,63	1,94
T	**T, EPAD profit & loss**	**EPADdiff**	**2,57**	**-2,57**	**-2,57**	**2,57**
Profit		(sellEPADto – PDto) + (PDtd – buyEPADtd) > 0 => EPADto + EPADtd > 0				
Loss		(sellEPADto – PDto) + (PDtd – buyEPADtd) < 0 => EPADto+EPADtd < 0				

Note: Theoretical cash flow, calculated ex-post, from trading 1MW in three selected bidding areas during a sample day 14/8/2014.