Evaluating Hedging Possibilities on NordLink, NorNed and North Sea Link

Thema Consulting Group
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Abstract: This study is commissioned by NVE-RME to examine the implications of issuing long-term transmission rights on the NordLink, NorNed and North Sea Link cables. The report is intended to support NVE-RMEs consideration of whether long-term transmission rights should be issued for the three interconnectors.

Key words: FCA, Forward Capacity Allocation, LTTR, transmission rights, financial energy trading
Preface

The Norwegian Energy Regulatory Authority (NVE-RME) has hired Thema Consulting Group to investigate the implications of issuing long-term transmission rights on the NordLink, NorNed and North Sea Link cables.

As the Forward Capacity Allocation Guideline (FCA GL) will be implemented in Norway, the Norwegian Energy Regulatory Authority (NVE-RME) is preparing its investigations of the efficiency of the hedging opportunities for market participants in the energy market. The FCA GL aims at ensuring effective long-term cross-zonal trade with long-term cross-zonal hedging opportunities for market participants. If the cross-zonal hedging opportunities are not sufficient, it requires implementation of measures.

For NVE-RME the report will be used as input and background for the analysis which will be done in relation to the considerations whether the hedging opportunities are sufficient according to the FCA.

This study is commissioned by the Norwegian Energy Regulatory Authority and is conducted by Thema Consulting Group. The findings, analysis and recommendations of this report are those of Thema Consulting Group and do not necessarily reflect the official position of the Norwegian Energy Regulatory Authority.

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This document is sent without signature. The content is approved according to internal routines.
Evaluating Hedging Possibilities on NordLink, NorNed and North Sea Link

Commissioned by RME-NVE
May 2021

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Brief summary

This report examines the implications of issuing long-term transmission rights on the NordLink, NorNed and North Sea Link cables. These cables will connect the Norwegian power market with the power markets of Germany, the Netherlands and Great Britain respectively. The Forward Capacity Allocation Guideline (FCA GL) proposes that long-term transmission rights be issued on all bidding zone borders and, where this is not done, requires that National Regulatory Authorities regularly review cross-border hedging opportunities. This report is intended to support RME’s consideration of whether long-term transmission rights should be issued for each of the cables noted above.

The report covers the economic importance of hedging, current opportunities to hedge power price risk in the affected markets, the potential role of transmission rights, the sufficiency of current hedging opportunities in Norway, the implications of alternative transmission right product designs and the costs and benefits of issuing rights on these specific cables.

We conclude that transmission rights have the potential to improve hedging opportunities, notably by increasing the liquidity of futures in the associated markets, but that, without mitigating measures, issuing such rights could have potentially significant impacts on cable revenues and therefore Norwegian consumer tariffs.

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THEMA Consulting Group is a Norwegian consulting firm focused on Nordic and European energy issues, and specialising in market analysis, market design and business strategy.

Disclaimer

Unless stated otherwise, the findings, analysis and recommendations in this report are based on publicly available information and commercial reports. Certain statements in this report may be statements of future expectations and other forward-looking statements that are based on THEMA Consulting Group AS (THEMA) its current view, modelling and assumptions and involve known and unknown risks and uncertainties that could cause actual results, performance or events to differ materially from those expressed or implied in such statements. THEMA does not accept any liability for any omission or misstatement arising from public information or information provided by the Client. Every action undertaken on the basis of this report is made at own risk. The Client retains the right to use the information in this report in its operations, in accordance with the terms and conditions set out in terms of engagement or contract related to this report. THEMA assumes no responsibility for any losses suffered by the Client or any third party as a result of this report, or any draft report, distributed, reproduced or otherwise used in violation of the provisions of our involvement with the Client. THEMA expressly disclaims any liability whatsoever to any third party. THEMA makes no representation or warranty (express or implied) to any third party in relation to this report. Any release of this report to the public shall not constitute any permission, waiver or consent from THEMA for any third party to rely on this document.
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1 INTRODUCTION

The European power market is governed by several elements of European regulation including the Guideline on Forward Capacity Allocation, or FCA GL. Among other things, this guideline seeks to ensure that market participants have sufficient opportunities to hedge cross-zonal power price risk. To this end, Article 30 of the FCA GL establishes the principle that, by default, TSOs should issue long-term transmission rights for the bidding zone borders for which they have responsibility. These rights offer a mechanism by which market participants can hedge the cross-zonal price spread. Article 30 of the FCA GL also sets out a process by which National Regulatory Authorities may choose not to follow these default market arrangements.

The FCA GL is applicable to EEA members and, though not currently in force in Norway, is expected to be implemented via the EEA Agreement. As such, NVE-RME, as Norway’s National Regulatory Authority, will need to consider whether long-term transmission rights should be issued on cross-zonal borders consistent with its obligations under the FCA GL.

This report looks specifically at the implications of issuing long-term transmission rights on the NordLink, NorNed and North Sea Link interconnectors. These interconnectors will form the cross-zonal connections between the Norwegian NO2 bidding zone and the bidding zones of Germany, the Netherlands and Great Britain respectively. These connections also represent all of Norway’s connections to non-Nordic bidding zones.

The report is structured as follows:

▪ Section 2 describes the economic implications of a lack of opportunities to hedge power price risk.
▪ Section 3 provides an overview of how power price hedging is currently conducted in Norway, Germany, the Netherlands and Great Britain and the set of products used to do so.
▪ Section 4 explains how transmission rights could potentially be used.
▪ Section 5 explores evidence on the sufficiency of current hedging opportunities by looking both at the NordREG metrics on the Nordic forward market, as well as stakeholders’ stated opinions on current opportunities to hedge power price risk and the potential impacts of issuing transmission rights.
▪ Section 6 explores different types of transmission rights and the implications of different design choices.
▪ Section 7 sets out the costs, benefits and distributional implications of issuing transmission rights and concludes.

As part of the work, we have calculated several metrics related to the liquidity of the Nordic forward market, as set out in NordREG’s ‘Methodology for assessment of the Nordic forward market’. We have also sought to provide some relevant comparators covering the German, Dutch and British markets. These metrics are presented as an appendix to the report.

1 Commission Regulation (EU) 2016/1719 of 26 September 2016 establishing a guideline on forward capacity allocation
2 THE ECONOMIC IMPORTANCE OF OPPORTUNITIES TO HEDGE POWER PRICE RISK

In this section we briefly set out:

- The economic rationale for hedging, and
- The economic benefits of access to liquid, transparent products for the hedging of power price risk.

2.1 The economic rationale for hedging

Hedging is ultimately about risk management. Our desire to manage risk stems both from the fact that extreme outcomes can add directly to economic costs, for example the cost of having to liquidate a bankrupt firm, and the fact that individuals are often themselves risk-averse, preferring a predictable outcome to a lottery of famine or feast. By managing risks effectively, we can therefore avoid the economic costs of extremes and give risk-averse individuals the certainty they desire.

Hedging products allow risks to be transferred between participants. They potentially enable these risks to be offset, as is possible when parties have opposing exposures to a price, or at least shared among a broad base, hopefully avoiding extreme outcomes for any individual. Hedging strategies also take a number of forms including co-ownership, the use of bilateral contracts and the trading of financial derivatives.

Uncertainty as to the future power price means that market participants that are exposed to the future power price are exposed to some risk. This is true whether you are an electricity retailer agreeing to supply a fixed-price contract or an investor committing capital to a generation project. In both cases, these participants’ desire to manage the risks that they face may encourage them to hedge this power price risk.

2.2 The economic benefits of access to liquid, transparent hedging products

Hedging activity results in some direct economic costs. Trading systems need to be established and operated and this involves the use of capital, for example IT infrastructure, and labour, as individuals spend time hedging risk on behalf of their organisations. Liquid and transparent hedging products can help to keep these costs to a minimum while also supporting a number of economic benefits.

When hedging products are illiquid, this tends to increase the direct costs associated with hedging activity. The holders of illiquid products run the risk that they will not be able to alter their positions quickly, or only be able to do so at high cost. As such, this risk is factored into the price at which they are willing to transact and illiquid products therefore have large bid-ask spreads that must be paid in order to trade. Market participants without access to liquid hedging products may also consider a wider variety of approaches to hedging, such as bilateral contracting, and therefore need to invest time and effort into seeking out counterparties and negotiating non-standardised terms. All of this adds directly to the economic costs of hedging.

These higher hedging costs are not only a cost in their own right, but can also harm economic welfare by:

- Limiting investment in higher-risk, higher-return projects, and
- Weakening competitive pressure in sectors exposed to power price risk.

Let us consider the likely impact on investment first. Investment generally entails some risk and an inability to cost-effectively manage these risks may prevent higher-risk, higher-return investments from occurring. Consider the developer of a wind power project with a lifetime of 15-20 years looking for capital to fund the project. Let us assume that the project is highly profitable according to current costs and power price expectations but that the future power price is uncertain and may be much lower than expected. Both the developer and prospective investors will consider potential risks before they decide to invest. The greater the downside risk, the greater costs of capital required to attract investment. If the risk is high enough, the project will not be commercially viable.
Ideally, hedging will enable the project developer to manage these risks and facilitate investments in projects that, as a group, have higher economic returns. For example, assuming a suitable market were available, the developer might sell the expected generation from the project now using a futures contract. In doing so, an uncertain future price could be replaced by a known price, reducing uncertainty over the project’s future revenues and helping to ensure that the project is actually realised.

On the impact of hedging on competition, it is important to realise that a lack of liquid hedging opportunities may help to protect firms from competition. Competition is supported, in part, by the threat of new entry into the relevant market. Incumbent firms know that if they seek to exploit their customers, new firms may enter the market and replace them. The higher the costs faced by a new firm seeking to enter a market, the weaker the threat facing incumbent firms. In some markets, high-cost hedging can add directly to these costs and thereby potentially weaken competition.

Most obviously, if the lack of hedging opportunities provides strong incentives for firms to integrate generation and power use or supply into a single company to help manage power price risk, so-called vertical integration, this can be a barrier to entry. It implies the need to form an integrated business to enter the market. A standard example of this would be the integration of a local generation and supply company, where the supply company offers fixed-price contracts and manages this resultant risk internally thanks to its generation portfolio. If we consider the retail market for fixed price supply contracts, the lack of low-cost hedging opportunities means that a new entrant cannot manage the power price risk associated with selling fixed price contracts. To do so, the prospective entrant would have to enter not just as a supply company, but as a vertically-integrated generation and retail business. This adds significantly to the implied costs of new entry into the retail market and potentially dampens competition in that market.

Finally, and in addition to the benefits linked to lower cost hedging noted above, transparency in the pricing of hedging products can support economic efficiency more broadly by allowing the valuable information contained in prices to inform decision-making elsewhere in the economy. The price for hedging products contains information on market participants’ future price expectations. Economic actors taking decisions that depend on future price expectations can use this information to improve the decisions they take. So, whether an actor is trying to decide when to retire a generation plant or how to price an energy-intensive manufacturing job with a future delivery date, these decisions can benefit from the input of all the actors operating in the hedging market. Indeed, even regulatory decisions on the competitiveness of the retail energy market can benefit from transparency over the market’s future price expectations.

In summary, liquid and transparent markets for hedging power price risk have several economic benefits. They reduce the direct costs of hedging activity and, in doing so, support both investment efficiency and competition in markets facing significant power price risk. They also enable valuable information about future price developments to be shared across the economy and thereby contribute to efficiency in general. Ultimately, all of these benefits contribute to higher economic welfare and to growth.

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3 Various research papers show the beneficial impact of financial markets on economic growth in developing economies.
3 HEDGING OPPORTUNITIES IN NO2, GREAT BRITAIN, THE NETHERLANDS AND GERMANY

In this section, we set out background information on the tools used to hedge power price risk in Norway, Great Britain, the Netherlands and Germany, as well as how approaches to hedging differ between these countries. We also provide some general discussion of typical approaches to hedging price risk and how these differ among market actors based on their hedging needs.

3.1 Hedging tools

Power price risk can be managed in a variety of ways and, in this section, we outline the main tools used by market actors for this purpose. For completeness, it should be noted that firms can also manage these risk exposures through the maintenance of greater capital reserves and vertical integration, namely the joint-ownership of both generation and consumption or supply businesses. In the latter case, the firm alters its structure to help ensure that price risk exposure is offset internally within its business. These approaches to risk management, though commonly observed, are not discussed further below, since they do not constitute what are typically thought of as hedging strategies.

3.1.1 Power futures

Futures contracts are standardised financial contracts for power that effectively allow market participants to lock in a price for power delivered in future periods. Financial futures contracts do not entail any physical power supply. Rather, during the delivery period specified by the contract, cash is exchanged between the market participant and the exchange such that these payments make up for any difference between the future contract’s price before delivery and the power price during the delivery period. Changes in the value of the futures contract between the time of a trade and delivery will also be settled between the exchange and the market party, with the timing of this settlement varying between different contract types.

In some markets, forwards offer participants a similar ability to fix prices ahead of delivery, but result in the physical delivery of power, rather than cash settlement.

In most Continental European power markets, power futures are referenced against the spot price of a specific bidding zone. In the Nordic market, such contracts a reference against the Nordic system price, rather than the price of a specific bidding zone. The system price is calculated as the clearing price that would obtain if clearing the entire Nordic region as a single bidding zone, ignoring transmission constraints between Nordic bidding zones.

Futures contracts can cover different length delivery periods and may also be profiled within that period, for example covering only certain peak settlement periods.

3.1.2 Electricity Price Area Differential (EPADs)

Since Nordic futures are referenced against the Nordic system price, they cannot be used directly to hedge the power price of a specific bidding zone. EPADs are similar financial contracts that reference the spread between a specific Nordic bidding zone and the system price. They are available as baseload contracts (i.e. with no profiling). Combining an EPAD for a specific bidding zone with a system-price future contract effectively produces a futures contract referenced to the specific area price. Combing the purchase of an EPAD for one zone with the offsetting sale of an EPAD in another zone produces a financial contract (a so-called EPAD Combo) that hedges the price between the two zones.

Exchange-traded EPADs do not exist for all Nordic bidding zones and do not currently cover NO2 and NO5, although over-the-counter (OTC) contracts may be available bilaterally.
3.1.3 Transmission rights
Transmission rights are contracts typically issued by transmission owners that provide the holder with a right or obligation to flow power in a specific direction between connected bidding zones. Such rights are typically issued as Financial Transmission Rights (FTRs) and are financial in the sense that the right is cash-settled based on the price spread between the relevant zones. An FTR option provides the holder with the price spread only where this spread is positive. An FTR obligation will result in a payment between the holder and issuer of the obligation that reflects the direction of the relevant price spread. For example, if the obligation involves flowing power from a low- to a high-price zone, the obligation will be profitable and result in a payment to the holder of the obligation. If, however, the obligation is from a high- to a low-price area, the obligation holder is liable to pay the spread to the issuer.

Such contracts can be used to hedge the price spread between connected zones directly. They can also allow market participants to hedge using futures (or other hedging instruments) referenced against power prices in the other bidding zone. In the latter case, the transmission rights allow the firm to manage the risk that the reference price differs from the power price to which they are exposed (so-called basis risk).

3.1.4 Power Purchase Agreements (PPAs)
Power Purchase Agreements are bilateral agreements for the sale of power. They typically cover periods of 5-15 years and are often, though not necessarily, physical contracts, resulting in the provision of power rather than cash settlement. As bespoke contracts, the specific terms can vary from contract to contract. Often the contract will specify the profile and volume of power to be delivered, the delivery location and the agreed price. The contract may also include covenants designed to ensure the credit-worthiness of the parties involved and may require that the counterparties have guarantees provided by banks or parent companies.

PPAs may be sold by specific generation projects or by utilities. In the latter case, the power is generally supplied by a portfolio of sites. Where power is sold by a variable generator, such as an onshore wind site, the volume of power sold under the PPA will often be 'shaped' or 'sleeved' by a third party that takes responsibility for correcting any mismatch between the generation project’s output and the volume of power that must be supplied under the PPA.

PPAs allow the parties involved to agree on the future price of power in advance and therefore reduce their exposure to changes in the spot price of power for the delivery period specified in the PPA.

3.1.5 Coal, gas and (carbon) emissions futures
A variety of other commodity futures exist and are used by some market actors in their power price hedging activity. These futures are similar to power futures, except that they reference the price of another traded commodity, such as coal, gas or emissions allowances. In bidding zones where the power price is strongly linked to the marginal costs of gas-fired generation, for example, there may be a strong correlation between power prices and gas prices. In this case, power prices could be hedged through the use of gas futures, with these futures acting as a proxy to hedge the actor’s fundamental power price risk exposure. Such hedges are so-called ‘proxy hedges’ and typically entail some degree of risk (so-called basis risk) due to a potential mismatch in changes between the actual price to which the actor is exposed (the power price) and the price referenced by the hedging instrument (the gas price). This risk may be justified, for example, because of the greater liquidity or lower costs associated with the use of proxy hedging instruments.

3.2 Differences in hedging between bidding zones

3.2.1 Norway
As noted above, the structure of Nordic financial hedging products differs from that in the other zones connected by the cables of interest in that power futures are not referenced against a bidding zone.
price. Instead, they are referenced against the Nordic system price. System price futures are used to hedge power price risk and the system price has historically been closely correlated with the prices in NO2. It should be noted, however, that increased interconnection capacity in NO2, as well as the deployment of additional offshore wind capacity in the north of Norway may weaken this correlation going forward. Area price risk in NO2 can theoretically be managed through the use of EPAD contracts but, as noted previously, NO2 EPADs are not exchange-listed and so area price risk can only be hedged through a broker or bilateral contracting.

Transmission rights are not currently available for any Norwegian zones. However, proxy hedging of the NO2 price using German power price contracts is currently practised. This reflects the direct interrelationship of prices in Germany and southern Norway due to the interconnection of the markets. It may also be motivated by the comparatively high liquidity of German futures contracts.

Market actors also manage their risk through bilateral arrangements and via trading firms offering hedging services. Bilateral arrangements can include bilateral exchanges of standardised exchange contracts or variants of these that, for example, are linked directly to an area price or denominated in local currency. Smaller actors, in particular, may be able to hedge power through trading firms that, again, allow actors to hedge area price and currency risk.

PPAs are relatively common in the Nordic market, supported by considerable onshore wind development and project developers’ desire to enter into PPAs as a means of securing lower-cost project finance.

### 3.2.2 Great Britain

Although GB power futures are exchange traded, the British market is unusual among the markets considered in this project in that the overwhelming majority of electricity trading is performed over-the-counter rather than via one of the exchanges. Much of this trade is physical. In the first half of 2020, OTC trade represented more than 80% of trade in British power by volume.\(^4\) Much of this OTC trade is conducted through a common screen-based trading system via brokers.

The wholesale power market is also marked by several vertically integrated generator-supplier utilities that are naturally hedged to some extent due to their structure and that can hedge internally. Bilateral trades between these vertically integrated players also occur.

Due to the greater variation in power prices across the day relative to the Nordics, there is comparatively more trading of ‘peak’ products, referenced to a 12-hour peak on weekdays.

The nature of the British power system results is a relatively strong correlation between power and gas prices and gas futures are relatively liquid. As such, power price hedging using gas futures is not uncommon.

Transmission capacity on interconnectors between Great Britain and connected bidding zones is typically auctioned by the asset owner.

### 3.2.3 Germany

The German market benefits from a relatively liquid market for power futures, which attracts proxy hedging by actors in neighbouring markets. The churn ratio (volume of power trades / consumption) for Germany was 7.85 in 2019, significantly higher than the equivalent ratio of about 3 in Great Britain, which is the European market with the second-highest ratio. The equivalent Nordic ratio is around 2.\(^5\)

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\(^4\) Ofgem, Electricity trading volumes and churn ratio by month and platform (GB), [https://www.ofgem.gov.uk/data-portal/wholesale-market-indicators](https://www.ofgem.gov.uk/data-portal/wholesale-market-indicators)

\(^5\) ACER-CEER, Market Monitoring Report (MMR) 2019, Volume 1, Figure 16 [https://aegis.acer.europa.eu/chest/dataitems/196/view](https://aegis.acer.europa.eu/chest/dataitems/196/view)
The use of German power futures by actors in connected zones is also facilitated by the auctioning of transmission rights for interconnection capacity between German and neighbouring bidding zones.

OTC hedging is also commonplace for German power and accounts for roughly 60% of total traded volumes in 2019. Some of this OTC trade reflects the use of screen-based brokerage platforms provided by major utilities.

### 3.2.4 The Netherlands

Hedging in the Netherlands is similar to Germany but the market for Dutch power futures is less liquid. As such, some players choose to hedge Dutch power price exposures using German power futures, possibly supported by the use of FTR options on the relevant border. Given the relatively strong correlation between Dutch and German prices, and the resultant substitutability between German and Dutch futures, German future prices act as a useful reference for the pricing of Dutch hedging products. OTC hedging is similarly common in the Dutch market.

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6 ACER-CEER, Market Monitoring Report (MMR) 2019, Volume 1, Figure 16
https://aegis.acer.europa.eu/chest/dataitems/196/view

7 See, for example, RWE’s Easy Commodity Trader https://www.group.rwe/en/ect
4 THE POTENTIAL ROLE OF TRANSMISSION RIGHTS

In this chapter, we discuss the potential role of transmission rights in meeting market participants’ needs. We detail the comprehensive set of theoretical uses for transmission rights and compare these possible use cases with our understanding of market participants hedging needs, as gained from interviewing market participants.

4.1 The potential uses of transmission rights

In the European regulatory model, private transmission rights are more appropriately thought of as the right to the income generated from the use of transmission capacity to arbitrage interconnected power markets. They do not allow the owners of the rights to do what they want with the associated capacity. Rather the actual use of the capacity is determined by regulation intended to ensure the efficient operation of the internal energy market.

The income provided by a right is uncertain and primarily reflects the price spread between the two interconnected markets. Purchasing this stream of income can be useful to market participants as a means of hedging exposure that market participants have to the power prices in these markets.

In general, there are two potential uses of transmission rights, discussed further below. Transmission rights can either be used to hedge:

1. A direct exposure to the price spread across the relevant cable, or
2. An exposure to prices in one market using hedging products referenced against prices in the other market.

If an organisation is directly exposed to the price spread between two zones, purchasing transmission rights can potentially be used to create an offsetting exposure and therefore hedge this risk. We discuss the potential cases in which organisations might have a direct exposure to the price spread on the next section.

The second case is perhaps less intuitive, but no less important. Consider a company that wishes to buy forward power for the next calendar year. This company is located in NO2 and therefore wishes to hedge the NO2 price. It could potentially do this, at least theoretically, by buying power in the German market (e.g. using a German futures contract) and buying a transmission right to flow this power from Germany to NO2. In this way, the company hedges a power price exposure in one bidding zone (NO2) using hedging products referenced against another price zone (Germany). Using hedging products referenced against power prices in other zones may be preferable if these hedging products are cheaper or more liquid than those referenced against the power price to an organisation is actually exposed. As a result, the use of transmission rights to support hedging using hedging products in connected zones is sometimes referred to as providing a ‘bridge to liquidity’, since the transmission rights facilitate access to more liquid hedging markets. We discuss the relevance of this case further below.

4.2 Hedging exposure to the cross-zonal spread

There are a variety of ways in which market participants may be directly exposed to the price spread between two markets. In this section, we set out the possibilities and consider to what extent they are likely to be relevant for the cables under consideration.

We consider the following categories of market participants:

- Generators/retailers
- Consumers
- TSOs
- Independent interconnector owners

For simplicity, we refer to two markets, one domestic and one foreign, and consider the hedging needs of the domestic market participants.
4.2.1 Generators/retailers

For a generator, a direct exposure to the price spread across a cable can arise in two situations:

1. The generator in the domestic market has agreed to sell power in the foreign market, or
2. The generator in the domestic market is itself a consumer in the foreign market.

To see how these setups result in an exposure to the power price spread, we can consider each price exposure individually.

In the first instance, the generator receives the contract price, \( P_c \), in the foreign market. The power generated is fed into the domestic grid at a price, \( P_d \). To deliver to the foreign customer, the generator will ultimately have to buy power, at \( P_f \), in the foreign market. The total payoff for the generator is therefore \( P_d + P_c - P_f \) or \( P_c - (P_f - P_d) \). \( P_d - P_f \) is the price differential between the two markets and the price spread across a cable connecting these two markets. This creates a hedging need if the generator wishes to fully secure its sales revenues.

We can make an analogous argument for a generator in the domestic market who is also a consumer in the foreign market. Again, this organisation will be selling in the domestic market and buying in the foreign market. Even if the volume of generation and consumption match exactly, this organisation will still be exposed to the difference in price between the two bidding zones.

4.2.2 Consumers

For consumers, we can consider the case of an end-user in the domestic market that has a long-term supply contract with a point of supply defined as being within the foreign bidding zone. The consumer agrees to pay a fixed price of \( P_c \) for power delivered in the foreign market. However, as the generator/supplier is located in a different bidding zone, the consumer must still purchase physical power in the domestic market at a price \( P_d \). These purchases can be funded by the sale of the power received in the foreign market at \( P_f \). However, since the consumer must buy power domestically and sell it in the foreign market, this setup will leave the consumer exposed to the price spread between the relevant bidding zones.

4.2.3 TSOs

A regulated TSO which can add the costs of an interconnector to the regulatory cost base and offset any congestion income against tariffs is not exposed to cross-border price risks. This regulatory setup ensures that TSO income is independent of power market prices.

However, if the TSO is not able to offset congestion income against tariffs under its national regulatory model, the TSO will be exposed to price differences between the domestic and the foreign market. In this case, cross-border hedging might be helpful as a means to reduce this risk.

Statnett, TenneT NL and TenneT DE all operate under regulatory frameworks designed to ensure that they are not financially exposed to congestion income. All TSOs in EU member states are bound by the restrictions on the use of congestion income set out in Article 19 of Commission Regulation 2019/943. Put simply, this article requires that congestion income must be used to maintain or expand cross-zonal capacity or else offset against revenues from network tariffs. The intent of this regulation is to ensure that TSOs have no financial incentive to increase congestion revenues.

National Grid’s system operation functions and interconnector ownership are contained in two distinct legal entities with a common owner. The functions are covered by two distinct license types, such that the system operator does not have any direct ownership of interconnection assets. As such, National Grid’s ownership arrangements are more akin to that of an independent interconnector owner, as discussed below.

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8 The BritNed cable has a regulatory exemption.
4.2.4 Independent interconnector owners

An independent interconnector owner will typically earn income from congestion between the two markets. As a result, it may be directly exposed to the price spread across the cable and potentially interested in hedging this exposure through the sale of transmission rights.

National Grid operates effectively as a merchant interconnector owner through National Grid Ventures and can benefit financially from higher auction revenues from the sale of transmission capacity. Interconnectors like the North Sea Link are covered by Great Britain’s cap and floor regime, which establishes a cap and floor on interconnector owners’ profits. Beyond these thresholds, the interconnector owner’s return is set by regulation and therefore the link between congestion revenues and profits is broken.

4.2.5 Relevance to NordLink, NorNed and North Sea Link

Although there exist several theoretical circumstances in which organisations might be directly exposed to the cross-zonal price spread, as detailed above, we do not believe that there are any significant examples of these circumstances holding for NordLink, NorNed and North Sea Link cables. This finding echoes the conclusions of an earlier study considering the potential use of transmission rights on NordLink specifically.\(^9\) We are also sceptical that this situation is likely to change in the near future, even in the event that transmission rights are made available on the relevant cables.

First, it should be noted that the TSO and independent interconnector ownership cases discussed above are not applicable to these cables. All of them are joint projects in which Statnett is a co-owner and Statnett is regulated in such a way that it is not exposed to the congestion income on these cables. It therefore has no direct interest in hedging. More generally, European regulation on the use of congestion incomes\(^10\) is designed to ensure that TSOs do not benefit financially from congestion incomes and their financial performance is therefore generally independent of these revenues.

When it comes to the cases in which generators, retailers or consumers have opposing positions at either end of the cable, we have not been able to identify any actors for which this is the case. This is despite trying to reach out to any potentially relevant parties in all of the affected markets. Specifically, we contacted the relevant branch organisations in each of the markets to try and identify players that might have exposure in Norway and one of the foreign markets. From this search, we conclude that there are a relatively small number of companies that have physical exposures to both the NO2 price and prices in one of the interconnected markets and, in those cases where a company does have such exposures, these exposures are not opposing. Thus, for example, international generation majors may be net generators in multiple zones and international manufacturers may be net consumers in multiple zones. However, as far as we can tell, there are not examples of companies that are net generators in one of these zones and net sellers or consumers in another. As such, these companies are not exposed to the price spread.

Arguably, the absence of companies exposed to this price spread may be the result of the fact that, with the exception of NorNed, these cables are not operating or only have a short history of operation, and that transmission rights between the relevant zones do not currently exist. This means that managing the relevant price spread may be significant difficult to hedge, dissuading companies from taking such a position. However, among the market participants we spoke to directly, none of them seemed to think that greater interconnection between NO2 and neighbouring markets was likely to make opposing cross-border setups more likely. In addition, the branch organisations representing energy utilities in Great Britain, the Netherlands and Germany reported that their memberships showed relatively interest in the availability of such rights, also suggesting that they do not have strategic plans to take position that might result in exposures across these cables. Thus, while things may of course change, there do not appear to be any companies considering near-term changes in

their setup that would result in them being directly exposed to the price spread across the cables of interest.

4.3 Using transmission rights as a 'bridge to liquidity'

Potentially more relevant, therefore, is the idea that transmission rights might act as a bridge to liquidity. Indeed, our own discussions with stakeholders, as well as the results of previous work on hedging between Norway and the Netherlands, suggest that transmission rights on NordLink, NorNed and North Sea Link are far more likely to be used for this purpose than to hedge a direct exposure to the price spread on the cable.

The fundamental idea here is that when hedging a power price exposure, one is not restricted to using hedging products that refer to the exact price to which one is exposed. One can, for example, hedge exposure to a power price risk by taking positions in related commodities, like coal and carbon for example, that tend to oppose movements in your fundamental exposure. This is called proxy hedging, since it involves hedging using proxies for the price to which one is exposed. Proxy hedging can also involve constructing hedges using power price derivatives referenced against power prices in different bidding zones. Thus, if NO2 and German power prices are correlated, one could partly offset exposure to the NO2 price by taking an opposing position in the German power price. The closer the correlation, the better the hedge. Since the reference price for our hedging product may not always follow the price to which we are exposed, this hedge is imperfect and proxy hedging therefore leaves one exposed to a residual 'basis risk', namely the spread between these two prices.

Transmission rights offer one possible way to hedge this basis risk and therefore to complement a strategy of proxy hedging using hedging products referenced against prices in neighbouring zones. Taking our earlier example, let us imagine that I want to hedge future power prices in NO2. I could do this by combing a product that pays out the German power price, P_G, e.g. a German futures contract, and a product that pays out the difference between the German and NO2 prices, P_{NO2}-P_G, such as a transmission obligation from Germany to NO2. Combining these products results in a perfect hedge for the NO2 price. Stakeholders may be incentivised to hedge using products referenced against other bidding zones where these hedging products are less costly or more liquid than the hedging products that directly reference the power price to which they are exposed.

In the 2013 study on hedging between Norway and the Netherlands, none of the 15 market participants interviewed identified a physical need to hedge cross-border risk. However, two generators identified the need for transmission rights as a means to support hedging using products in the connected zone, along lines similar to those outlined above.

Similarly, in our own discussions with market participants, none of them could identify a need for transmission rights as a means to hedge a direct physical exposure to the cross-border price spread, but some did support the issuance of transmission rights as a means to facilitate hedging opportunities more generally. The supporters of issuing transmission rights included the European Federation of Energy Traders and the German and Dutch branch organisations for energy utilities (BDEW and Energie-Nederland). All of these organisations support the issuance of transmission rights on principle. There was also support for the issuance of transmission rights from those foreign energy companies that are already using transmission rights as part of a trading or hedging strategy, and from Norwegian actors providing power price hedging services. These actors cited the potential liquidity and competition benefits that transmission rights can bring, and which are discussed in further detail in section 7.1.1. Norwegian generation companies were more ambivalent to the introduction of transmission rights as a means to provide a bridge to liquidity and, specifically, wanted to ensure that these potential benefits did not come at the cost of reduced liquidity in existing Nordic hedging products. The liquidity impacts of transmission rights are discussed further in section 7.4.

4.4 Reflections on market participants’ existing hedging needs and approaches to hedging

The above sections set out how transmission rights can, in theory, help meet market participants’ hedging needs and conclude that such rights are likely to be most useful as a means to providing a
bridge to liquidity. In this section, we consider how this practice fits with market participants’ existing hedging needs and approaches to hedging.

There are three points worth covering in this regard:

1. The impact of administrative constraints on hedging behaviour,
2. The peculiarities of hedging product availability in NO2, and
3. The types of hedging products used by different market participants.

These insights into hedging behaviour among Nordic market participants are drawn from a study of approaches to hedging in the Norwegian Swedish and Danish markets conducted by THEMA on behalf of the respective national regulators. That study drew on the responses to a publicly accessible online questionnaire covering 59 market participants and 29 follow-up interviews.

### 4.4.1 The impact of administrative constraints

Market participants’ approach to hedging appears to be significantly affected by the administrative capacity of the organisation. Consumers and smaller actors will typically have fewer staff members responsible for power price hedging and less ability to pursue more complicated hedging strategies. These actors are often not engaged in the trading of existing Nordic financial derivatives and it therefore seems unlikely that they would use transmission rights.

In contrast, large generators are already relatively well-informed on market developments and may be able to conduct fundamental power market analysis independently. As such, they are more likely to trade directly on the exchange, to already engage in proxy hedging using power derivatives in other countries and to explore a variety of opportunities to construct a hedge. Given this, they are more likely to consider using a transmission right as part of a hedging strategy.

The nature of participants in existing transmission rights auctions across Europe suggest that these observations may also be true of hedging activity in Europe more generally, as energy majors with energy trading desks heavily represented among the lists of transmission-right-auction participants.

It is worth noting that, although smaller players are unlikely to engage in the use of transmission rights directly, that does not necessarily mean that they would be excluded from any reductions in hedging costs or improvements in hedging opportunities resulting from the use of transmission rights by larger or more sophisticated trading organisations. In particular, the study of Norway, Sweden and Denmark showed that banks, brokers and trading firms sometimes act as intermediaries and provide retail power price hedging services to smaller actors. These services are often offered alongside related services such as lines of credit or balancing management. In theory at least, any benefits that the use of transmission rights bring might therefore be made indirectly available to smaller market participants via such intermediaries.

### 4.4.2 The peculiarities of hedging product availability and hedging needs in NO2

All three cables under consideration have landing points in the NO2 bidding zone. At present, there is no exchange-traded EPAD for the NO2 bidding zone and therefore no exchange traded derivative referenced against the NO2 price. This may change in the future, and the issuing of transmission rights on these cables might even precipitate the creation of an exchange-traded NO2 product. However, given the current set of exchange-traded products available, it is more difficult to construct a proxy hedge using NO2-price products, than using products referencing British, Dutch or German power prices. Given this, it may be more relevant to think of market participants hedging NO2 price risk using products referenced against price in other zones than vice versa.

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12 See, for example, the organisations listed as participating in transmission rights auctions on the JAO website <https://www.jao.eu/>.
The absence of exchange-traded NO2 hedging products doesn’t completely preclude the possibility of market participants with foreign price exposures seeking to construct hedges using, for example, a combination of Nordic system price contracts and transmission rights for one of the interconnectors. Indeed, at least one generator with exposure to the Dutch power price expressed an interest in this possibility as part of the study conducted in 2012. However, a transmission right linked to the NO2 price then becomes less relevant in supporting the resultant proxy hedge, albeit not useless, since it fails to cover any difference between the NO2 and system price.

Overall however, we suspect that market participants with NO2-price risk exposure are likely to be the most obvious beneficiaries of enhanced hedging opportunities, given that they currently have no exchange-traded product through which to hedge NO2 price risk.

4.4.3 The types of hedging products used by different market participants

Different types of market participants are looking to hedge price risk over different durations and with different profiles. As such, hedging products designed to fulfil the needs of one participant may fail to address the needs of others. In considering whether transmission rights are likely to be helpful therefore, it is important to consider the extent to which the product’s characteristics address the specific needs of a particular set of market participants. In this section, we note some general differences in the hedging needs of different groups of market participants. While these observations are generalisations, and need not hold true in all cases, they are nevertheless useful in considering how specific transmission rights might be used to address different actor’s fundamental hedging needs.

Probably the most important driver of a market participants’ hedging needs is their fundamental role as a generator, supplier or consumer of power.

Suppliers’ risk power price exposure generally arises from entering into supply contracts with fixed, or partly fixed, prices. The supplier is therefore exposed to power price risk due to the need to purchase power to meet these supply obligations. Power price volatility is relatively large in comparison to the margin charged on the supply contract. A pure supplier will generally, therefore, seek to secure this margin by buying power sufficient to cover its supply obligations under any agreement shortly after the supply agreement is entered into. It may practice a so-called back-to-back hedging strategy, in which fixed-price supply commitments are fully or close-to-fully hedged as soon as they are made and any changes in expected volumes are quickly reflected in the volume of power hedged. Arranging back-to-back hedges means than suppliers need to have access to products that allow them to match the shape of the consumers consumption profile. Typically suppliers will be looking to use products with a granularity of not less than a month so that they can account for monthly changes in demand.

Where there are significant changes in market shares between suppliers, or rapid changes in the volumes of contracts with fixed prices, liquid hedging instruments are especially important to hedgers pursuing a back-to-back hedging strategy. Regular auctioning may therefore be essential to meet suppliers’ desire to create offsetting hedges quickly.

In contrast to suppliers, many generators and some consumers are typically willing to hedge over relatively long timeframes, extending over several years. Most transmission rights, in contrast, are issued for periods of a year or less, making them potentially less useful as a means to hedge a large and enduring power market position. Again, this is not to say that such rights will never be used by such market participants, but rather that their use might be confined to making marginal adjustments in these participants’ near-term hedging positions rather than meeting their longer-term hedging objectives.
5 THE SUFFICIENCY OF CURRENT HEDGING OPPORTUNITIES

The European legal framework, and specifically Article 30 of the Guideline on Forward Capacity Allocation, ties decisions on the issuance on transmission rights to the sufficiency of hedging opportunities in the concerned zones. In this chapter we briefly summarise some of the information relevant to a consideration of the sufficiency of hedging opportunities in the relevant zones. Section 5.1 summarises some of the key insights from the analysis of the NordREG Metrics, which are intended to enable a systematic assessment of the Nordic forward market across the Nordic regulators. Full details of these metrics are included in Appendix 1 alongside discussion of the equivalent values for the relevant non-Nordic bidding zones where data is available. Section 5.2 summarises insights gained from interviews with market participants, covering views both on the sufficiency of current hedging opportunities and the usefulness of transmission rights.

5.1 Evidence from the NordREG Metrics

It is important to note that the NordREG metrics do not establish a clear test for the determination of the sufficiency of hedging opportunities. They also only cover hedging conducted using exchange-traded products and so fail to include a variety of other hedging opportunities, such as the use of over-the-counter trading, hedging service providers and power purchase agreements. This issue is covered in detail in a report conducted on behalf of the Swedish, Danish and Norwegian National Regulatory Authorities. The report suggests that the vast majority of market participants make use of at least some form of bilateral hedging, which would not be covered by the NordREG metrics.

What the metrics can help to reveal are trend changes related to the exchange-based hedging products.

One notable trend is the recent decline in open interest in Nordic system price contracts, as shown in Figure 1 below.

*Figure 1: Open interest (TWh), Nordic system price contracts*

Open interest refers to the total size of open positions with a clearing house at a given point in time. When a market participant wishes to hedge a physical exposure to the power price using financial derivatives, they will create an open position for the relevant contract and keep this position until

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delivery. When a speculator trades such contracts, he or she will typically open a position by buying or selling the relevant contract and then close this position at a later point by making an offsetting trade. For example, they will try to buy the contract when priced low and then sell it at a higher price. As such, information on the size, distribution and dynamics of open interest can be used to infer the volume of physical exposures that are being hedged and the composition of products used to construct these hedges.

For individual contracts, there will typically be a steady increase in open interest from the beginning of the trading period until the last trading day before delivery. This occurs as hedges are built up over time. Just ahead of delivery there is a sudden drop in open interest caused by cascading, the process by which open positions in a specific contract are transformed into open positions in shorter contracts covering the same delivery period. For example, open positions in a yearly contract are transformed into open positions in four quarterly contracts. The resulting drop in open interest in the yearly contract is therefore perfectly offset by the increase in open interest for quarterly contracts. This results in the zig-zagging of total open interest for contracts for specific durations in Figure 1 above.

Figure 1 shows that the bulk of open interest in Nordic system price contracts is established in yearly contracts. It also shows that total open interest was stable from around 2013 to 2018, but there is a notable decline from the start of 2019. This decline suggests that the volume of exposures being hedged may have fallen.

In contrast, open interest in EPAD contracts has experienced a slight increase (see Figure 2) and there is a notable uptick in open interest in the NO1 EPAD recently (see Figure 3), albeit from relatively low absolute levels.

**Figure 2: Open interest (TWh), EPADs, all bidding zones**

Data source: Nasdaq
The growth in open interest in NO1 EPADs, which suggests that larger exposures are being hedged using these contracts, seems to begin around mid-2018. More recent growth in the use of NO1 EPADs, and of EPADs more generally, may reflect higher perceptions of area price risk in 2020, when the Nordic system experienced atypically large price dispersion among bidding zones. This reflected a combination of record-high water reserves in Norway and limited transmission capacity between Norway and Sweden due to transmission outages.

The other point worth noting from the metrics is the extremely high historic correlation between NO2 prices and those in NO1 and NO5. Over the last five years, monthly average prices between these zones have effectively been perfectly correlated. Monthly averages of the spread between the area price and the system price, which is the reference of the EPAD product, are also high at 0.85 (NO2 and NO1 spreads) and 0.96 (NO2 and NO5 spreads). This high historic correlation implies that NO1 EPADs may have been an effective substitute for an NO2 EPAD. However, it is worth underlining that this analysis is exclusively backwards-looking and the presence of greater interconnection into NO2 is likely to weaken this correlation in the future.

5.2 Evidence from stakeholder interviews

THEMA recently interviewed a variety of Nordic market participants on the sufficiency of hedging opportunities in the Nordic markets on behalf of the Danish, Swedish and Norwegian energy regulatory authorities. In parallel with these interviews, we interviewed several actors representing market participants in the Norwegian, German, British and Dutch markets to solicit their opinions about the potential impact of transmission rights on the NordLink, NorNed and North Sea Link cables. We conducted six interviews with participants outside the Nordics as part of this work. These included interviews with the branch organisations for electricity utilities in Germany and the Netherlands, the European Federation of Energy Traders and several energy trading companies active in the use of transmission rights. In this section, we summarise the key insights from these interviews.

As part of the work for the Danish, Swedish and Norwegian energy regulatory authorities, market participants with exposure in one or more of these markets were invited to answer an online questionnaire on hedging opportunities and the sufficiency of current hedging arrangements in the Nordics. In total, 59 market participants responded to the online questionnaire, of which 15 were Norwegian stakeholders. Following the survey, a representative subset of the survey respondents was invited to a more in-depth interview in which options on how to improve hedging opportunities in the Nordics were discussed. The interviews with the Norwegian actors also covered the
stakeholders’ opinions on the issuance of transmission rights across the three interconnectors. A total of 10 Norwegian stakeholders were interviewed, including one stakeholder that did not answer the online survey.

The survey participants were asked two questions on the sufficiency of hedging opportunities in the Nordics: one covering their own hedging activities and one on the general sufficiency of available hedging arrangements. Figure 1 summarises the stakeholders’ responses to these questions. More than half of the questionnaire respondents believed that there were insufficient opportunities to hedge power price risk in the Nordics. Looking only at Norwegian respondents, a similar share thought they had insufficient opportunities to hedge their power price risk exposure.

Figure 4: Survey respondents’ views on the sufficiency of current hedging opportunities in the Nordics

This belief that there are insufficient hedging opportunities does not appear to be restricted to a subset of Nordic bidding zones, nor are there obvious differences of opinion among different stakeholder types. It is possible to characterise the sorts of organisations that were likely to consider hedging opportunities to be sufficient. These include (i) large generator or trader organisations with trading desks and relatively sophisticated hedging operations, (ii) large consumers that have found success using PPAs, and (iii) retailers that are happy with the hedging solutions provided by brokers or hedging service providers.

The vast majority of those Norwegian stakeholders that stated that there were insufficient opportunities to hedge power price risk cited a lack of liquidity and depth in the EPAD market as the most serious problems. NO2 and NO5 notably do not have an exchange-listed EPAD, but OTC options are available. Many different factors were noted as potentially contributing to the lack of liquidity. EPAD liquidity was thought to be undermined, in particular, by the small number of actors present in each zone as well as – in some zones – the asymmetry of generation and consumption volumes and the presence of market power. It was observed that the EPAD market is almost exclusively used by market participants with physical exposure to the underlying area price since financial speculators are unwilling to trade in such illiquid products. Consequently, in zones with asymmetric generation and consumption, one side of the market is always lacking potential counterparties.

The stakeholders also raised a wide variety of possible options that might be considered to improve hedging opportunities. These options are discussed in more detail in the other report.

Regarding the responses of market participants on the issuing of transmission rights, those actors outside the Nordics were all of the opinion that transmission rights should be issued. Norwegian actors were more cautious and, while not universally opposed, were either concerned about the
potential implications for liquidity in Nordic hedging markets or failed to see any direct benefit or relevance to them.

The liquidity impacts of issuing auction rights are discussed in more detail in section 7.4. Advocates of the use of transmission rights noted that the issuing of such rights would support the liquidity of related products at both ends of the cable. This is consistent with the idea that transmission rights will predominantly be acquired by trading companies since these companies are likely to make additional trades to offset their exposure to the cable price spread. In this scenario, one would imagine that the trading company might trade in Nordic system price futures as part of a trading strategy involving the purchase of transmission rights on the cables, thereby supporting the liquidity of Nordic hedging products.

Large Norwegian utilities, while sometimes acknowledging the argument above, would also highlight a potential risk to Nordic liquidity stemming from the substitution of Nordic hedging products with non-Nordic alternatives – the bridge to liquidity argument discussed in section 4.3. For these actors, any (further) decline in the liquidity of Nordic products was seen as a redline with further consideration needed as to the risks posed to liquidity in the Nordic market.

We discussed this concern with many of the non-Nordic actors. They did not consider that there would be any significant negative effect on liquidity, although the reasoning offered differed. One respondent noted that local hedging would always be preferable due to the avoidance of basis risk, although it should be noted that area price hedging in NO2 may be a challenge. Another noted (correctly) that some Norwegian actors already use foreign power futures as hedging instruments. As a result, they argued, any additional impact on Nordic liquidity was likely to be muted. A Norwegian actor noted that the size of the bridge-to-liquidity effect might well depend on how far ahead of delivery transmission rights were issued. Specifically, transmission rights for more distant delivery periods (beyond Y+1) would make hedging in foreign markets more viable. However, if transmission rights were only issued for the relatively near term, they were unlikely to play any significant role in hedging. Based on our discussions with trading companies, it does appear to be true that they are most interested in relatively near-term products.

We also discussed how the absence or illiquidity of NO2-referenced products would affect trading companies' interest in transmission rights referenced against the NO2 price. The presence of liquid hedging markets at either end of the transmission right was deemed to be preferable, but not essential. This suggests that trading companies would participate in any resultant auctions, but that the price paid for the rights might be adversely affected by the difficulty trading NO2 price risk. Although NO2 price exposure could theoretically be traded over-the-counter, one trader noted that over-the-counter trades in illiquid zones generally implied trading with incumbent local utilities at punitive rates. One trading company suggested that the issuing of auction rights ought ideally to be looked at in conjunction with efforts to establish an exchange-traded NO2 EPAD contract, given the complementary nature of these products. It was also noted that, although a lack of liquidity in NO2 products might detract from the value to traders of transmission rights, these rights could be especially valuable if the trading desk had a view on the NO2 price that it wished to trade. In this case, the transmission rights would be one of only a few ways to implement a trading strategy.

It should be noted that smaller market participants with fundamental power price exposures, as well as Nordic market participants with exposures outside NO2, generally showed no interest in using transmission rights on the cables. Those outside NO2 considered these rights to be irrelevant to their needs since they would not reflect the area price to which they were exposed. Smaller players generally objected to the increased complication of potential hedging products and did not have the administrative capacity to conduct complicated hedging strategies involving transmission rights.

Given the disinterest of smaller players, one might conclude that they are unlikely to benefit from the issuance of transmission rights. However, it is worth noting that a trading services provider suggested that, to the extent that transmission rights allowed it to manage power price risks at a lower cost, for example through the use of a bridge to liquidity, this cost reduction could be shared with its customers through lower cost hedging services.
Options to improve hedging opportunities in the Nordics

Issuing transmission rights on the external borders of the Nordic system is just one of many options that have been suggested to improve hedging opportunities in the Nordics. In this box, we provide a brief overview of some of these options.

Bidding zone redesign

This option involves restructuring bidding zones so that they are made larger and more balanced. Larger bidding zones would tend to increase the number of actors that are interested in trading each zone’s financial products, while more balanced bidding zones would help to avoid a situation in which one side of the market cannot find a counterparty. A softer option would be to include these objectives in the long-term framework for defining bidding zones in the hope of encouraging gradual changes to bidding zone definitions over time.

Creating regional EPADs

Regional EPADs could be created by pooling one or more EPADs into larger, regional EPAD-like products referenced against new regional reference prices. This would pool the liquidity of each included EPAD, but leave the liquidity of system price contracts untouched. The choice of how to pool EPADs would presumably be made to reflect the expected future price correlation between the underlying bidding zones. There is a trade-off here, similar to that for the Nordic system price, in which products for larger areas give rise to potentially greater liquidity at the costs of weaker correlation with market actors’ underlying price exposure.

Changing the definition of the system price

Changes could be made to the system price to try and improve the reference price’s correlation with actors’ underlying price exposure. One option, related to the idea of regional EPADs above, would be to split the Nordic system price into a series of regional reference prices that more closely resemble the price exposure of different regions in the Nordic system. Doing so would, however, split liquidity in Nordic system price contracts. Another option would be to keep a system-wide price but to change its definition. For example, the price could become a volume-weighted average of area prices. This would increase the correlation between the system price and high-volume bidding zones, but potentially worsen the correlation with other areas.

Enhanced market making

A market maker is obligated to post bids and offers for a product, thereby ensuring the presence of a counterparty and a price. The obligations typically specify a minimum volume that must be made available and a maximum bid-ask spread. Market makers are generally compensated for taking on these obligations in the form of lower trading fees or direct payments. However, in some cases, the obligation is imposed by regulation and uncompensated.

This option would entail enhancing the market making arrangements currently in place, either by enhancing the conditions imposed on market makers or increasing the number of market makers. In either event, market makers as a group would face greater costs associated with these enhanced commitments and would likely demand compensation to undertake them voluntarily.

Broader market participation

Market stakeholders sometimes point to a lack of participation by small or demand-side players as a cause of low liquidity. Expanding market participation is therefore offered as a potential remedy. Suggestions include altering exchange membership requirements, changing credit and collateral requirements and reducing minimum contract sizes. Other interventions suggested by

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market participants to attract specific types of user include changes to the product offering, such as the use of contracts with physical delivery, and the listing of longer-dated monthly contracts.

**Forcing (large) vertically integrated companies to trade**

Vertically integrated companies, for example with generation and supply businesses, can hedge internally between these business units. In some jurisdictions with large vertically integrated generation and retail businesses, regulators have effectively required these companies to conduct at least some of their hedging activity via the exchange. For example, the generation and retail business units may be required to operate distinct trading desks and, if necessary, trade with one another via the exchange. This supports both greater price transparency and adds liquidity to the market.

**Implementing auctions**

Adding auctions can help to create a focal point for trading activity that is absent in a continuous market, enhancing liquidity at the focal point. Auctions can also help to lower the costs of participation, especially for smaller players that do not wish to dedicate the resource to monitoring the market over an extended period, potentially encouraging greater participation.

**TSO supply obligations**

The compulsory sale of transmission rights by TSOs, as implemented in Continental Europe, is effectively a supply obligation placed on TSOs to support the availability of cross-border hedging opportunities (see the next chapter for a description of the use of transmission rights for hedging). This report focuses on the issuance of such rights for interconnectors on the borders of the Nordic system. However, similar obligations could be implemented within the Nordic market, between Nordic bidding zones. Alternatively, the nature of the supply obligation placed on TSOs within the Nordics could be adapted to use existing products, such as EPADs.

It is worth noting that an obligation to supply transmission rights could be converted into a near-equivalent obligation to supply EPAD Combos – both transmission rights and EPAD Combos pay the price spread between two bidding zones. Such Combos can also be split and sold on as normal EPADs. As such, it may be possible to implement TSO supply obligations similar to those found in Continental Europe within the Nordic system without adding to or changing the existing set of products used for hedging.
6 ALTERNATIVE CROSS-ZONAL HEDGING PRODUCTS

Transmission rights can come in a variety of different forms and these differences affect both the extent to which transmission rights help meet market participants' hedging needs and their likely impacts on the wider market. In this section, we consider some alternative potential product designs and discuss some of the implications of these design choices.

6.1 Alternative transmission right designs

There are four primary properties of a right that we consider:

▪ Whether it is physical or financial
▪ Whether it is an obligation or an option
▪ The price spread to which the right is referenced, and
▪ The ‘firmness’ of the capacity provided by the right.

6.1.1 Physical vs financial rights

Traditionally, transmission rights were ‘physical’, meaning that the right allowed the holder to nominate flows on the associated transmission capacity. These rights also allowed their holders to move power owned physically in one zone to another zone. The nominated flows would then feed into the market clearing solution.

The use of physical rights fell out of favour because the nomination of these rights frequently resulted in the inefficient use of transmission capacity, as market participants failed to correctly anticipate the price spread across the relevant zones. This resulted in the implementation of Use It or Sell It (UIOSI) conditions on these rights, which effectively meant that if the holder of the right failed to nominate a specific flow, the capacity would be sold into the day-ahead clearing process and the right’s owner would be paid the resulting spread. As a general rule, the most profitable thing for Physical Transmission Right (PTR) holders to do was to simply not nominate the capacity. Nomination simply risked mis-forecasting the price spread. Instead, it was better to simply take the price spread resulting from the exercise of the UIOSI condition.

For Financial Transmission Rights (FTRs), the right’s holder is entitled to the price spread across the border in the day-ahead market. This is equivalent to having a PTR and then always making use of a UIOSI condition. In this case, there is no possibility of the right holder affecting the physical market. As the name suggests, the product is purely financial.

PTR products in Europe have been replaced by FTRs on many borders as a means to help ensure the efficient use of transmission capacity. FTRs ensure than transmission decisions are fully determined by the market coupling solution and that available transmission capacity is used to flow power from low- to high-price areas.

Some actors have noted that PTRs may be useful as a means to sell energy services, such as balancing reserves, across borders. While some form of ability to reserve transmission capacity would be necessary for private actors to sell such services across borders, it’s not clear that traditional PTRs, which allowed the nomination of flows, would themselves be sufficient for this task. In addition, the European target model envisages the cross border exchange of such services will be arranged between TSOs directly, rather than via TSOs contracting with providers in other TSOs’ control areas. In the discussion that follows therefore, we primarily consider FTRs and the use of transmission capacity as a means of exchanging energy between connecting market, rather than possible alternative uses of transmission capacity.

6.1.2 Obligations vs options

An individual transmission right product will cover a specific direction of flows on the border. For example, there will be one product that covers flows from market A to market B and a separate product covering flows in the opposite direction.
A Financial Transmission Right obligation will pay out the spread that would be earned from flowing power in the specified direction, regardless of whether the price spread is positive or negative. So, an FTR obligation on flows from market A to market B will pay $P_B - P_A$, since we notionally assume that revenues are earned by selling power in market B and that power is bought in market A. If the price in market A is lower than in market B, this arbitrage is profitable and the holder of the FTR obligation gets paid. However, if the price in market A is higher than in market B, the holder makes a loss and is liable to pay.

An FTR option operates in effectively the same way except that the right’s holder is not responsible for paying anything when flows in the specified direction would result in a loss to them. As such, unlike an obligation, an option cannot result in the holder of the right being liable to pay. This means that, whereas the value of an FTR obligation may be negative, i.e. the obligation may have a negative price, an option must always have a non-negative price.

### 6.1.3 The reference price

Financial transmission rights have historically been referenced against the day-ahead price spread between the two connected bidding zones. It is therefore natural to think of transmission rights on the NordLink, NorNed and North Sea Link cables being referenced against the spread between the NO2 area price and the price in the adjoining bidding zone. However, given the absence of exchange-traded NO2 hedging products, the importance of the Nordic system price in the structure of existing Nordic hedging products and the historically high correlation between NO2 and system prices, we also consider the implications of products referenced against the spread between the Nordic system price and the non-Nordic bidding zone price.

### 6.1.4 Firmness

Firmness refers to the issue of whether the volumes defined in the contract are fixed in the contract or tied to the actual market flows in the day-ahead market. If the capacity is firm, i.e. fixed, the TSO is obliged to pay the price difference between the two bidding zones multiplied by a predefined contracted volume even if actual power flows on the cable are lower than this. If the capacity is not firm, the TSO will pay an amount equal to the congestion rent earned from the market flows in the day-ahead market.

Critically, firm products imply that a TSO will make pay-outs for transmission rights even when an outage prevents the TSO from earning congestion incomes. Conversely, non-firm products leave the right holder exposed to the operational risk of the transmission asset.

In general, FTRs are firm subject to caps on the total payments that TSOs are required to make in the event that transmission capacity is constrained. Article 54 of the Guideline on Forward Capacity Allocation States that:

> “The cap shall not be lower than the total amount of congestion income collected by the concerned TSOs on the bidding zone border in the relevant calendar year. In case of Direct Current interconnectors, TSOs may propose a cap not lower than the total congestion income collected by the concerned TSOs on the bidding zone border in the relevant calendar month.”

### 6.2 The implications of product design on hedging

In this section we consider how these properties will influence the transmission right’s ability to help meet the needs of hedgers.

In section 4.1, we distinguished between two different types of hedging. Specifically, we noted that transmission rights could conceivably be used to hedge:

1. A direct exposure to the price spread across the relevant cable, or
2. An exposure to prices in one market using hedging products referenced against prices in the other market.
What is important to note here is that in both of these scenarios, the party wishing to hedge is exposed to the price spread between the two interconnected zones and wishes to hedge this spread.

As an example of the first case, consider a generator in the domestic market who sells power to a consumer or supplier in the foreign market at a fixed price. The generator receives the contract price, \( P_C \), in the foreign market. The power is physically fed into the domestic grid at a price \( P_D \). The generator will then have to buy power at \( P_F \) in the foreign market to deliver to the customer there. The payoff for the generator is then equal to \( P_C + P_D - P_F \) or \( P_C + (P_D - P_F) \). The price differential between the markets \( (P_D - P_F) \) is an uncertain exposure that the generator wishes to hedge.

As an example of the second case, imagine that the domestic generator wishes to hedge its future revenues using a future referenced against prices in the foreign bidding zone. This time let us say that it sells the power using a futures contract for price, \( P_C \). It will then have revenues of \( P_D + (P_C - P_F) \), where \( P_D \) reflects its revenues from domestic sales and \( P_C - P_F \) represents the exposure to the foreign price that it has gained by selling a futures contract in the foreign zone. A cursory examination of the formulas will show that this case is exactly equivalent to the first. It doesn’t make a difference whether our generator sells power physically to a consumer in the foreign market or sells power power via a futures contract in the foreign market. Ultimately, this results in the generator being exposed to the difference between the foreign and the domestic price.

In both these cases, a transmission right obligation provides the relevant offsetting exposure. In the example above, in which we are selling power from the domestic zone to the foreign zone, the generator gains an exposure to the spread \( (P_D - P_F) \). By purchasing an obligation to flow power from the domestic to the foreign zone, the generator receives a payment of \( P_F - P_D \), exactly offsetting this exposure.

One important point to stress here is that the value of such an obligation might be negative and so a process for allocating such obligations would have to be able to deal with the possibility that winning bidders might be paid take such obligations.\(^{14}\) To see this, imagine that prices in the foreign zone are typically lower. In this case, an FTR obligation to flow power to this lower-price zone implies that the right’s holder is liable to make a series of payments over the delivery period.

Also note that, while it might seem strange to imagine a generator selling power into a lower price market, this situation is more plausible when we consider the use of transmission rights as a bridge to liquidity.

Imagine, for example, that a consumer in NO2 wishes to hedge NO2 price exposures. It might seek to do this using comparatively low-cost German hedging products, by buying power forward in the German market using a German futures contract. This results in a residual exposure to the price spread between the NO2 and German power prices which could be offset by an obligation to flow power from Germany to NO2.

If we assume that the German power price is, on average, greater than that in NO2, this again implies that the consumer will wish to buy a negatively priced transmission right obligation as part of its hedging strategy. As the purchase of the German future doesn’t oblige the consumer to pay the full cost of the power up front, but rather to post collateral covering future changes in the price, the consumer needn’t be overly concerned by the average difference in the level of NO2 and German prices.

So far, we have only considered the use of obligations. Options will result in identical outcomes where the price spread between the zones implies a payment to the transmission right holder. However, options imply zero payment otherwise. This can be useful where the hedging party only wishes to hedge downside risk but, as we discuss below, may frustrate the use of transmission rights as a bridge to liquidity.

\(^{14}\) In practice, we might imagine a system of deferred settlement being used to help limit issues of counterparty risk. This would allow the obligation to have its intended hedging properties but prevent significant cashflows immediately after the auction then having to be reversed throughout the delivery period.
Let us imagine again the case of the domestic generator selling power in the foreign zone. The generator buys an option on transmission capacity from the domestic to the foreign zone. Such an option will pay $P_F - P_D$ where $P_F - P_D > 0$ and will otherwise pay nothing (see Figure 5 below). The total revenues to the generator are now, $P_C + (P_D - P_F) + (P_F - P_D)$ where $P_F - P_D > 0$. After cancelling, this is $P_C$ where $P_F - P_D > 0$. In other words, if the price spread between the zones is such that prices in the foreign zone exceed those domestically (the right-hand side of Figure 5), the option will offset the generator’s losses due to the adverse price spread. This establishes a minimum revenue for the generator of $P_C$ where $P_F - P_D > 0$. In other words, if the price spread is such that domestic prices exceed foreign prices (i.e. $P_F - P_D < 0$), the option is not exercised and has a value of 0. This implies that the generator’s revenues are $P_C + (P_D - P_F)$. This is the same as they would have been without using the option. Put simply, in this case, the generator gets to keep the upside.

**Figure 5: Example of the use of transmission right options**

A potential problem arises however when we want to use our transmission rights options as a bridge to liquidity. At the heart of this problem is that we may wish to buy power in a relatively high-price market or sell power in a relatively low-price market not because absolute energy prices are more attractive there, but because hedging opportunities are better.

Consider again the case of the consumer in NO2 trying to hedge exposure in, we assume here, a relatively high-priced German market. This is achieved by buying a German futures contract. As before, this leaves the consumer exposed to the price spread between the markets. Previously, we assumed that the consumer covered this exposure by buying a negatively-priced FTR obligation to flow power from Germany to NO2. Now imagine that only options are available on the relevant border and that the consumer now purchases the corresponding option. As an option, the contract only has an effect when NO2 prices are greater than German prices. If we assume that this is rarely the case, and there is a strong underlying price wedge between the two markets, the option will rarely if ever have any effect (we will be on the far left of Figure 5). What this means in practice is that the option will not support bridge-to-liquidity hedging because actors cannot effectively hedge the price spread between the associated markets.

The consumer could, in this case, gain the relevant exposure by selling an FTR option in the opposite direction. However, to our knowledge, market participants cannot originate their own FTR option contracts.

In summary therefore, FTR obligations more naturally fulfil the needs of hedgers wishing to use these rights as a bridge to liquidity. However, obligations can have negative prices, potentially implying that auction participants are paid at auction by the relevant TSO.

The choice of the reference price depends ultimately on the fundamental exposure of the party seeking to hedge. Market participants in NO2, for example, will clearly benefit from products that reference their area price. Hedgers with exposures elsewhere in the Nordics would likely prefer products referenced to the system price, as they will be more easily able to manage exposures.
relative to the Nordic system price than relative to the NO2 price. Similarly, to the extent that hedgers in non-Nordic zones wish to use the cables to hedge using Nordic products, this will be made far easier by transmission rights referenced to the Nordic system price.

Regarding firmness, hedgers will generally prefer contracts that are as firm as possible, since they will not wish to take on exposure to the operational risks of the transmission assets. Any limitations to the firmness of the product will be reflected in the willingness to pay for the products and should therefore be reflected in price of these products at auction.

6.3 The implications of product design on trading

It is important to realise that transmission rights will often not be acquired directly by market participants wishing to hedge. Rather, they will be acquired by traders looking to profit directly from trading. To give a somewhat stylised example, imagine that a trader has the option of participating in an auction for FTR obligations, which will result in a specific exposure to the price spread between two bidding zones. The trader is also active in the futures markets for both zones and so can take positions in these futures markets that provide an offsetting exposure. Given this setup, the trader could, for example, buy an FTR obligation and then trade futures contracts such that it was left with no residual price exposure to either bidding zone. If the price of the FTR obligation is low enough, this set of trades can leave the trader with a profit. The trader will therefore bid into the FTR auction at prices at which it thinks it can turn a profit. In effect, the trader is acting to arbitrage a variety of risk management products. This activity not only helps to ensure that pricing is consistent across these interrelated products but can also provide liquidity to the products that are traded.

What implications does product design have for trading activity like that described above?

Traders generally prefer financial contracts, as they do not intend to make use of the nomination capability of physical rights and the weaker the link to physical capacity, the easier it is to make the case for firmness. However, if a physical contract enabled financial settlements and did not imply any additional administrative burden or weaker conditions in relation to firmness, traders would presumably be indifferent between the two.

Firmness is important to ensure that the product is attractive to pure traders. Again, trading desks do not want to take on exposure to the operational risk of the physical infrastructure, which are more difficult for them to manage. Ideally, they want contracts that are fully firm, as this allows exposures to be more perfectly matched with those provided by other financial derivatives like futures.

When it comes to the preferred reference price, a product that is referenced against the Nordic system price results in exposures that are far easier to manage through the use of relatively liquid Nordic system price contracts. In general, this will make participating in auctions for the transmission right product more attractive and the rights issued more valuable. However, it should be noted that if a trading company has a view on the NO2 price, the absence of other NO2-referenced products would make trading transmission rights the only way to take a position on the area price and therefore potentially valuable for that reason.

<table>
<thead>
<tr>
<th>Implications of the NSL price-coupling solution</th>
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<tbody>
<tr>
<td>Due to the United Kingdom’s exit from the European Union, power price coupling arrangements between the Norwegian and British markets will be revised. Under the system currently being proposed, a separate day ahead auction will be held for the British and NO2 bidding zones shortly ahead of the European Single Day-Ahead Coupling auction. This process will result in two distinct day-ahead prices for NO2, one from each auction. Transmission rights on NSL that referenced relative to the NO2 price will presumably need to specify which of these two prices will be used in calculating the price spread. We briefly consider the implications of the choice here.</td>
</tr>
<tr>
<td>For market participants seeking to hedge a physical exposure in NO2, the choice is unlikely to be a significant issue since these participants are expected to be able to participate in either</td>
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auction. They can therefore choose to trade in the auction referenced by the transmission right and thereby avoid basis risk, i.e. the risk of a mismatch between the price to which they are exposed and the price against which they are hedged.

Traders are unlikely to have this flexibility. Instead, they will be looking to implement trading strategies by combining positions across multiple products. They will wish to avoid a situation in which financial products use inconsistent reference prices, as this will prevent them from combining these products without also taking on basis risk, i.e. exposure to a mismatch in the different NO2 day-ahead prices. There are currently no exchange-traded products referenced against the NO2 price. However, over-the-counter EPADs are occasionally used. To the extent that traders wish to use these or other NO2 products in conjunction with transmission rights, the different products should be consistently referenced. If this is not the case, it may adversely affect the value of transmission rights to traders, consistent with their increased exposure to a mismatch between the different NO2 day-ahead prices.

Regarding the distinction between options and obligations, we did not discuss this with the trading firms as part of the interviews we conducted. Part of the rationale behind the prevalent use of FTR options is that they avoid a situation in which the holders of transmission rights can become liable to make payments to the TSO. This means that the TSOs do not need to worry about counterparty risk and, by extension, that traders do not need to worry about posting or managing collateral, which could be a significant additional complication. It also means that secondary trading of rights is simplified as, again, the credit worthiness of the right holder is irrelevant. That said, many of the international energy companies that already trade in transmission rights would be more than capable of managing collateral requirements were these a part of the market design and, in theory at least, clearing services could be arranged to enable the secondary trading of transmission right obligations.

6.4 The implications of product design for TSOs

In general, TSOs are likely to prefer the use of financial transmission rights to physical transmission rights as this avoids any potentially complicating interaction with operational decisions. That said, TSOs are also generally advocates of limits to firmness. Such limits imply that operational risk for the cables is shared with the holders of transmission right such that TSOs, or their tariff payers, are less significantly affected by unexpected shortfalls in congestion incomes due to restricted cross-zonal flows.

It should be noted that this sharing of risk with transmission right holders is likely impose a cost on TSOs (or tariff payers) if, as one would expect, a lack of firmness results in rights achieving lower prices at auction. Put simply, bidders for transmission rights should expect to get these rights at a discount if they must share the operational risk with the TSO. Given that transmission right holders have limited options to manage this risk, they may well expect discounts that are a bad deal for the TSO, particularly if, as is generally the case, the TSO does not place a minimum or reserve price on the sale of transmission rights.

One interesting implication of the use of transmission right obligations, as opposed to options, is that obligations in opposite directions across the same border provide symmetric and opposing payment obligations much in the same way that a buyer and seller of a futures contract have offsetting positions. What this means is that obligations in one direction across a border can be netted against obligations in the opposite direction. In theory, any arbitrarily high capacity can therefore be sold in one direction across a border provided that an equally large capacity of obligation is also sold in the opposite direction. Indeed, since these are ultimately just financial derivatives for two sides of the same price spread, there does not need to even be any transmission capacity across the border and, in theory, the TSO could be removed entirely from the process. Such a system would rely on there being equal numbers of contracts sold in each direction, but this is not an insurmountable problem, as it just requires that the auction clear the sale of both products simultaneously. It also requires that there are participants willing to buy capacity in both directions. If the capacity is being used as a bridge to liquidity, then provided this ‘bridge’ is being used by market participants that are
net long and net short, there will be demand for capacity in both directions. However, even if there is some asymmetry in the size of physical hedgers, some of the mismatch could in theory be met by trading desks that take a position and manage the exposure in a different way. It might also be possible to establish and auction for obligations that allowed there to be a difference in demand in both directions up to the physical transmission capacity available between the zones with the TSO becoming the counterparty for this difference.

Despite these apparent advantages of obligations, and as noted above at the end of the previous section, the fact that obligation holders can become liable to make payments implies that TSOs will be exposed to counterparty risk and might well require the clearing of such contracts. This would potentially add significantly to the complication of administering the contracts for all parties.

With regard to the choice of the reference price, TSOs are likely to prefer a reference price that matches the structure of actual congestion incomes. For the cables under consideration, this will be the NO2 price. Were the TSO required to issue ‘transmission rights’ relative to the Nordic system price then it, or more accurately network tariff payers, would be exposed to the area price due to the mismatch between congestion incomes (earned relative to the NO2 price) and transmission right obligations (paid relative to the Nordic system price).
7 COSTS AND BENEFITS OF LONG-TERM TRANSMISSION RIGHTS

In this section, we set out the framework used for considering the costs, benefits and distributional impacts of issuing LTTRs on the NordLink, NorNed and North Sea Link and conduct some quantification on the potential size of these impacts.

7.1 Framework for considering impacts

Here we set out the theoretical framework we have used to consider the potential impacts of issuing LTTRs on interconnectors. This framework has been constructed by combining our own consideration of the issues, insights from the relevant literature and discussions with stakeholders. It is intended to be a comprehensive account of the various impacts that might theoretically result from the issuance of LTTRs. A consideration of the relevance and scale of these impacts for the NordLink, NorNed and North Sea Link cables is contained in sections 7.2–7.5.

7.1.1 Benefits

The issuance of LTTRs may result in three potential types of benefit, discussed further below. Issuing LTTRs may:

1. Improve the transparency of the market’s future power price expectations,
2. Reduce the economic costs associated with hedging power price risk, and
3. Reduce barriers to entry into markets in which power price risk management is important (such as electricity retail and generation).

Improved price transparency

As noted in section 2.2, transparent market expectations about future power prices support efficient decentralised decision-making. If the market’s expectations about future prices are clear and well-founded, the insight of the market can feed into a variety of economic decisions, such as the pricing of electricity-intensive goods or retirement decisions of generation capacity. The inclusion of the market’s insight on future price helps to ensure that these decisions are themselves well-founded and efficient. In contrast, a lack of transparency means that the information held by the market and expressed in the price is not effectively conveyed. The decisions that might have benefited from this information tend to be less efficient as a result.

LTTRs could potentially add to the transparency of market price expectations by providing publicly accessible pricing information on the LTTR product. Depending on the design of the product and the competitiveness of the auction, the LTTR price may be a good proxy for the expected price spread across the cable. In theory at least, this price may therefore contain useful information on the market’s expectations on future prices, which could be used more generally.

Reduced economic costs associated with hedging power price risk

Hedging activity itself involves some economic costs. Drawing from the academic literature on the costs of market making, we can distinguish between at least three types of costs faced by providers of financial hedging products: order processing costs, inventory holding costs and adverse selection costs. Order processing costs represent perhaps the most obvious costs associated with the trading of financial products and include things like, for example, the costs of exchange membership, labour costs and the costs of IT infrastructure and equipment. Inventory holding costs reflect the fact that, as financial products are traded around among participants, some participants may be asked to temporarily hold inventory positions that they don’t want. In this case, they may be over or underhedged for a time. This exposes them to risks they do not wish to hold and may also impose a capital cost if they have capital tied up in unwanted hedging products. Finally, adverse selection costs reflect the fact that information that is relevant to future prices may be held privately before being reflected in market prices. Traders in hedging products take the risk that they are trading with someone who has better information than them and that the trade is therefore not in their interests.
Bearing this risk imposes a real cost on them. Collectively these economic costs are reflected in the bid-ask spread quoted for financial products, as traders seek to be compensated for bearing these costs in their quoted bids and offers.

In theory, LTTRs may help to reduce these costs. We consider two possible mechanisms through which the economic costs of hedging may be reduced through the use of LTTRs.

First, and as described in section 4.3, LTTRs can act as bridge to liquidity, facilitating hedging using lower cost financial derivatives in connected markets. Here, the lower private costs of hedging using derivatives products with smaller bid-ask spreads may well reflect the lower economic costs involved in the use of these products. More liquid products may, for example, impose smaller inventory costs on traders. Enabling hedgers to use more liquid products will therefore tend to reduce the overall economic costs of hedging activity.

Second, LTTRs may actually help to improve liquidity and competitiveness in the markets for complementary products, thereby lowering the cost of hedging using these products. This may result from speculative activity, for example, where speculators seek to buy a transmission right but then to offset the resultant exposure by trading a portfolio of complementary products. By stimulating liquidity in complementary products, LTTRs may therefore help to reduce the economic costs of hedging using these products.

**Reduced barriers to entry**

In some markets, and as discussed in section 2.2, a business’ ability to effectively manage power price risk may be critical to its competitiveness and ultimate viability. Where power price hedging opportunities are limited or excessively costly, this can form a barrier to entry into the relevant market and thereby weaken competition and efficiency in that market.

For example, a lack of liquidity in hedging markets has been a significant source of concern for the British NRA, Ofgem, owing to concerns that this has created a barrier to entry into the retail and wholesale power markets.\(^{15}\)

To the extent that LTTRs help to reduce the costs of hedging and support the liquidity of complimentary hedging products, as discussed in the previous section, these effects may also have the additional benefit of reducing barriers to entry into markets where managing power price risk is important, thereby supporting competition in these markets.

Transmission rights may also support cross-border competition in the electricity retail sector directly, by enabling retailers with an established position in one bidding zone to sell generation or long-term purchases in their home bidding zone to customers in neighbouring zones.

**7.1.2 Costs and distributional impacts**

Three potential costs or distributional impacts are discussed in relation to the issuance of LTTRs. It is important to note that not all of these are socio-economic costs of the type that would be included in a formal cost-benefit analysis and we consider how these costs should be properly interpreted in more detail below. The three impacts considered here are:

1. Administrative costs – The implementation and operation of systems to issue and settle LTTRs has an administrative cost.

2. Firmness costs – Where the settlement of LTTRs is not strictly tied to the congestion income earned on the physical interconnectors, the issuing TSO may be obligated to make payments that are not offset by congestion income.

\(^{15}\) See [https://www.ofgem.gov.uk/electricity/wholesale-market/liquidity](https://www.ofgem.gov.uk/electricity/wholesale-market/liquidity)
3. Difference between LTTR revenues and payments – If there is a systematic difference between revenues earned from the issuance of LTTRs and payments under these contracts, this may have distributional impacts for market participants.

**Administrative costs**

The issuance of LTTRs implies the creation and operation of systems to both issue and settle the relevant contracts. These tasks imply economic costs in the form of labour costs and IT and infrastructure costs. As discussed, further in section 7.3, the nature of these costs is fairly clear owing to the existence of a single body responsible for these functions within the EU and an obligation to use this body under the European Guideline on Forward Capacity Allocation.

**Firmness costs**

Although the concept of transmission rights is obviously grounded in the idea of the right to use physical transmission infrastructure, most LTTRs in the current European power market are really financial derivatives, so-called Financial Transmission Rights (FTRs). Settlement of these rights is generally not tightly linked to the availability of physical assets or to the congestion incomes earned by the TSO. As a result, it is entirely possible that a TSO that issues FTRs across a bidding zone border will be liable to make payments under these contracts even in the event that network outages constrain cross-zonal capacity across the relevant border and therefore limit the congestion income earned by the TSO.\(^{16}\)

However, it is important to note that the total potential mismatch between a TSO’s LTTR liabilities and the congestion incomes earned on its physical assets should not be interpreted as a cost of issuing long-term transmission rights.

First, this impact is not a true socio-economic cost due to the fact that any financial cost imposed on the TSO or tariff payers is directly offset by a financial gain to transmission right holders. Second, and perhaps more importantly, the bulk of any implied cost to the TSO or tariff payers will be realised even in the absence of issuing transmission rights and is properly attributed to the unexpected shortfall in transmission capacity rather than the issuing of rights. To see this, let us consider the implication of an unexpected reduction in cross-zonal transmission capacity with and without the issuance of transmission rights.

If transmission rights are not issued, then the unexpected outage results in an unexpected reduction in congestion incomes.\(^{17}\) This is a genuine economic cost and is borne by tariff payers in the form of higher tariffs. If transmission rights are issued, this reduction in congestion incomes is unaffected and so this impact can be ignored. The TSO will now be obligated to make payments based on the cross-zonal price spread, as was the case when the cable was in operation, and will have received auction revenues that should reflect the value of such payments (something we return to in the next section). The only additional cost experienced by the TSO will reflect the fact that price spreads are potentially wider than anticipated as a result of the unanticipated outage. As such, the outage may lead to payments to the holders of transmission rights that are higher than those anticipated and, critically, higher than reflected in the TSOs auction revenues. Again, this is not a socio-economic cost, but a distributional transfer from the TSO (tariff payers) to transmission right holders reflecting the fact that the price spread was higher than expected. This transfer could also flow in the opposite direction, to the benefit of tariff payers, if price spreads were smaller than anticipated, for example because cable availability is greater than was anticipated at the time of auction.

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\(^{16}\) Article 59 of the harmonised allocation rules for LTTRs details the limits to TSOs’ liabilities to make payments in the event of restricted transmission capacity. See: https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/ANNEXES_HAR_DECISION/Annex%20I_171002.pdf

\(^{17}\) The total effect is complicated by the fact that an outage may affect congestion incomes on other borders but, for simplicity, let us restrict our consideration to the border on which the outage occurs.
Overall therefore, providing firm transmission rights does not add to economic costs. At most it adds to the fundamental transfer of price risk from TSOs (tariff payers) to transmission rights holders. With firm products, TSOs (tariff payers) will likely benefit from better than anticipated cable availability. The opposite will be true from worse than anticipated availability. In a well-functioning market, the implications of different firmness arrangements will be reflected in revenues received for the associated rights, with TSOs receiving greater revenues for rights that potentially imply larger pay-outs.

**Difference between LTTR revenues and payments**

The auctioning of LTTRs essentially involves selling ahead the future, uncertain stream of revenues earned by cross-zonal interconnectors. In a competitive market, the price of these rights, and hence the revenues earned for auctioning such rights, will reflect both:

- the market's expectations of the size of the future revenue stream, and
- a discount or mark-up on expected revenues that reflects the willingness of buyers to hold the risk associated with this uncertain revenue stream.

Some buyers may be willing to pay a premium for this risk if, for example, the rights help them to hedge their power price exposures at a lower total cost. This possibility is discussed in section 4.3. Others will only hold these uncertain cashflows at a discount – they are willing to speculate, but will only pay for the rights if they expect to make a return on average.

The demand curve for LTTRs may therefore be made up of bids from a variety of stakeholders. Each of these has potentially different expectations of the future level of the associated revenue stream and a different willingness to pay relative to these expectations.

Even if we assume that stakeholders’ expectations of the revenue stream are, on average, accurate, the fact that bidders' bids may be systematically above or below these expectations means that LTTR auction revenues may also be, in theory at least, systematically above or below the revenues paid out under the LTTR. The result will depend on the willingness of the price-setting bidder to pay a mark-up or discount relative to expectations, as well as the accuracy of these expectations.

If auction revenues tend to exceed pay-outs under LTTRs, this results in additional revenues for the TSO, which may be used to reduce network tariffs. However, if pay-outs under LTTRs tend to exceed auction revenues, this results in lower net revenues for the TSO, which may need to be compensated for by increased network tariffs.

Importantly, this effect is not, in itself, a socio-economic cost or benefit. It is purely a redistribution of funds among different market participants, namely network tariff payers and the buyers of LTTRs. The only way that this effect would result in a socio-economic loss is if this redistribution influenced investment decisions. For example, if Statnett failed to invest in a socio-economically beneficial interconnector because the financial returns to the cable were lower than the socio-economic benefits, this would represent an economic cost.

However, even if investment decisions are not affected by the direct financial returns to interconnectors, RME may still be concerned about the potential distributional impacts. If experience with existing JAO auctions is a guide, buyers of LTTRs on these cables are likely to be a set of relatively large and sophisticated power utilities, some local to the connected bidding zones and some involved in the trading of power market derivatives across Europe. In contrast, network tariff payers will reflect a broad spectrum of Norwegian network users. RME may be concerned about limiting any systematic flow of funds from tariff payers to the buyers of LTTRs and therefore wish to avoid a situation in which LTTR revenues are systematically lower than pay-outs.

### 7.2 Estimates of potential benefits

In this section we consider the likelihood scale of each of the impacts described above in the specific context of transmission rights issued on the NordLink, NorNed and North Sea Link interconnectors.
7.2.1 Improved price transparency

Of the bidding zones connected by the interconnectors under consideration, the British, Dutch and German power zones all have exchange-traded futures referenced against power prices in the respective zone. The prices of these products are publicly available and, as a result, it is doubtful that the introduction of transmission rights will make the market's expectations about price developments in these markets any more transparent.

The NO2 bidding zone is exceptional among the connected bidding zones in that there is currently no exchange-traded product referenced against the NO2 price and therefore no public price that reflects the market's expectations about future NO2 prices. Prices might be available through discussion with brokers, for example, but this is clearly a costly and less-transparent process for obtaining information on market expectations. It is therefore possible that transmission rights on these cables would make market expectations of NO2 prices more transparent.

Since transmission right prices, like EPAD prices, reflect expectations of the spread between two different power prices, participants would still need to combine information on the level of power prices in the other zone to infer an expected NO2 price.

Although the issuance of transmission rights on any single cable would contribute to the most significant single improvement in transparency, the issuance of rights on additional cables would likely still result in some marginal improvement to transparency. This reflects the fact, as discussed in section 7.1.2 above, that the auction price of the transmission right will reflect not only the expected price spread between markets, but also a potential mark-up or discount relative to this expected spread. The availability of prices for products on multiple cables will provide additional data that could be used to help isolate the market's price expectations from these mark-up and discount effects.

7.2.2 Reduced economic costs associated with hedging power price risk

As discussed in section 7.1.1 above, we identify two mechanisms through which transmission rights might reduce hedging costs. First, they can provide a 'bridge to liquidity' and enable market participants to substitute higher-cost hedging products with lower-cost products. Second, they can stimulate trading in complementary hedging products, for example as speculators close out a position gained via a transmission right. This can contribute to the liquidity of these other products, potentially reducing the costs of using them.

Whereas the first of these impacts reflects the use of transmission rights by fundamental hedgers, the second predominantly reflects the impact of speculative hedging activity.

Considering the second effect first, it is worth considering what complementary products speculators might use to close out a position gained via a transmission right on the relevant cables. As has been noted previously, there is no exchange traded NO2 EPAD. Traders will therefore naturally consider trading in Nordic system price contracts or, possibly, especially if they are local players, over-the-counter trading in NO2 EPADs. The marginal gains to liquidity in Nordic system price contracts are probably not very substantial in terms of the resultant improvement in the costs facing the users of system price contracts. However, improved liquidity in NO2 EPADs might have a significant impact on market participants' hedging opportunities and the costs of hedging NO2 area price risk.

In a best-case scenario, the presence of a transmission right linked to an NO2-price spread might actually help precipitate the conditions for the exchange trading of NO2 EPADs. To date, exchange-trading has been prevented by, among other things, an inability to find a willing market maker. Transmission rights could potentially stimulate additional interest in an NO2 EPAD product among the purchasers of transmission rights and provide useful information on the price of such an EPAD product. This could improve the liquidity of over-the-counter trade in NO2 EPADs, reduce the inventory costs associated with holding an NO2 EPAD position and reduce the likelihood of trading with a more informed counterparty (adverse selection cost). By providing an alternative mechanism to hedge NO2 price risk, the availability of transmission rights might also make it easier for market participants to act as a market maker for an NO2 EPAD.
Considering the first ‘bridge to liquidity’ effect, it is important to reiterate the point, discussed in detail in section 6.2, that the feasibility of bridge to liquidity hedging may depend on the nature of the transmission rights issued and the price dynamics between the various bidding zones. If transmission rights are issued as options, as is often the case elsewhere in Europe, and there is not a dominant price spread and flow on the cable, the value of transmission rights in supporting bridge to liquidity hedging may be minimal.

If we make the significant assumption that transmission design allows for bridge to liquidity hedging, then the size of the potential benefits depends on the size of the difference in hedging costs in different markets and the total volumes of hedging activity that can be moved to lower cost alternatives. The bigger the difference in hedging costs and the larger the volumes involved, the greater the economic gains that can be realised. Although the actual benefits involved are extremely uncertain, we can, at least, begin to get a sense of the scale of these potential benefits by examining these drivers.

The major contributors to differences in the costs of hedging using a locally-referenced product as opposed to via a bridge to liquidity are:

- differences in the bid-ask spreads for the relevant products, and
- any differences in exchange, trading or clearing costs.

Here we limit the quantitative analysis to a consideration of bid-ask spreads only. This is because:

- many exchange and clearing arrangements cover several markets, such that choosing to use a product referenced against a different bidding zone doesn’t necessarily imply adopting a whole different set of exchange and clearing costs, and
- many of these costs do not scale with trading volumes, such that the difference in costs across products is largely driven by assumptions on, for example, the scale of total volumes traded.

To compare the bid-ask costs associated with the use of different products, we look at information on average bid-ask spreads for yearly hedging products in each of the relevant markets. This data is taken from the ACER Market Monitoring Report 2019 and charted in Figure 1 below.

**Figure 6: Average bid-ask spreads of OTC yearly products - 2019-2021 delivery (EUR/MWh)**

[Graph showing average bid-ask spreads for different countries and years.]

**Source:** ICIS, via ACER Market Monitoring Report 2019

**Note:** Daily bid-ask spreads were averaged out throughout the period from 18 to 6 months before delivery start. For Great Britain, the half-yearly (winter and summer) products were used, and daily bid-ask spreads averaged out throughout the period from 12 to 6 months before the delivery start of each product.

Importantly, the Nordic data reflects hedging of the Nordic system price rather than the NO2 price. Hedging the NO2 price would require the use of an NO2 EPAD in addition to a Nordic system price contract and therefore add to the total costs of hedging.
We do not have data on the bid-ask spread of NO2 EPADs but can get an indication of their size by considering bid-ask spreads for the neighbouring NO1 EPAD, for which we have exchange data. Looking at NO1 EPAD contracts with 18 to 6 months to delivery, consistent with the ACER methodology above, suggests that the average bid-ask spread for these EPADs is around 0.64 EUR/MWh. We therefore assume that hedging using an NO2 EPAD implies bid-ask spread costs of 0.64 EUR/MWh. The actual spread may be even larger, due to the fact that the NO2 EPAD contract is not exchange-traded.

To estimate the potential reduction in hedging costs allowed for by the issuance of transmission rights, we consider the relative cost of two alternative hedges:

- a hedge constructed of Nordic hedging products, namely a system price contract, potentially combined with an NO2 EPAD, and
- a hedge constructed using a future contract for a connected bidding zone (Germany, Great Britain or the Netherlands) combined with a transmission right to the relevant bidding zone.

Here it is important to note two points. This first is that, in order for these two hedges to be equivalent, the transmission right would need to be transmission obligation from the foreign zone to NO2, as this will then pay-out the relevant spread in all circumstances, as discussed in section 6. The second is that acquiring a transmission right may also involve some transaction costs; however we effectively assume that these costs are equal to the administrative costs borne by the TSOs and discussed in section 7.3.1 below. It seems reasonable to assume that the economic costs borne by the buyers of transmission rights are negligible. In particular, as these rights are normally auctioned, there is no bid-ask spread paid by buyers and the costs of the auctioning platform are covered by the TSOs rather than by bidders. Given this setup, the benefits considered here can be meaningfully netted against the costs to TSOs discussed later.\(^{18}\)

Table 1 below shows how much lower bid-ask costs are if we choose to hedge the NO2 price using German, British and Dutch hedging products. It is based on the bid-ask spread data for 2019, 2020 and 2021 baseload contracts provided by ACER. The upper half of the table shows the cost difference assuming that the NO2 price risk is hedged using an NO2 EPAD and that bid-ask costs of 0.64 EUR/MWh are incurred as a result of using the EPAD. The lower half of the table assumes that we forgo using an EPAD and only hedge using a Nordic system price contract. This avoids the 0.64 EUR/MWh bid-ask cost incurred hedging the area-price risk, but leaves us exposed to any difference between the NO2 and system price. As a result, the Nordic hedging solution may actually be worse using this setup than the solution obtained using a transmission right.\(^{19}\) Positive numbers imply that using a product refenced against the foreign zone’s price is cheaper. Negative numbers imply that it is cheaper to hedge using Nordic products. In the latter case, it may be that market participants might wish to hedge exposures to a foreign power price using Nordic products. Thus, the top left cell tells us that the bid-ask costs of an NO2 price hedge consisting of a German baseload power future contract for delivery in 2019 and a transmission right were about 0.75 EUR/MWh lower than constructing effectively the same hedge using a Nordic system price contract and an NO2 EPAD.

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\(^{18}\) One may wonder why there is no cost attributed to LTTRs in this calculation despite the fact that the LTTRs will have a price. The reason is that this analysis focuses on the economic costs associated with different options, as opposed to their financial costs. In other words, we are looking at the options’ implications for the use of scarce resources. That is why we look at bid-ask spreads rather than the absolute price level of different instruments. The economic costs of LTTRs are almost exclusively borne by TSOs. As such, we effectively assume that LTTRs have zero economic cost in this benefit calculation but propose that the cost to TSOs of issuing LTTRs be netted off any estimated benefits as part of an overall cost-benefit analysis.

\(^{19}\) The actual quality of the various options will reflect the specifications of the transmission right and, for example, the extent to which payments may be limited in the event of outages on the corresponding cross-border cable.
Table 1: Implied reduction in bid-ask spread costs relative to hedging using baseload Nordic hedging products

<table>
<thead>
<tr>
<th>EUR/MWh</th>
<th>2019</th>
<th>2020</th>
<th>2021</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nordic system price contract plus NO2 EPAD</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Germany</td>
<td>0.75</td>
<td>0.69</td>
<td>0.72</td>
</tr>
<tr>
<td>Great Britain</td>
<td>0.66</td>
<td>0.69</td>
<td>0.59</td>
</tr>
<tr>
<td>Netherlands</td>
<td>0.55</td>
<td>0.47</td>
<td>0.46</td>
</tr>
<tr>
<td>Nordic system price contract only</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Germany</td>
<td>0.11</td>
<td>0.05</td>
<td>0.08</td>
</tr>
<tr>
<td>Great Britain</td>
<td>0.02</td>
<td>0.05</td>
<td>-0.05</td>
</tr>
<tr>
<td>Netherlands</td>
<td>-0.09</td>
<td>-0.17</td>
<td>-0.18</td>
</tr>
</tbody>
</table>

Source: THEMA calculations based on data from Nasdaq and the ACER Market Monitoring Report 2019

As discussed in section 7.1.1, although these potential savings reflect a reduction in the bid-ask costs borne by the hedger, they also reflect potential reductions to socio-economic costs, for example, in the form of lower costs to traders from managing inventories of illiquid products.

The bottom right cell tells us that hedgers wishing to hedge the Dutch power price might potentially have done so more cheaply by using a Nordic system price contract combined with a transmission right, provided they were also willing to take exposure in the spread between the NO2 and system price (since this cell assumes that no EPAD is used).

We can multiply these potential savings per MWh by the potential transfer capacities of each of the cables to establish the scale of the maximum potential reduction in hedging costs. Table 2 below shows the results of these calculations.

Table 2: Maximum potential hedging cost reductions implied by bid-ask spread and cable capacity data

<table>
<thead>
<tr>
<th>Million EUR</th>
<th>2019</th>
<th>2020</th>
<th>2021</th>
</tr>
</thead>
<tbody>
<tr>
<td>Including EPAD cost</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Germany</td>
<td>8.7</td>
<td>8.0</td>
<td>8.4</td>
</tr>
<tr>
<td>Great Britain</td>
<td>7.7</td>
<td>8.0</td>
<td>6.9</td>
</tr>
<tr>
<td>Netherlands</td>
<td>3.2</td>
<td>2.7</td>
<td>2.7</td>
</tr>
<tr>
<td>Excluding EPAD cost</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Germany</td>
<td>1.2</td>
<td>0.6</td>
<td>0.9</td>
</tr>
<tr>
<td>Great Britain</td>
<td>0.3</td>
<td>0.6</td>
<td>-0.6</td>
</tr>
<tr>
<td>Netherlands</td>
<td>-0.5</td>
<td>-1.0</td>
<td>-1.0</td>
</tr>
</tbody>
</table>

Note: Assumed capacities of NorNed 700 MW, NordLink 1400 MW and NSL 1400 MW with 95% of capacity sold as transmission rights

As can be seen, there is a significant difference in the results depending on whether or not we account for the assumed EPAD cost. This reflects the relatively high costs assumed for the costs of covering the NO2 area price risk and this is reflected in the assumed bid-ask spread for an NO2 EPAD. It is also important to stress that these numbers reflect an upper bound on the scale of benefits of this type. Specifically, we assume that all available transmission capacity is used to support reduced hedging costs through its use as a bridge to liquidity. We also assume that the economic costs reflected in the bid ask spread are variable and can therefore be avoided. If these
costs are fixed, reflecting the minimum costs of the trading infrastructure for example, they will not be avoided by marginal changes in the mix of products used.

The positive numbers reflect cost reductions achieved by substituting a relatively high-cost Nordic hedging solution with a lower-cost alternative constructed of products referenced against foreign price zones. Importantly, the negative numbers also reflect cost reductions, and therefore are socially beneficial, but, in these cases, reflect cost reductions achieved by substituting a relatively high-cost foreign hedging solution with a lower-cost alternative constructed using Nordic system price contracts. The smallest social benefits are therefore seen when there is small difference in hedging costs between the connected zones, as is reflected in similar bid-ask spreads between the relevant hedging products. In these cases, the small difference in liquidity between the markets limits the value of building a 'bridge to liquidity'. This is analogous to the value of interconnection being lower when it connects two bidding zones with very similar power prices.

The figures suggest that the greatest benefits are seen by providing a bridge to liquidity to the German market, given the relatively low bid-ask spreads and high liquidity of the German power market. This accords well with the fact that some Norwegian generators already construct hedges using German power futures.

7.2.3 Reduced barriers to entry
As described in section 7.1.1, transmission rights may reduce barriers to entry and support competition. Based our interviews with market stakeholders, it seems unlikely that existing actors in any of the connecting zones are actively considering expanding their operations across the borders connected by these cables. As such, we consider that any benefits associated with enhanced cross-border competition are likely to be negligible.

It is conceivable that transmission rights might enhance competition in the provision of NO2 area price hedging services and, by extension, the supply of fixed-price power contracts in this bidding zone. At present, generators with generation capacity in NO2 are the natural suppliers of NO2 area price hedging services to consumers in the bidding zone since they have the offsetting physical exposure. The introduction of transmission rights would allow a wider set of actors to offer to hedge NO2 area price risk, or to sell fixed-price contracts in NO2, and thereby potentially enhance competition in these areas. This argument is less relevant to the other zones due to the fact that exchange-traded products already exist to manage the relevant bidding zone price risk and because these zones are larger and therefore have less concentrated markets for local generation.

7.3 Estimates of costs and distributional impacts
In the sections below, we share our assessment of administrative costs and the distributional impact of systematic differences between auction revenues and congestion incomes. Firmness costs are not covered because, as explained in section 7.1.2, they do not give rise to a distinct, systematic change in either economic costs or the distribution of revenues as a result of issuing transmission rights.

7.3.1 Administrative costs
The issuance of transmission rights on the cables would inevitably impose some additional administrative costs, most notably on the TSOs involved in each of the cable projects. Chapter 4 of the European Guideline on Forward Capacity Allocation requires that the auctioning and settlement of transmission rights be conducted via a single allocation platform. This platform is the Joint Allocation Office (JAO). We assume that, were transmission rights to be issued on NordLink, NorNed or North Sea Link, the auctioning and settlement of these transmission rights would be administered by JAO, consistent with the requirements of the Guideline on Forward Capacity Allocation. JAO’s own administrative costs are socialised among the TSOs that it serves and so these TSOs would therefore be liable to contribute to JAO’s administrative costs.

The TSOs would also bear some administrative costs directly, most notably as the cost of staff time spent implementing and overseeing their operational relationship with JAO.
We have discussed the scale of the associated costs with Energinet, which currently issues transmission rights on their cross-zonal borders in the form of Financial Transmission Right options via JAO. They have suggested that Energinet’s contribution to JAO’s socialised costs amounts to approximately EUR 35,000 per year per border. Importantly, this cost assumes that Energinet is the responsible TSO on only one side of the relevant border and that the TSO for the other bidding zone is sharing the total costs. Where Energinet is the responsible TSO in both zones, Energinet’s approximate costs for the relevant border would therefore be around EUR 70,000 per year. This cost covers the administration of one annual and twelve monthly auctions for a product in both directions across the relevant border, as well as the subsequent settlement of contracts. We understand that some borders have additional auctions, e.g. for quarterly products, and that they bear a larger cost as a result.

The direct administrative costs to Energinet were considered to be on the order of 0–0.1 FTE staff member.

### 7.3.2 Costs of deviations in auction revenues

As noted in section 7.1.2, there may be a systematic difference between the revenues earned from the auctioning of transmission rights and the congestion income earned on cross-zonal capacity. This difference implies that the auctioning of such rights will alter the distribution of revenues between transmission rights holders and network tariff payers. It could also conceivably affect investment in cross-zonal capacity.

In this section, we look to understand the potential magnitude of the distributional impact. The investment impact is difficult to quantify and will depend on the extent to which investment decisions are influenced by these distributional effects and, if they are, the size of the effect for new cables. The latter will, of course, depend on whether or not transmission rights are made available for the relevant cables.

To ascertain the plausible range of possible mark-ups or discounts relative to expected congestion income, we have used data on historical auction prices for transmission rights from JAO. The dataset used covers transmission rights for delivery in the period 2011-2017. Not all products were auctioned or had data for the full period.

Our analysis suggests that lagged congestion incomes are a better predictor of auction prices than actual congestion incomes during the delivery period. In other words, auction prices for a transmission right for 2017 more closely reflect congestion income on the border in 2016, than in 2017. This makes intuitive sense since bidders are likely to place bids based on the most recent available data on price spreads and will not know the outturn congestion income at the time of the auction. We, therefore, use congestion incomes for the year before delivery (lagged congestion incomes) as a proxy for bidders’ expectations of congestion incomes in the delivery period.

Figure 7 below charts auction prices against lagged congestion incomes. Each dot reflects a specific auction result. The grey dashed line shows the line of equality – points on this line reflect auction prices that exactly equal lagged congestion income. Any points above this line reflect auction prices that are greater than lagged congestion income. Any points below this line reflect auction prices that are less than lagged congestion income.

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21 The calculation of average lagged congestion rent in a single direction was calculated based on the average price spread between the relevant zones bounded at zero (i.e. disallowing negative spreads). No adjustment was made for cable availability, consistent with firm transmission rights.

22 We have removed some results for auctions on rights to GB for which prices were likely affected by the British Levy Exemption Certificate scheme.
Figure 7 also includes two other lines. These make explicit our assumed upper and lower assumptions for the potential systematic mark-up or discount of auction prices relative to expected congestion income. These lines are simply assumptions, based on historic auction outcomes. They are not mathematically derived from the data but are intended to define reasonable upper and lower boundary cases consistent with the observed spread in past auction data. These assumptions enable us to calculate a possible range for the scale of the redistribution effect. It should be borne in mind that the data points shown do not represent data on actual mark-ups and discounts, since bidders’ price expectations are unknown. Furthermore, even if the past auction data did fully reflect the difference between price spread expectations and auction clearing prices, these past auctions may not be representative of bidding behaviour for transmission rights on the NordLink, NorNed and North Sea Link cables specifically.

**Figure 7: Historic auction prices relative to lagged congestion rent**

To estimate the total level of future congestion income, we have used data from our modelling analysis of future congestion income on NordLink, NorNed and North Sea Link. The modelled annual congestion income is shown in the table below as the baseline congestion income. When we calculate the overall effect on network tariffs, we also account for the level of congestion income on other interconnectors and between Norwegian bidding zones, as these are affected by the new interconnectors to Germany and the UK. In the modelling, we have assumed 95 per cent availability for the interconnectors, which is above the historical average for such cables based on data received from Statnett. However, this assumption only has an indirect effect on the results as the transmission rights are assumed to be firm and to pay out regardless of cable availability.

To estimate the auction revenues that would be received for each cable were transmission rights auctioned, we begin by scaling these baseline congestion incomes up to reflect the hypothetical average price spread across all hours, i.e. irrespective of whether the cable is available or not. This gives the implied annual pay-out to holders of firm FTR options. We have then divided through by the number of hours in a year to express this annual sum as an hourly average price spread that is consistent with the values on the x-axis in Figure 7 above. We then use the equations shown to convert these congestion income levels into an implied auction price. So, for example, if the average...
congestion income is calculated to be 10 €/MWh for a specific cable and direction (read on the x-axis), we assume that the relevant transmission right will receive a price in the range of 5–13 €/MWh as shown by the upper and lower (green and red) equations.

Assuming that 95% of cable capacity is auctioned and receives the auction price implied by these equations gives us an estimate of total auction revenue for the relevant direction. Summing the auction revenues for products in both directions gives an estimate of the total revenue earned from the auctioning of transmission rights that can be compared with the modelled congestion income earned on each cable.

Our modelling shows that the congestion income is likely to vary significantly over time and between years in addition to the inherently stochastic variations due to underlying market conditions. We therefore show the results for both 2022 and 2030 in the table below.

<table>
<thead>
<tr>
<th></th>
<th>2022</th>
<th>2030</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Baseline congestion income</td>
<td>LTTR auction revenue</td>
</tr>
<tr>
<td>NordLink</td>
<td>39</td>
<td>10</td>
</tr>
<tr>
<td>NSL</td>
<td>41</td>
<td>9</td>
</tr>
<tr>
<td>NorNed</td>
<td>20</td>
<td>4</td>
</tr>
<tr>
<td>Total</td>
<td>100</td>
<td>23</td>
</tr>
</tbody>
</table>

Source: THEMA power market model, JAO.
Note: Results may not sum due to rounding. ‘Baseline’ shows modelled congestion income assuming 95% availability.
Values in brackets show the difference relative to the baseline congestion income.

In the low scenario, the auction revenues will lie significantly below congestion income. In the high scenario, the auction revenues can turn out to be significantly higher than congestion income. This implies a significant redistribution of income between network tariff payers and the holders of transmission rights.

An obvious question is to what extent this distributional impact could be mitigated. In our discussions with Energinet, they told us that they had previously considered the possibility of reducing the capacity of transmission rights auctioned for those products where revenues appeared to be systematically lower than congestion incomes. One challenge to such an approach is identifying the affected products. Given the uncertainty of actual incomes, even if auction prices equal expected congestion incomes, there will inevitably be some instances in which revenues are lower than actual congestion incomes. More fundamentally, however, Energinet concluded that EU regulation may not allow for the restriction of auction volumes. Specifically, although reducing capacity in this way does not appear to be explicitly ruled out, they believe that the regulation implies that the long-term capacity calculation methodologies identified for each capacity calculation region should be used to determine the transmission capacity made available to the market through long-term transmission rights. Under this interpretation, TSOs only have control over how this capacity is divided between products, following Article 16 of the Forward Capacity Allocation Guidelines. We have not sought to provide a legal assessment of what is possible given current regulations.

We would however point out that, even if TSOs are themselves prevented from restricting the capacity that is auctioned, it might still be possible for network tariff payers to act collectively to prevent transmission rights from being sold at prices that they considered to be unacceptably low. In theory, network tariff payers could request that their tariffs fund minimum bids for transmission rights and that the income earned on any rights obtained in this way be used to reduce tariffs. As such, we suspect that some creative solutions to mitigate low auction revenues could be developed were this considered important as a means to mitigate unwanted distributional impacts as a result of issuing transmission rights.
7.3.3 Impact on tariffs

Under the Norwegian revenue regulation of Statnett, variations in congestion income are offset against tariffs.\(^{23}\) Any change to congestion income will therefore affect network tariffs with a short time delay through the regulatory account mechanism used to settle differences between actual and allowed revenues (with interest compensation). All variations in congestion income are borne by electricity consumers, as the tariffs for generators are already at the maximum level established in EU Regulation 838/2010.\(^{24}\) Of the cost factors discussed above, by far the most important in terms of its implications for tariffs is the potential systematic difference between auction revenues and congestion incomes. The administrative costs of issuing transmission rights are orders of magnitude smaller than the auction revenue effect and, as discussed in section 7.1.2, tariffs will be similarly affected by cable outages regardless of whether transmission rights are issued. In the following analysis, therefore, we look only at the tariff implications of the auction revenue effects discussed in the previous section.

To illustrate the impact of LTTR auction revenues on consumer tariffs we use 2022 and 2030 as our sample years. We use the 2020 consumption tariff, which amounted to 393 NOK/kW or 38.5 EUR/kW, as a proxy for the 2022 tariff and assume that this level has been set based on an expected congestion income equal to the baseline figure reported in Table 3 above. The 2021 tariff is significantly reduced due to the ongoing pandemic (but the shortfall will be recovered later), hence the 2020 level is more representative of Statnett’s current cost base and revenue cap. Note that large consumers (more than 15 MW and 100 GWh consumption) receive a discount of 50 per cent on the tariff rate. Consumption located at the same point of connection as generation can also get a reduction in the kW charging base of up to 40 per cent. Statnett’s total revenue cap in 2021 is just short of EUR 1000 million, most of which is covered by tariffs on consumers. For 2020, we assume a revenue cap of EUR 1000 million. For 2030, we inflate the 2022 revenue cap level using an annual growth rate of 2 per cent to simulate an expected growth in real terms due to high levels of investment. The consumption tariff is, however, assumed to be unchanged in real terms due to consumption growth in line with the assumptions in NVE’s long-term power market analysis from 2020. All calculations are done in real 2022 figures. We also assume a 10 per cent growth in income from generation due to investments in new generation at approximately the same level as assumed in NVE’s 2020 long-term power market analysis.

To calibrate the level of other congestion income, we have used our own modelling estimates for the different interconnectors including congestion income earned on internal Norwegian bidding zone borders. The congestion income on these interconnectors are affected by the new interconnectors to Germany and the UK and are relevant to considering the overall impact on tariffs.

Using data from Statnett’s annual report for 2019 on the distribution of tariff income between tariff components and customers, we assume that revenue from consumer tariffs will constitute around EUR 517 million in 2022 (including revenues that are deferred via the regulatory account). In 2030, the consumer tariff revenues increase to EUR 562 million with the expected congestion income.

Using the data and assumptions above, we illustrate the impact of systematic differences between auction revenues and congestion income on the total tariff bill for consumers and the general consumption tariff. The results shown in the table below report the impact from each of the three interconnectors individually and the total effect.

\(^{23}\) The regulatory process for approving use of congestion income follows the procedure set out in Article 19 of EU Regulation 2019/943, but the end result is that congestion income is offset against tariffs. Statnett is therefore not exposed to congestion income risk.

\(^{24}\) Energy charges and connection charges are not subject to this cap, but these charges are set on the basis of actual costs (marginal cost of losses and customer-specific investment costs respectively) and are not affected by variations in congestion income.
Table 4: Impact on Statnett revenues and relative change in consumption tariff under different scenarios for auction revenues. EUR million

<table>
<thead>
<tr>
<th>Interconnector</th>
<th>2022 Revenue impact</th>
<th>2022 Tariff impact</th>
<th>2030 Revenue impact</th>
<th>2030 Tariff impact</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Low</td>
<td>High</td>
<td>Low</td>
<td>High</td>
</tr>
<tr>
<td>NordLink</td>
<td>-29</td>
<td>+32</td>
<td>+5.7%</td>
<td>-6.1%</td>
</tr>
<tr>
<td>NSL</td>
<td>-32</td>
<td>+31</td>
<td>+6.2%</td>
<td>-6.1%</td>
</tr>
<tr>
<td>NorNed</td>
<td>-16</td>
<td>+16</td>
<td>+3.0%</td>
<td>-3.0%</td>
</tr>
<tr>
<td>Total</td>
<td>-77</td>
<td>+79</td>
<td>+14.9%</td>
<td>-15.2%</td>
</tr>
</tbody>
</table>

Source: THEMA power market model, Statnett. Rounding errors may occur.

Table 4 shows that the average consumption tariff could increase by 15-16 per cent in 2022 and 2030 under the low scenario for auction revenues. Conversely, under the high scenario for auction revenues, tariffs are reduced by about 13-15 per cent. These estimates refer to the auction revenues for all three interconnectors in total.

It is worth noting that issuing transmission rights will potentially impact not just the average level of tariffs, but also their volatility. Tariffs are fairly directly affected by price developments, due to the link with congestion income. In 2020, for example, Norwegian prices were atypically low and gave rise to record-high congestion incomes. This income will help depress future tariffs. As such, Norwegian consumers are likely to get a windfall both from lower prices and then lower tariffs. However, the opposite may also occur. Namely, years with unexpectedly high prices may also imply low congestion income and therefore higher network tariff in later periods. Auction revenues should, in theory, be more stable and predictable than actual congestion incomes. Consequently, issuing transmission rights should also result in more stable network tariffs than otherwise.

### 7.4 Liquidity impacts

It is clear that the introduction of transmission rights has the potential to affect the use and liquidity of other hedging products. Here we distinguish between two distinct and potentially opposing liquidity effects.

The first of these effects is the result of the use of transmission rights as a bridge to liquidity. It is also, seemingly, one of the most significant concerns that Norwegian market participants have with regard to the issuance of transmission rights on the cables. The core idea behind transmission rights as a bridge to liquidity is that these rights help market participants to substitute low-liquidity, high-cost hedging products in one zone with high-liquidity, low-cost products in a connected zone. This is clearly directly beneficial to the party making this substitution, assuming the transmission right itself is not overly costly. However, it also affects the products involved. Specifically, this substitution implies that the low-liquidity product may become even less liquid, while the high-liquidity product becomes more liquid.

As discussed in section 7.2.2, the distribution of bid-ask spreads and availability of hedging products in the various markets suggests to us that NO2 is more likely to be the low-liquidity market, as described above, if hedgers use transmission rights as a bridge to liquidity. As such, hedgers will be substituting Nordic products with, for example, German futures. This may harm the liquidity of Nordic products, but improve the liquidity of German ones.

It is worth noting that this assumes that the issuance of transmission rights triggers the substitution of these products. To the extent this substitution has already occurred, there will be no further effect on liquidity, but there may still be some benefit through the provision of a useful hedging tool. Some stakeholders noted that foreign power futures are already being used to help hedge Nordic power price exposures. It is also worth noting that the relative importance of these impacts may not be symmetric, since the same absolute loss of trading in an illiquid market may appear to have a larger relative effect than its addition to a much more liquid market.

It is difficult to know how meaningful this impact would be in practice. At the Nordic system level, daily traded volumes are on the order of 2–6 TWh. In comparison, the maximum daily transmission capacity on NordLink will be 0.03 TWh. This suggests that the practical implications at a Nordic
system level, which already benefits from liquidity pooling, might be rather limited. The effects on NO2 hedging products would presumably be more pronounced. However, the current users of these products will be exactly those market participants that should benefit directly from the substitution away from the current low-liquidity alternatives. Competition between existing products, for example OTC NO2 EPADs, and alternative hedges that make use of the transmission rights, may also help to ensure that costs for local products do not rise excessively despite worsening liquidity.

The second effect on the liquidity of other hedging products is the result of trading activity, rather than hedging directly. Here, we can imagine that a trader acquires a transmission right with a view to offsetting the resulting exposure, at a profit, using a variety of other products. In this case, it is clear to see that the issuance of transmission rights will support the liquidity of the other products used to offset the transmission right. Here we can imagine traders seeking to use system price contracts, and possibly OTC NO2 EPADs, as a means to offset the resulting exposure. As discussed, earlier, the desire to trade NO2 EPADs may even encourage efforts to support their trading via the exchange.

7.5 Conclusions

In this section, we bring together the consideration of various potential impacts to make more explicit the reasons for and against issuing transmission rights on the NordLink, NorNed and North Sea Link cables.

The main benefit of issuing such rights is that doing so has the potential to improve hedging opportunities for market participants. There are two mechanisms by which these opportunities might be improved. Either those participants who wish to hedge use the transmission rights as a bridge to liquidity, effectively hedging in a different market using different products, or transmission rights stimulate additional trade activity by energy trading companies, adding to the liquidity of hedging products anyway used by fundamental hedgers. Transmission rights can be used for either purpose.

It is hard to forecast how such rights will come to be used in practice. Our interviews with market participants suggest to us that relatively few market participants will have a direct interest in conducting sophisticated hedges using transmission rights and hedging products in a foreign market. In addition, the use of transmission right options – the default transmission right product – may effectively preclude a bridge to liquidity strategy when trading against a predominant price difference. As a result, we suspect that trading companies may purchase a significant proportion of transmission rights issued. If true, this would tend to imply that the benefits to hedging opportunities come about primarily as a result of increased liquidity in the trading of other hedging products.

At least some of this benefit may be realised by increased liquidity in Nordic system price products. However, we suspect that any change would be relatively small. As noted above, the volume of transmission capacity is small in comparison with the volume of system price contracts already traded. It is also possible that the greater liquidity brought by the activity of trading companies is at least partially offset by market participants (in NO2) choosing to hedge in foreign markets.

The effect on the liquidity of NO2 area price hedging instruments is likely to be more important. The lack of an NO2 EPAD means that it will be difficult for international trading companies to improve the liquidity of NO2 area price hedging specifically. However, the availability of transmission rights will open up a greater number of potential providers of over-the-counter EPADs or of NO2 area price hedging services more generally. It may also allow existing providers of NO2 area price hedging services to reduce their costs, by effectively offering bridge-to-liquidity hedging as a service. This could potentially increase competition and result in a better product offering and lower cost hedging options for fundamental hedgers looking to hedge NO2 area price risk.

As was noted in one of the interviews, the existence of an NO2 EPAD would provide a mechanism by which trading companies that purchase transmission rights can trade their NO2 price exposure. This would provide a more direct route by which their activities could support liquidity and therefore hedging opportunities. It makes sense, therefore, to consider the issuance of transmission rights on these cables alongside the viability of an NO2 EPAD product.
In addition to this principal benefit, transmission rights may improve the transparency of forward market prices for NO2. However, this effect is unlikely to be very significant since the implied NO2 price must be derived from the price of the transmission right itself. Market participants that are sophisticated enough to do this may well be able to make other inferences about market price expectations.

Against these potential benefits, the issuing of transmission rights would imply a direct administrative cost to the TSOs involved. Based on Energinet’s experience, these costs are likely to be on the order of EUR 35,000 per year per border for each TSO involved, as well as require the time of 0–0.1 FTE. This administrative cost reflects the economic costs associated with issuing transmission rights.

Far larger than these economic costs, however, are the potential distributional consequences of issuing transmission rights. The value that bidders place on transmission rights may be greater or less than the value of the expected payments received due to the effect on each bidder’s overall risk exposure. As such, even in a competitive auction, there may be a systematic difference between auction revenues and congestion incomes. This implies that compelling the TSO to issue transmission rights may result in a systematic change in the revenues earned from a cable. These changes are not an economic cost, but instead reflect differences in the distribution of revenues between the TSO and transmission rights holders. Ultimately this distributional impact, which could go in either direction, is likely to affect consumer network tariffs in Norway.

Overall, therefore, a decision on whether to issue transmission rights is likely to turn on the extent to which potential improvements to hedging opportunities, particularly in NO2, can be justified against the possible risk to consumer network tariffs. It will therefore be relevant to consider to what extent the potential benefits can be maximised, for example through the creation of an exchange-traded NO2 EPAD, and the risks mitigated, for example through the implementation of an effective reserve price for transmission rights.
APPENDIX 1 – NORDREG METRICS

In this appendix, we present metrics on hedging opportunities in the bidding zones for NO2, the Netherlands, Germany and Great Britain. The metrics presented largely relate to those specified in the NordREG Methodology and cover open interest, the trading horizon, traded volumes, bid-ask spreads, churn rates, ex-post risk premia and the correlation between various prices.

Different data sources have been used for the different bidding zones. For the NO2 bidding zone, data on the Nordic market received from Nasdaq have been used. Due to the lack of NO2-specific data, we present metrics calculated on either an all-Nordic basis or for neighbouring bidding zones. For Great Britain, publicly available data from Ofgem, the British National Regulatory Authority, has been used.

For the Netherlands and Germany, a lack of reliable data has limited the assessment. Some metrics for these countries been excluded from this section of the report due to concerns about the reliability of the underlying data. Where the reliability of the data is questionable, we have not used this data to inform the overall conclusions of this report. The results are still provided however in a second appendix.

Open interest

Open interest refers to the total size of open positions with a clearing house at a given point in time. When a market participant wishes to hedge a physical exposure to the power price using financial derivatives, they will create an open position for the relevant contract and keep this position until delivery. When a speculator trades such contracts, he or she will typically open a position by buying or selling the relevant contract and then close this position at a later point by making an offsetting trade. For example, they will try to buy the contract when priced low and then sell it at a higher price. As such, information on the size, distribution and dynamics of open interest can be used to infer the volume of physical exposures that are being hedged and the composition of products used to construct these hedges.

For individual contracts, there will typically be a steady increase in open interest from the beginning of the trading period until the last trading day before delivery. This occurs as hedges are built up over time. Just ahead of delivery there is a sudden drop in open interest caused by cascading, the process by which open positions in a specific contract are transformed into open positions in shorter contracts covering the same delivery period. For example, open positions in a yearly contract are transformed into open positions in four quarterly contracts. The resulting drop in open interest in the yearly contract is therefore perfectly offset by the increase in open interest for quarterly contracts.

Figure 8 presents total open interest (TWh) for all Nordic system price contracts for the time period included in the sample (04.03.2012 – 31.08.2020). Separate lines are shown for monthly, quarterly and yearly contracts.25

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25 Open interest for weekly contracts is low relative to other durations. The line for weekly contracts is therefore excluded from the figure, but the numbers are included in the total line.
The figure shows that the bulk of open interest in Nordic system price contracts is established in yearly contracts. It also shows that total open interest was stable from around 2013 to 2018, but there is a notable decline from the start of 2019. This decline suggests that the volume of exposures being hedged may have fallen.

Our work examining hedging strategies suggests that generators may adjust the share of their total exposures that they hedge based on their view of market fundamentals and the perceived downside risk. As such, they may reduce the volume of exposures hedged where they have little reason to fear lower prices. To examine whether price levels might have played a role in the decline in total open interest observed, Figure 9 shows total open interest against the settlement price of the front-year (Y+1) futures contract. In interpreting this chart, it is important to bear in mind that the direction of causality may also run the other way, with a lack of hedging demand depressing the price of futures contracts.
Prices for the 2020 contract were indeed much lower than those of the 2019 contract at the end of 2018, as shown by the significant drop in front-year prices at the start of 2019, i.e. when the front-year changes from 2019 to 2020. However, the prices of the 2020 contract, at just under 40 EUR/MWh were not low compared to prices in earlier years. As such, it appears that low-price expectations alone are probably not responsible for the reduction in open interest from 2019.

Figure 10 shows for any given delivery date the open interest (MW) in Nordic system price contracts covering that date one month ahead, one quarter ahead and one year ahead of time. Thus, the line covering open interest one quarter ahead might include open interest from a combination of yearly, quarterly and monthly contracts with delivery periods covering the relevant date. Looking at the relative heights of the different lines helps to provide a sense of how far ahead the market is hedging, in aggregate, and how the composition of hedging is changing. The results show that open interest builds from a year out to a quarter out, suggesting that the market is still building up the hedge within-year. However, by a quarter ahead of delivery, most of the volume that is to be hedged will have been hedged.

**Figure 10: Open interest (MW), Nordic system price contracts, 1 year, quarter and month ahead, by delivery date**

![Graph](image)

*Data source: Nasdaq*

Figure 11 shows open interest (TWh) for EPAD contracts for all bidding zones. Total open interest in EPAD contracts has been stable throughout the studied period. There is even a slight increase in the use of EPADs in 2020. This may reflect higher perceived area price risk – 2020 was marked by large water reserves in Norway and limited transmission capacity between Norway and Sweden due to transmission outages.
In Figure 12, we replicate the approach used for Figure 10 to show total open interest for a future delivery date but for EPADs. The figure shows open interest (MW) in EPADs for all bidding zones and all contracts with a delivery period one month ahead, one quarter ahead and one year ahead of time. The relatively large volumes of month-ahead open interest, especially in contrast to quarter-ahead interest, in 2020 may indicate that the market was becoming increasingly concerned about the need to manage area price risk in the few months ahead of delivery.

In the absence of an NO2-specific EPAD, we have also look at developments in the neighbouring NO1 bidding zone. Figure 13 shows open interest (TWh) for EPAD contracts for NO1 (Oslo). Over the last two years, there has been a noticeable increase in open interest for the NO1 EPAD. Most of this increase has been in yearly contracts.
Open interest in relation to physical consumption

By dividing open interest by physical consumption, we can get an indication of the share of physical consumption that is hedged in the futures market. Figure 14 shows, for monthly, quarterly and yearly contracts, the open interest recorded for the contract shortly prior to delivery divided by total physical consumption in the relevant delivery period. Note that since yearly contracts cascade into quarterly contracts etc., total open interest tends to grow as we move from longer to shorter contracts. The results show that this measure has remained stable throughout the studied time period, at around 0.2–0.4. Again, this suggests that Nordic system price futures hedge something like 20–40% of physical consumption in the Nordics.

Trading horizon

The trading horizon is a descriptive measure and sets out the different listed series that can be traded and cleared on the exchange. This describes the technical hedging opportunities that exist via exchange-based derivatives.
Figure 15 shows the trading horizon for different contract types on Nasdaq, including EPADs and Nordic system contracts.

**Figure 15: Trading horizon for different contract types, EPADs and Nordic system contracts**

<table>
<thead>
<tr>
<th>Week¹</th>
<th>Future</th>
<th>EPADs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Month²</td>
<td>Future</td>
<td></td>
</tr>
<tr>
<td></td>
<td>DS Future</td>
<td></td>
</tr>
<tr>
<td>Quarter³</td>
<td>Future/</td>
<td>Nordic system contracts</td>
</tr>
<tr>
<td></td>
<td>DS Future</td>
<td></td>
</tr>
<tr>
<td>Year⁴</td>
<td>Future/</td>
<td></td>
</tr>
<tr>
<td></td>
<td>DS Future</td>
<td></td>
</tr>
</tbody>
</table>

Notes:
1. Weekly EPADs exist only for Swedish and Finnish bidding zones.
2. Monthly Futures have three listed series for Norwegian, Danish, Estonian and Latvian areas and four listed series for Swedish and Finnish areas; Monthly DS Futures have two listed series for Norwegian, Danish, Estonian and Latvian areas and four series listed for Swedish and Finnish areas.
3. Both quarterly contract types have three series listed for Norwegian, Danish, Estonian and Latvian areas and four series listed for Swedish and Finnish areas.
4. Both yearly contract types have three series listed for Norwegian, Danish, Estonian and Latvian areas, two series listed for Latvian areas and four series listed for Swedish and Finnish areas.
5. The number of concurrently listed quarterly futures varies from eight to eleven, shown here by the striped area. The reason for this variation is that the quarterly contracts are added for one year (four quarters) at a time. There are always series listed for the next two years (eight quarters) and, in the first quarter of the year, a new full third year is added to the listed series, making eleven series (two years and three quarters) in total.

**Traded volumes**

Traded volumes show the number of MWh bought and sold during a specific period. Larger volumes will tend to indicate more active trade and suggest that the market for the relevant product is more liquid.

Figure 16 shows daily traded volumes (TWh) for monthly, quarterly and yearly Nordic system price contracts. Note that the traded volumes are averaged over a rolling time window of 45 days, backward from the date shown, so as to make trends easier to see. The traded volumes shown have been compiled using end-of-day totals covering the time period 04.01.2010-22.10.20. The traded volumes in the end-of-day data include exchange-traded volumes only, and will therefore not include cleared over-the-counter volumes.

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26 Futures contracts refer to contracts with daily (mark-to-marked) settlement against the closing price during the trading period. For Deferred Settlement (DS) Futures, there is no settlement during the trading period, and the (mark-to-market) settlement accumulates throughout the trading period, and then is realized in the delivery period.

27 Total traded volumes of weekly contracts are low relative to other durations and are therefore excluded from the figure. Total traded volumes of weekly contracts are included in the total line.
The results show total daily traded volumes in Nordic system price contracts to be in the range of 2–6 TWh. Total volumes appeared to increase between 2014 to 2017 and to have fallen back in recent years. Most of the traded volumes concern the trade of quarterly and yearly contracts, implying that these contracts are more liquid than monthly contracts.

**Figure 16: Traded volumes (TWh) Nordic system**

![Graph showing traded volumes (TWh) in the Nordic system. Data source: Nasdaq. Note: The traded volumes are averaged over a rolling time window of 45 days, backward.]

**Figure 17: Daily traded volumes (TWh) of EPADs (all bidding zones)**

![Graph showing daily traded volumes (TWh) of EPADs for all bidding zones. Data source: Nasdaq. Note: The traded volumes are averaged over a rolling time window of 45 days, backward.]

Figure 18 shows daily traded volumes (TWh) for the NO1 (Oslo) EPAD for monthly, quarterly and yearly contracts. Traded volumes pick up in 2020. This mirrors the up-tick observed in open interest and suggests that greater volumes are being hedged using the NO1 EPAD. The relatively large increase in the trading of quarterly EPADs at the start of 2020 may reflect the loss of more than half of southern Norway’s export capacity after an anchor damaged the Outer Oslo fjord connection in mid-February. This significantly reduced transmission capacity from eastern Norway to central Sweden (NO3) and contributed to atypically low prices in NO1.

![Graph showing daily traded volumes (TWh) for the NO1 EPAD. Data source: Nasdaq. Note: The traded volumes are averaged over a rolling time window of 45 days, backward. There was a re-organisation of the markets in 2013. Early Contracts for Differences were renamed EPADs.]

There was a re-organisation of the markets in 2013. Early Contracts for Differences were renamed EPADs.
Figure 18: Traded volumes (TWh) of NO1 (Oslo) EPAD

Data source: Nasdaq
Note: The traded volumes are averaged over a rolling time window of 45 days, backward.

Traded volumes in relation to physical consumption/Churn rate

The ratio between total traded volumes and total electricity consumption gives the churn rate. This provides an indication of how many times a MWh of power is traded before it is delivered to the final consumer.

Figure 19 shows, for each date, the daily traded volumes in Nordic system contracts in relation to daily physical consumption in the Nordic system.28 The figure shows a decline in the churn rate over the last six years, reaching a level of around 2 in 2019.

Figure 19: Traded volumes in relation to physical consumption (Churn rate), Nordic system

Data source: Nasdaq; Nord Pool
Note: The churn rate is averaged over a rolling time window of 120 days, backward.

Figure 20 shows daily traded volumes in EPAD contracts (all bidding zones) in relation to daily physical consumption in the Nordic price areas. There is no obvious trend in the churn rate of all EPADs, which has held steady at roughly 0.4 to 0.6 over the last six years.

Figure 20: Traded volumes in relation to physical consumption (Churn rate), Nordic EPADs

Data source: Nasdaq; Nord Pool
Note: The churn rate is averaged over a rolling time window of 120 days, backward.

Note that, strictly speaking, the volumes traded will be for different delivery periods with levels of consumption that are different from the date on which the trades occur. As such, it only makes sense to look at broad changes over time.
Figure 20: Traded volumes in relation to physical consumption (Churn rate), EPADs (all)

Data source: Nasdaq; Nord Pool
Note: The churn rate is averages over a rolling time window of 120 days, backward.

Figure 21 shows the daily traded volumes in each Norwegian EPAD contract in relation to daily physical consumption in that bidding zone. As can be seen, these EPADs have churn ratios that are relatively low in comparison to the all-EPAD equivalent, implying relatively low volumes of trade given the level of consumption in the zone.

Figure 21: Traded volumes in relation to physical consumption (Churn rate), EPADs

Data source: Nasdaq; Nord Pool
Note: The churn rates are averaged over a rolling time window of 120 days, backward.

Bid-ask spreads

The bid-ask spreads are calculated using data on daily best bids and best asks for each traded contract. The data contained a number of seemingly spurious zero values. To remove these datapoints from the results, days with non-positive best bids or non-positive best asks are filtered out of the dataset and are not included in the calculations.29

Figure 22 to Figure 26 show the absolute bid-ask spread for all Nordic system price futures and DS futures. For each date within each contract category (daily, weekly, monthly, quarterly and yearly contracts), the data is averaged over all traded contracts (with varying time to delivery). Then, for the remaining dates with no trading, spreads are inferred by (linear) interpolation. These figures show the daily bid-ask spreads averaged over a (backward) rolling time window of 30 days.

*Note that although this filter could conceivably remove (valid) datapoints with two non-zero values, all the removed datapoints contain at least one zero or blank entry.*
Figure 22: Absolute bid-ask spread, Nordic yearly power futures (EUR)

Figure 23: Absolute bid-ask spread, Nordic quarterly power futures (EUR)

Figure 24: Absolute bid-ask spread, Nordic monthly power futures (EUR)
Figure 25: Absolute bid-ask spread, Nordic weekly power futures (EUR)

Figure 26: Absolute bid-ask spread, Nordic daily power futures (EUR)

Figure 27 to Figure 29 show the absolute bid-ask spreads for the Norwegian, Swedish, Danish, and Finnish EPAD contracts. Similar to the power base futures, the bid-ask spreads are averages over all contract types and linearly interpolated for days without trading. The results shown in these figures are averaged over a (backward) rolling time window of 30 days. For the quarterly and monthly contracts shown in Figure 28 and Figure 29, a spike in spreads can be observed in the first quarter of 2020 for the Swedish and Finnish prices areas. Prior to this event, the spreads in the Swedish and Finnish zones seem, for most part, but with a few exceptions, to be capped at 1.0 EUR/MWh. It may be that limits on the acceptable bid-ask spread for the market maker were relaxed at this point due to the stress placed on the Nordic system in 2020 by the combination of a record-high hydrological balance in Norway and limited transmission capacity between Norway and Sweden due to outages. The traded volume of Norwegian EPAD contracts is low, and no data prior to May 2019 is available. Table 5 shows some summary statistics for Nordic Power contracts and selected EPAD contracts. It can be seen that the number of data points available for the OSL EPAD contracts are significantly lower than all Swedish and Danish EPAD contracts.
Figure 27: Absolute bid-ask spread, EPAD yearly contracts

Figure 28: Absolute bid-ask spread, EPAD quarterly contracts

Figure 29: Absolute bid-ask spread, EPAD monthly contracts
Table 5 Bid-Ask spread summary statistics for selected Nordic Power contracts and selected EPAD contracts

<table>
<thead>
<tr>
<th>Main Category</th>
<th>EPAD area</th>
<th>count</th>
<th>mean</th>
<th>std</th>
<th>min</th>
<th>25 %</th>
<th>50 %</th>
<th>75 %</th>
<th>max</th>
</tr>
</thead>
<tbody>
<tr>
<td>Power Base</td>
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<td>0.5207</td>
<td>0.6479</td>
<td>0.01</td>
<td>0.12</td>
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<td>0.65</td>
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</tr>
<tr>
<td>Power EPAD</td>
<td>ARH</td>
<td>1298</td>
<td>0.7678</td>
<td>0.3428</td>
<td>0.05</td>
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<td>0.95</td>
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</tr>
<tr>
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<td></td>
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<td>0.6</td>
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<td>2.1</td>
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<td>0.05</td>
<td>0.75</td>
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<td>1</td>
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<td>0.476</td>
<td>0.09</td>
<td>0.225</td>
<td>0.95</td>
<td>1.1</td>
<td>1.8</td>
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<td>4.4832</td>
<td>1.4061</td>
<td>0.75</td>
<td>3.275</td>
<td>4.5</td>
<td>6</td>
<td>6.5</td>
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<td>0.3491</td>
<td>0.05</td>
<td>0.2</td>
<td>0.5</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>TAL</td>
<td>6</td>
<td>6.3833</td>
<td>1.4905</td>
<td>4.7</td>
<td>5.1</td>
<td>6.35</td>
<td>7.75</td>
<td>8</td>
</tr>
</tbody>
</table>

Figure 30 and Figure 31 show bid-ask spreads vs. time to delivery for each type of contract. The x-axis shows the days until the delivery period starts. In each figure the hue indicates different relative contracts. So, for example, the chart for yearly contracts shows bid-ask spreads for the next delivery year (Y+1) as light teal at the far left of the chart. By definition, Y+1 contracts are traded between 1 and 365 days ahead of delivery. The next colour from the left shows the bid-ask spreads for Y+2 contracts and so on. The same logic applies for different contract durations. For example, the chart for weekly contracts shows the bid-ask spread for W+1 contracts in one colour, W+2 in another and so on. The solid dark lines indicate the median value, whilst the lighter shaded region indicates an estimated 95% confidence interval.

We would expect bid-ask spreads to be driven, at least in part, by uncertainty as to the spread between area and system prices. Assuming this uncertainty diminishes closer to delivery, we would expect the bid-ask spread to narrow. However, this pattern is not clearly visible for most of the contract durations below.
Figure 30: Bid-ask spread vs. time to delivery for Nordic power futures
Figure 31: Bid-ask spread vs. time to delivery for EPAD contracts
Ex-post risk premiums

One way of investigating any systematic biases in the pricing of power derivatives contracts is to calculate ex-post risk premiums. The ex-post risk premium for any contract is simply the difference between the contract’s price and the spot price during its delivery period. By looking at these premia over time, we can see if there is a systematic difference between these two prices. The ex-post risk premium can be interpreted as a mark-up or reduction on the price of power that must be borne by traders, suppliers or consumers, in order to hold the price risk. Any such mark-up or discount may reflect the willingness of risk-averse market participants to pay (accept) a risk premium (discount) for transferring the price risk. However, it could also denote inefficiency in the market. From the available data and empirical analysis, we cannot distinguish the two directly.

It is important to note that there will typically be a difference between the value of a futures contract and resultant spot prices that is due purely to forecasting error. This error is captured in the calculated ex-post risk premia. As such, we can only infer the size of any ex-ante risk premium by looking at the ex-post premia over time and assuming that forecasting errors are not systematically different from zero.

To test whether the ex-post risk premia are different from zero, i.e. whether there is a systematic mark-up or reduction in prices, we use a t-test. Statistically significant results suggest that futures prices appear to be systematically different from the underlying spot prices during the delivery period.

The results from these t-tests are shown below. The ex-post risk premia for system price futures are calculated as the difference between the contract price on the last trading day before the delivery period and the average spot price over the delivery period. For the EPAD-contracts, we use the difference between the contract price on the last trading day before the delivery period and the average spread between the system price and the area price over the delivery period. We have tested whether these premia are significantly different from zero in either direction.

None of the tests show ex-post risk premia that are significantly different from zero, suggesting that contract prices are a reflection of the underlying reference price and do not contain a mark-up or discount to expectations of the underlying reference price.

We have done tests for autocorrelation with Durbin Watson statistics. Some of the contracts had significant autocorrelation at a five percent level of significance. As such, some of the OLS estimates below may biased, however the conclusion of no significant results should be robust.

**Table 6: Ex-post risk premiums, monthly contracts**

<table>
<thead>
<tr>
<th>Area</th>
<th>Obs.</th>
<th>Mean</th>
<th>Min</th>
<th>Max</th>
<th>Std. Dev</th>
<th>t stat</th>
<th>t crit (5%)</th>
<th>p value</th>
<th>Significant 5% level</th>
<th>95% CI lower</th>
<th>95% CI upper</th>
</tr>
</thead>
<tbody>
<tr>
<td>System DS</td>
<td>129</td>
<td>0.83</td>
<td>-19.65</td>
<td>25.53</td>
<td>5.12</td>
<td>1.84</td>
<td>1.98</td>
<td>0.07</td>
<td>No</td>
<td>-0.06</td>
<td>1.72</td>
</tr>
<tr>
<td>System non-DS</td>
<td>61</td>
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<td>2.00</td>
<td>0.45</td>
<td>No</td>
<td>-0.61</td>
<td>1.35</td>
</tr>
<tr>
<td>Oslo DS</td>
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<td>-2.80</td>
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<td>0.34</td>
</tr>
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<td>0.17</td>
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<td>Trheim non DS</td>
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<td>3.10</td>
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<td>No</td>
<td>-0.51</td>
<td>1.06</td>
</tr>
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<td>0.12</td>
</tr>
<tr>
<td>Tromsø non-DS</td>
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<td>1.85</td>
<td>1.76</td>
<td>2.00</td>
<td>0.08</td>
<td>No</td>
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<td>0.06</td>
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</table>

*Data source: Nasdaq*
### Table 7: Ex-post risk premium, quarterly contracts

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<th>Min</th>
<th>Max</th>
<th>Std. Dev</th>
<th>t stat</th>
<th>p value</th>
<th>Significant 5% level</th>
<th>95% CI lower</th>
<th>95% CI upper</th>
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</thead>
<tbody>
<tr>
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<td>No</td>
<td>3.31</td>
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</tr>
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</tr>
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<td>4.29</td>
<td>1.84</td>
<td>0.09</td>
<td>2.05</td>
<td>0.93</td>
<td>No</td>
<td>0.65</td>
</tr>
<tr>
<td>Tromsø non-DS</td>
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<td>0.01</td>
<td>-2.51</td>
<td>4.29</td>
<td>1.90</td>
<td>0.02</td>
<td>2.09</td>
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</table>

**Data source:** Nasdaq

### Table 8: Ex-post risk premium, yearly contracts

<table>
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<tr>
<th>Area</th>
<th>Obs.</th>
<th>Mean</th>
<th>Min</th>
<th>Max</th>
<th>Std. Dev</th>
<th>t stat</th>
<th>p value</th>
<th>Significant 5% level</th>
<th>95% CI lower</th>
<th>95% CI upper</th>
</tr>
</thead>
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</tr>
<tr>
<td>System non-DS</td>
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<td>-4.86</td>
<td>-18.56</td>
<td>8.29</td>
<td>11.35</td>
<td>0.86</td>
<td>3.18</td>
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<td>No</td>
<td>13.20</td>
</tr>
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<td>Oslo DS</td>
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<td>-0.41</td>
<td>3.13</td>
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<td>1.64</td>
<td>2.36</td>
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<td>No</td>
<td>1.75</td>
</tr>
<tr>
<td>Oslo Non-DS</td>
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<td>-0.41</td>
<td>0.42</td>
<td>0.35</td>
<td>0.39</td>
<td>3.18</td>
<td>0.72</td>
<td>No</td>
<td>0.50</td>
</tr>
<tr>
<td>Tromsø DS</td>
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<td>-1.78</td>
<td>1.65</td>
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<td>Tromsø non-DS</td>
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<td>1.25</td>
<td>0.48</td>
<td>3.18</td>
<td>0.67</td>
<td>No</td>
<td>2.29</td>
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</tbody>
</table>

**Data source:** Nasdaq

Figure 32 below shows the distribution of ex-post risk premia in the form of histograms with observation counts on the y-axis and premia in EUR/MWh on the x-axis.
Figure 32: Ex-post risk premium, Monthly contracts

Data source: Nasdaq
Correlation

The correlation analysis below helps to show the extent to which different instruments represent reasonable proxies for hedging exposure to a specific power price. Thus, we can get a sense of to what extent one can hedge NO2 price risk using an NO1 EPAD or a German system price future by examining the correlation between the NO2 price and the prices referenced by these potential proxies. Good proxy hedges provide market participants with additional opportunities to hedge power price risk.

Table 9 shows the correlation of calendar-month-average spot prices. It covers the Norwegian bidding zones, the Nordic System price, Germany, Great Britain and the Netherlands for the period 01.01.2015 to 31.11.2020. The use of monthly average prices reflects an assumption that market participants are not concerned about deviations in prices over shorter periods and will therefore be satisfied if prices are well correlated from month to month.30

It is critical to note that this analysis is exclusively backward-looking and limited to the stated period between 2015 and 2020. It is entirely possible that changes in pricing dynamics brought about by the commissioning of new interconnectors and the development of new generation capacity will alter the extent of price correlation between zones in the future.

The results show a high degree of correlation between prices in the Norwegian bidding zones and the Nordic system price. Indeed, there appears to be perfect correlation between NO1, NO2 and NO5 monthly average prices.

These results suggest that a market participant wishing to hedge an overall NO2 price exposure could have constructed a good hedge using either a system price future, or a system price future complemented with an NO1 EPAD. As such, the lack of an exchange-listed NO2 EPAD is unlikely, in itself, to have seriously harmed market participants ability to hedge NO2 price risk during this period.

The correlation between the Nordic prices and those in the German, British and Dutch bidding zones is significantly lower, at around 0.6-0.7.

Dutch prices are reasonably strongly correlated (0.9) with those in both the German and British bidding zones.

Table 9: Correlation, monthly average spot, last five years

<table>
<thead>
<tr>
<th></th>
<th>NO1</th>
<th>NO2</th>
<th>NO3</th>
<th>NO4</th>
<th>NO5</th>
<th>SYS</th>
<th>GER</th>
<th>GB</th>
<th>NED</th>
</tr>
</thead>
<tbody>
<tr>
<td>NO1</td>
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<td></td>
<td></td>
<td></td>
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<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NO3</td>
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<td>0.99</td>
<td>1.00</td>
<td></td>
<td></td>
<td></td>
<td></td>
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<td></td>
</tr>
<tr>
<td>NO4</td>
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<td>0.98</td>
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<td>1.00</td>
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<td></td>
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<td></td>
<td></td>
</tr>
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<td>NO5</td>
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<td></td>
<td></td>
<td></td>
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<tr>
<td>SYS</td>
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<td>0.99</td>
<td>0.98</td>
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<td>0.65</td>
<td>0.64</td>
<td>0.65</td>
<td>0.68</td>
<td>1.00</td>
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</tr>
<tr>
<td>GB</td>
<td>0.67</td>
<td>0.67</td>
<td>0.68</td>
<td>0.66</td>
<td>0.66</td>
<td>0.68</td>
<td>0.73</td>
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<tr>
<td>NED</td>
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<td>0.74</td>
<td>0.90</td>
<td>0.90</td>
<td>1.00</td>
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</tbody>
</table>

Source: THEMA calculations, Montel data

30 See section 3.2.4 of Bjerndalen et al., “Methods for Evaluation of the Nordic Forward Market for Electricity” for a discussion of appropriate time thresholds for the correlation analysis.
Table 10 shows the correlation of calendar-month averages of the difference between the system price and the bidding zone price for each of the Nordic bidding zones, covering the period 01.01.2015 to 31.11.2020. This difference or spread is the underlying reference of EPAD contracts.

Among those Norwegian bidding zones with exchange-traded EPADs (NO1, NO3 and NO4), there is little correlation among the associated spreads. This implies the presence of different local price dynamics in these zones and potentially justifies the existence of different hedging products for them. For those Norwegian bidding zones currently without exchange-traded EPADs (NO2 and NO5), the system-price spread has been reasonably well correlated with the spread between the system and NO1 price. If the NO1 EPAD is a reasonably proxy for those wishing to hedge area price risk in NO2 and NO5, it might be appropriate to pool liquidity into a single (NO1) EPAD rather than have distinct products for each bidding zone. However, even these relatively high levels of monthly correlation may hide potentially important differences. For example, retailers trying to hedge a fixed-price contract may still be exposed to significant risk if the timing of consumption under their contract tends to occur during those hours in which price variations are most prevalent. In this case, a strong monthly correlation may be insufficient to form a useful hedge.

The chart shows that there is a negative correlation between Norwegian spreads and those in the Swedish and Danish bidding zones.

**Table 10: Correlation, monthly-average spot-price spreads, last five years, EPADs**

<table>
<thead>
<tr>
<th></th>
<th>NO1-SYS</th>
<th>NO2-SYS</th>
<th>NO3-SYS</th>
<th>NO4-SYS</th>
<th>NO5-SYS</th>
<th>SE1-SYS</th>
<th>SE2-SYS</th>
<th>SE3-SYS</th>
<th>SE4-SYS</th>
<th>DK1-SYS</th>
<th>DK2-SYS</th>
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<tbody>
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<td>NO1-SYS</td>
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<td></td>
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<td>0.66</td>
<td>0.90</td>
<td>0.96</td>
<td>0.97</td>
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</table>

*Source: THEMA calculations, Montel data*

To give further insight into the trend of the correlations between the relevant price areas, we expand this analysis by looking at the development of the correlation over the last decade. First, we show in Figure 33 the correlation in weekly average spot prices between the Nordic system price and the relevant bidding zones for the period 2010 to 2020. The figure shows the correlation in the weekly average spot prices over a rolling time window of one full year, backward, meaning the data point for the last week of 2010 shows the correlation of the full year of 2010. Following this approach, Figure 34–Figure 38 show the equivalent results from the perspective of the NO2, NO1, NO3, NO4 and NO5 bidding zones, respectively.
Figure 33: Correlation, weekly average spot, between Nordic System price and relevant bidding zones

Data source: Montel.
Note: The correlation covers a rolling time window of one year (52/53 weeks), backward.

Figure 34: Correlation, weekly average spot, between NO2 spot price and relevant bidding zones

Data source: Montel.
Note: The correlation covers a rolling time window of one year (52/53 weeks), backward.
Figure 35: Correlation, weekly average spot, between NO1 spot price and relevant bidding zones

![Graph showing correlation between NO1 spot price and relevant bidding zones]

Data source: Montel.
Note: The correlation covers a rolling time window of one year (52/53 weeks), backward.

Figure 36: Correlation, weekly average spot, between NO3 spot price and relevant bidding zones

![Graph showing correlation between NO3 spot price and relevant bidding zones]

Data source: Montel.
Note: The correlation covers a rolling time window of one year (52/53 weeks), backward.
Figure 37: Correlation, weekly average spot, between NO4 spot price and relevant bidding zones

Data source: Montel.
Note: The correlation covers a rolling time window of one year (52/53 weeks), backward.

Figure 38: Correlation, weekly average spot, between NO5 spot price and relevant bidding zones

Data source: Montel.
Note: The correlation covers a rolling time window of one year (52/53 weeks), backward.

Outside the Nordics

Traded volumes and churn rates

Information on traded volumes and churn rates has been sourced from the British regulator, Ofgem, and from ACER.

The Ofgem data includes monthly volumes data for the period 2010 to 2020.\textsuperscript{31}

\textsuperscript{31} See: https://www.ofgem.gov.uk/data-portal/wholesale-market-indicators
Figure 39 shows these monthly traded volumes (TWh) for Great Britain, split between Over-the-counter (OTC) trading and exchange-based trading. The figure shows that trade volumes are dominated by OTC trade. There is no observable trend in total traded volumes.

**Figure 39: Traded volumes (TWh), monthly values**

![Graph showing monthly traded volumes (TWh) for Great Britain, split between OTC and exchange-based trading.](image)

**Source:** Ofgem

Figure 40 shows these traded volumes in relation to physical consumption, namely the churn rate. Throughout the studied period, the churn rate has been around 3-4.

**Figure 40: Traded volumes in relation to physical consumption (Churn rate), monthly values**

![Graph showing churn rate per month for Great Britain.](image)

**Source:** Ofgem

The ACER data is drawn from the forward market liquidity assessment included in the ACER Market Monitoring Report (2019). Figure 41 below shows annual traded volumes in relation to physical consumption, the churn rate, for the years 2015-2019. For the Nordics and Great Britain, these results correspond to those shown previously in Figure 14 and Figure 40 above.

Figure 41 shows that the German churn rate is many times higher than that of Great Britain, the Netherlands and the Nordics, highlighting the comparatively good liquidity of the German market.
Figure 41: Churn rate (2015-2019)

![Bar chart showing churn rates for Germany, Great Britain, Netherlands, and Nordic regions from 2015 to 2019.](chart)


A further decomposition of the 2019 churn rate is presented in Figure 42, split between exchange-based and OTC trading. The majority of trading is done OTC in all of the relevant countries. The Nordics has a relative high share of total volumes traded via the exchange among this set of countries.

Figure 42: Forward markets churn rate per type of trade (2019)

![Bar chart showing churn rates for different types of trades (Power Exchange Forward and OTC) for Germany, Great Britain, Netherlands, and Nordic regions.](chart)


**Bid-ask spreads**

Comparative data on bid-ask spreads is again drawn from the ACER Market Monitoring Report (2019).

Figure 43 shows average bid-ask spreads (EUR/MWh) of OTC yearly products with a delivery period of 2019-2021 for Germany, Great Britain, the Netherlands and the Nordics. The figure shows that, on average, Germany power contracts have the lowest bid-ask spreads (around 0.1-0.2 EUR/MWh), while Dutch power contracts have the highest (around 0.3-0.4 EUR/MWh). Nordic contracts show spreads of 0.20-0.26 EUR/MWh.

It is worth noting that the reported Nordic bid-ask spread presumably relates to the hedging of the system price and that the bid-ask spread associated with hedging a specific area price is considerably larger. For example, average bid-ask spreads for Oslo EPADs with delivery in 6 to 18 months are around 0.64 EUR/MWh on the exchange, several times the bid-ask spread for Nordic system price contracts. It should be borne in mind therefore that, though the implied bid-ask spread costs of hedging the Nordic system price OTC may not be large in the European context, the quality of the resultant hedge is unlikely to be as good as that provided by the other futures listed below.
Making up the difference in quality, by using an EPAD, is likely to add significantly to the costs of hedging.

**Figure 43: Average bid-ask spreads of OTC yearly products - 2019-2021 delivery (EUR/MWh)**

![Graph showing average bid-ask spreads of OTC yearly products](image)

Source: ICIS, via ACER Market Monitoring Report 2019

Note: Daily bid-ask spreads were averaged out throughout the period from 18 to 6 months before delivery start. For Great Britain, the half-yearly (winter and summer) products were used, and daily bid-ask spreads averaged out throughout the period from 12 to 6 months before the delivery start of each product.
APPENDIX 2 – EXCLUDED METRICS

As mentioned in Appendix 1, the NordREG metrics for Germany and the Netherlands were calculated using data available from Montel. However, we have concerns about the quality of the data and have therefore excluded these results from the main report. They are presented here for completeness.

**Germany**

Germany and Austria used to have a combined power bidding zone, which was split on October 1st, 2018. Prior to this, EEX launched Austrian-only futures starting on the 26th of June 2017. This split is reflected in numbers for the German power futures, as shown in Figure 44 below. Trading data is first recorded in mid-2017, after which open interest slowly increases. The increase in open interest from 2018 onwards is probably mostly affected by the transition of liquidity from the previous German/Austrian power futures, to the German-only and Austrian-only power futures.

**Figure 44: Open interest (TWh) German power futures**

![Figure 44: Open interest (TWh) German power futures](image)

Source: EEX, via Montel

**Figure 45: Open interest in relation to physical consumption**

![Figure 45: Open interest in relation to physical consumption](image)

Source: EEX, via Montel; ENTSO-E Transparency Platform
Figure 46: Daily traded volumes (TWh)

Source: EEX; GFI, via Montel
Notes: The traded volumes are averaged over a rolling time window of 30 days, backward.

Figure 47: Daily traded volumes (TWh)

Source: EEX; GFI, via Montel
Notes: The traded volumes are averaged over a rolling time window of 30 days, backward.
Figure 48: Traded volumes in relation to physical consumption (Churn rate). 30 days rolling average, backward

Source: EEX; GFI, via Montel; ENTSO-E Transparency Platform
Notes: The traded volumes are averaged over a rolling time window of 30 days, backward.

The Netherlands

Figure 49: Open interest (TWh) Dutch Power Futures

Source: EEX, via Montel
**Figure 50: Open interest in relation to physical consumption**

Source: EEX, via Montel; ENTSO-E Transparency Platform

**Figure 51: Daily traded volumes (TWh), NL**

Source: EEX; GFI, via Montel

Notes: The traded volumes are averaged over a rolling time window of 30 days, backward.
Figure 52: Daily traded volumes (TWh) by contract types

Source: EEX; GFI, via Montel
Notes: The traded volumes are averaged over a rolling time window of 30 days, backward.

Figure 53: Traded volumes in relation to physical consumption (Churn rate)

Source: EEX; GFI, via Montel
Notes: The traded volumes are averaged over a rolling time window of 30 days, backward.