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Integration of Electricity Markets

An Analysis of TSO-Owned and Non-TSO-Owned

Cross-Border Interconnectors

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Abstract

The European electricity market is gradually becoming more integrated due to increased cross-border transmission capacity. Integrated electricity markets are expected to improve social welfare through security of supply and efficient electricity generation. Thus, inadequate cross-border transmission capacity causes an inefficient allocation of resources at a regional level.

The integration of electricity markets will impact electricity prices and the social welfare in the connected regions. A cross-border interconnector between the bidding zone NO5 in Norway and the market area Great Britain will exploit the different price levels and structures of the regions. The interconnector is expected to increase electricity prices in NO5 and decrease electricity prices in Great Britain. Further, the social welfare is expected to increase in both NO5 and Great Britain.

This thesis estimates the annual congestion rent of a 1 400 MW interconnector between NO5 and Great Britain. The Norwegian share of the congestion rent is estimated to vary between €51,4 million and €168,4 million in the period from 2026 to 2045. To account for the uncertainty in the future price differential between the two power markets, the range of the estimated congestion rent is constructed from the positively skewed distribution of the historical price differential from 2011 to 2017. This thesis finds that the range of the estimated congestion rent is expected to differ greatly from the baseline. Moreover, alteration in the electricity mix of power markets and additional cross-border interconnectors are identified as sources of uncertainty for the future price differential, which in turn will impact the congestion rent.

This thesis argues that a non-TSO investor will under-provide cross-border transmission capacity relative to what is socially desirable on a national level. Moreover, the capacity decision of a non-TSO investor is affected by the income regulation of the interconnector. If national regulatory authorities wish to encourage non-TSO investments in transmission capacity, the income regulation of interconnectors must be in the favour of the interconnector owners. Further, the income regulation must account for the uncertainties in the future price differential. This thesis identifies a sufficiently high revenue cap, an extended settlement period, an incorporation of a revenue floor and a higher allowed share of revenues derived from capacity markets as possible solutions to incentivise non-TSO investments in interconnectors through income regulation.

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List of Abbreviations

ACER	The Agency for the Cooperation of Energy Regulators
CEF	Connecting Europe Facility
DWL	Dead weight loss
EEA	European Economic Area
ENTSO-E	European Network of Transmission System Operators for Electricity
EU	European Union
EUR	Euro
GB	Great Britain
GBP	Pound sterling
HVDC	High Voltage Direct Current
kWh	Kilowatt hour
MTI	Merchant Transmission Initiative
MW	Megawatt
MWh	Megawatt hour
NSL	North Sea Link
NVE	The Norwegian Water Resources and Energy Directorate
OED	The Norwegian Ministry of Petroleum and Energy
PCI	Projects of Common Interest
PV	Present value
RES	Renewable energy sources
SEM	Single Electricity Market
TEN-E	The Trans-European Networks for Energy
TSO	Transmission system operator
TYNDP	The ENTSO-E 10-Year Network Development Plan
TWh	Terawatt hour

1. Introduction

Cross-border interconnectors facilitate a closer integration of electricity markets. Benefits of integrated electricity markets include improved social welfare, security of supply and more efficient electricity generation. The integration of European electricity markets has been on the agenda for policy-makers since the 1960s and is considered an important tool to optimise energy supply. Following the deregulation of electricity markets in Northern Europe in the 1990s and the implementation of the Energy Union by the European Union (EU) in 2015, there has been a cohesive effort to encourage the development of cross-border transmission capacity.

Norway is gradually becoming more integrated with the European electricity market. Currently, two cross-border interconnectors are being constructed from Norway to Germany and to the UK, whereas a second interconnector to the UK, NorthConnect, is being evaluated. NorthConnect differs from the other interconnectors as it will not be owned and operated by the Norwegian state-owned transmission system operator (TSO) Statnett. If granted a concession, NorthConnect will be the first non-TSO-owned cross-border interconnector in Norway.

In 2016, the Norwegian Government amended the Energy Act § 4-2, allowing other agents than Statnett and enterprises in which Statnett has a controlling interest to own and operate cross-border interconnectors. The decision was heavily debated. The Federation of Norwegian Industries is one stakeholder opposed to the decision to allow other agents than Statnett access to cross-border interconnectors and argues that NorthConnect will lead to higher electricity prices and thus additional costs for the Norwegian energy-intensive industries (Lie, 2018). However, as argued by Nordhagen (2018) from NorthConnect, "the socio-economic gain is at least NOK 10 billion. NorthConnect is owned by public power companies, and this gain will benefit the entire Norwegian society". Further, Nordhagen (2018) states that "a cable between Norway and the UK will contribute positively to the climate, as hydroelectric power will replace coal and gas".

Following the amendment of the Norwegian Energy Act § 4-2, an income regulation of a non-TSO-owned cross-border interconnector must be formulated. The current discussion concerns how the income regulation should differ from the income regulation of a TSO-owned interconnector. NorthConnect has applied for a revenue cap regulation for the Norwegian share of the cable, and has suggested a cap based on a rate of return higher than 8 %. Many stakeholders have argued that this cap is too high including the Federation of Norwegian industries: "We believe this is too high, and that the rate of return (of Norwegian network companies) set by NVE, announced to be 5,88 % in 2018 (...) should be the maximum" (Lie, 2018). Contributing to the discussion of income regulation of non-TSO-owned interconnectors, this thesis will answer the following research questions.

How will the uncertainty in electricity prices affect the congestion rent of a cross-border interconnector, and how can the income regulation of interconnectors account for the uncertainties and encourage the development of cross-border transmission capacity?

In this thesis, we will estimate the congestion rent of an interconnector between the bidding zone NO5 in Norway and the market area Great Britain in the UK using simulated future electricity prices provided by the TheMA model. By assessing the distribution of historical electricity prices provided by Nord Pool, we wish to construct a range of outcomes of the estimated congestion rent. We hope that the potential range of the estimated congestion rent will account for some of the uncertainty in the future electricity prices. Finally, we will investigate how income regulation of interconnectors may affect the estimated congestion rent.

The motivation behind the topic of integrated electricity markets is threefold. First, we wish to assess a topic that is of importance to the society. Electricity is a vital commodity for consumers, and the authorities therefore wish to secure its population with reliable and affordable electricity. These goals can be achieved by facilitating more trade of electricity through cross-border interconnectors, making countries less dependent on their own resources. Thus, integrated electricity markets have a benefit to the society.

Second, being business students specialising in economics and energy economics, the interaction between private and public agents in an economy, specifically an electricity market, is of interest. Third, the integration of electricity markets through additional cross-border transmission capacity is a widely discussed topic in the public debate following the Norwegian government's decision to allow other agents than Statnett to own and operate cross-border interconnectors.

This thesis consists of eight chapters, which provides the reader with a comprehensive assessment of the integration of electricity markets, specifically TSO-owned and non-TSO-owned interconnectors. The first chapter introduces the topic of integration of electricity markets and states the research questions. The second chapter includes an overview of electricity markets and cross-border interconnectors. The third chapter gives a review of the literature on integrated power markets and positions this thesis in the literature landscape.

The theoretical frameworks relevant for our thesis are outlined in the fourth chapter. The fifth chapter introduces the methodology applied for the analysis of the thesis. The sixth chapter, the analysis, evaluates the historical development of electricity prices, future simulated electricity prices and the congestion rent of an interconnector. The discussion in the seventh chapter critically examines the findings of this thesis in light of the background, literature and theoretical frameworks. We conclude in the eighth and final chapter.

2. Background

This chapter provides the background for the master thesis. First, the chapter gives an overview of the Norwegian and the UK electricity markets and electricity price volatility. Second, energy regulation in Norway and the EU is presented. Third, the chapter describes the common power exchange Nord Pool. Thereafter, an in-depth study of cross-border interconnectors and an overview of the planned interconnector NorthConnect is provided. Finally, the chapter presents income regulatory regimes of interconnectors.

2.1. Electricity markets

2.1.1 *The Norwegian electricity market*

The most distinctive feature of the Norwegian electricity market is the almost complete dominance of electricity generation from hydroelectric power plants. In 2017, Norway generated 95,8 % of its annual power production of 149 TWh from hydro power (Statistics Norway, 2018b). Whereas the electricity mix in many countries consists of larger elements of thermal power, only 2,3 % of the Norwegian power production originated from thermal power. The remaining 1,9 % of production was generated from wind power plants. Consequently, the Norwegian electricity mix has the highest share of intermittent renewable energy sources (RES) in Europe. See Appendix 9.1 for the historical development of the Norwegian electricity generation by source.

Norway's large hydro power reservoir capacity and integration to neighbouring countries contributes to balance the variation of supply and demand in the connected regions (IEA, 2017). In 2017, Norway had an interconnector capacity to other countries of 6 200 MW (see Appendix 9.3). This corresponded to around 18,1 % of the total installed electricity production of 34 200 MW in Norway (Statistics Norway, 2018a). The level of Norwegian export and import of electricity varies from year to year and depends strongly on weather factors including the level of inflow to the hydro reservoirs (OED, 2016). Historically, Norway has been a net exporter of electricity, and Norway had a net export of 15 TWh in 2017 (Statistics Norway, 2018b).

2.1.2 *The UK electricity market*

The UK power market is characterised as a thermal power market with a significant proportion of RES generation. In 2017, the UK generated 336 TWh of electricity (BEIS, 2018). The annual power production in the UK originates mainly from gas (39,7 %), RES (29,4 %) and nuclear (20,9 %). The largest share of the RES generation capacity is wind power, which have increased over the last years. In 2017, onshore wind power accounted for two-thirds of the total wind power production in the UK, whereas offshore wind accounted for the rest. The share of coal generation in the power mix is steadily declining and the UK generated only 6,7 % of its electricity from coal in 2017. The historical development of the UK electricity generation by source is presented Appendix 9.2.

The UK is integrated with the European continental electricity market through interconnectors to France and the Netherlands, as well as with Ireland (see Figure 2.3). The current UK interconnector capacity of 4 100 MW represents 5,0 % of the total installed generation capacity of 81 300 MW (BEIS, 2018). Electricity prices are typically higher in the UK than in neighbouring countries in Northwestern Europe (Houses of Parliament, 2018). The UK is a net importer of electricity, and had in 2017 a net import via interconnectors of 15 TWh (BEIS, 2018).

2.2. Volatility of electricity prices

Electricity is characterised as a flow commodity, meaning that there are limited possibilities to store and transport the commodity (Lucia and Schwartz, 2002). A power market must be in continuous balance and therefore electricity must be generated and used simultaneously (Sleire et al., 2015). Thus, electricity prices are dependent on the availability of generation capacity and the elasticity of demand (Benini et al., 2002).

Limited possibilities to store electricity, in addition to fuel and carbon prices, weather conditions as precipitation and temperature, congestion on the regional grid and the regulation and management of the specific electricity market, contributes to the volatility of electricity prices (Benini et al., 2002, Sleire et al., 2015). Further, a higher share of generation capacity from intermittent RES in the electricity mix may increase the volatility of electricity prices (Pöyry, 2014, NorthConnect, 2017). Finally, additional cross-border interconnetors may impact the volatility of electricity prices (NVE, 2017).

The electricity prices in the Nordic power markets are characterised as volatile, with abrupt and high price spikes in situations of interruption in generation or transmission capacity (Sleire et al., 2015), but compared to other European countries the price structure in Norway is relatively flat (NorthConnect, 2017). The large share of flexible hydroelectric power in Norway and Sweden, i.e. hydro power with storage in reservoirs, contributes to relatively low short term price fluctuations in the Nordic power markets (Hoel et al., 2014). Nevertheless, the inflows to reservoirs explain most of the long-term price volatility in the Nordics (Liski and Vehviläinen, 2016). Electricity prices are also dependent on season and climate (Lucia and Schwartz, 2002, Liski and Vehviläinen, 2016), in which the Nordic electricity prices are more volatile during warmer months than colder months (Lucia and Schwartz, 2002, Johnsen et al., 1999).

The UK electricity prices exhibit a high degree of intraday volatility, which is common for thermal power markets (Robinson and Baniak, 2002, Karakatsani and Bunn, 2004).

2.3. Energy policies

2.3.1 *Energy policies of Norway*

The Norwegian electricity market was deregulated by the Energy Act of 1990. The objective of the Norwegian Energy Act (1990, § 1-2) is to ensure that production, transformation, transmission, sales, distribution and use of electricity is organised in a socio-economic efficient manner. Following the deregulation, and several amendments to the Energy Act, the Norwegian electricity market has become an open market-based system for production and trade of electricity, while grid operations remain strictly regulated.

The Norwegian Parliament defines the political framework for energy resource management in Norway, in which the Ministry of Petroleum and Energy (OED) has the overall responsibility to implement the policies (OED, 2015). In the White Paper "Power for change - an energy policy towards 2030", OED (2016) describes long-term focus areas for the electricity sector. The policies aim at enhancing security of supply, facilitating efficient production of RES, ensuring efficient and climate-friendly use of energy, and increasing the value creation of Norway's renewable energy resources (OED, 2016).

In order to increase the value of the Norwegian hydroelectric power generation, the Norwegian Government has implemented regulations that facilitate closer integration with the European electricity market and underpinning key elements of EU policies. One example is that the Norwegian Energy Act (§ 4-2) was changed in 2016 to allow other agents than the state-owned TSO, Statnett, to own and operate cross-border interconnectors. However, in 2018 the Committee on Energy and the Environment of the Norwegian Parliament asked the Norwegian Government to propose an amendment to the Energy Act to restrict the ownership of cross-border interconnectors to Statnett or enterprises in which Statnett has a controlling interest (Norwegian Parliament, 2018).

Further to the national legislation, there are a number of EU directives and regulations that influence the Norwegian electricity market through the European Economic Area (EEA) Agreement.

2.3.2 *Energy policies of the European Union*

Energy markets across Europe have gradually become more integrated and harmonised as EU's three internal energy market packages have been implemented. The First Energy Package of 1996 provides a framework of common rules with the aim to create an integrated, internal electricity market (European Parliament, 2018). A further step towards a fully integrated market was the approval of the Second Energy Package in 2003, which includes regulations on cross-border interconnectors to increase trade of electricity (European Parliament, 2018). The Third Energy Package from 2009 comprises legislative acts concerning common rules for electricity, natural gas and access to transmission networks within the EU (European Commission, 2015). The Third Energy Package also establishes a framework ensuring cooperation among national regulators and TSOs called the Agency for the Cooperation of Energy Regulators (ACER) (European Commission, 2015).

In 2015, the European Commission established the Energy Union to serve as a framework for the existing European energy policies. The Energy Union aims at encouraging security of energy supply and achieving a fully integrated European energy market, among others (European Commission, 2015). According to the European Commission (2015), the planned investment in cross-border transmission capacity is insufficient to achieve a fully integrated internal market. To facilitate construction of the missing infrastructure links, a minimum target for interconnector capacity has been set. By 2030, all Member States should achieve interconnector capacity of 15 % of the installed electricity generation capacity (European Commission, 2015). As of 2017, twelve Member States have not yet reached this target (European Commission, 2017). Further, the European Commission proposed in 2016 to transfer part of the the congestion rent to an EU fund supporting construction of new cross-border interconnectors (THEMA, 2017).

The European Commission (2015) has launched several initiatives to encourage investment in interconnectors, most notably the Projects of Common Interest (PCIs). If a project is accepted as a PCI, it is eligible to apply for funding from the Connecting Europe Facility (CEF) programme (THEMA, 2017). The European Network for Transmission System Operators for Electricity (ENTSO-E) coordinates the development of more cross-border capacity (European Parliament, 2018). The Trans-European Energy Networks for Electricity (TEN-E) is an example of EU law that targets closer integration of electricity markets across national borders (European Commission, 2011). Finally, the Merchant Transmission Initiative (MTI) aims at strengthening European integration by exempting certain cross-border interconnector investments from regulation (Poudineh and Rubino, 2016).

2.4. The Nord Pool power exchange

The deregulation of the Norwegian electricity market laid the foundation for the establishment of a power exchange in 1993 (Lucia and Schwartz, 2002). This power exchange was later renamed Nord Pool. In the following years, the other Nordic electricity markets conducted similar deregulation processes as Norway and joined Nord Pool, except for Iceland. Later, Estonia, Lithuania and Latvia joined Nord Pool. In 2010, Nord Pool launched the N2EX power market in the UK.

Nord Pool is divided into bidding zones set by the local TSOs to handle congestion in the national electricity grid. The Norwegian electricity market is currently divided into five bidding zones (NO1-NO5), as illustrated in Figure 2.1. The electricity market in the UK is divided into two market areas. Great Britain (GB) includes England, Scotland and Wales, whereas Northern Ireland takes part in the Single Electricity Market (SEM) together with Ireland (Houses of Parliament, 2018).

Nord Pool serves as the physical power exchange and operates the day-ahead and intraday markets in the Nordics, the Baltic states and the UK (Nord Pool, 2017). Most of the traded volume is settled in the day-ahead market, Elspot, where the market is cleared at noon and electricity is delivered the following day (OED, 2015). Based on orders submitted to the Elspot market

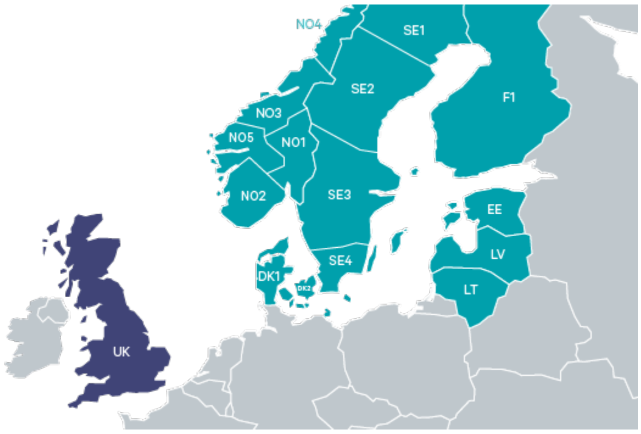

Figure 2.1 – Bidding zones of the Nord Pool power exchange. Image retrieved from Nord Pool (2018a).

by Nord Pool's customers, a price for each delivery hour in every bidding zone is established. Subsequently, Nord Pool calculates the system price based on sale and purchase orders disregarding transmission capacity constraints between the bidding zones (Nord Pool, 2018b). The system price is used as a reference price for trading and clearing of financial contracts (OED, 2015). The intraday market, Elbas, works as a supplement to balance day-ahead contracts due to changes in demand or supply, and offers trading up until one hour before delivery (OED, 2015).

2.5. Cross-border interconnectors

Turvey (2006) defines an interconnector as a transmission cable that connects two separate power markets. Cross-border interconnectors facilitates the trade of electricity between different national power markets and causes power markets to become more integrated (Statnett, 2017a).

2.5.1 *Benefits of cross-border interconnectors*

There are several benefits of integrated power markets. Due to the difficulty of quantifying the benefits of an interconnector as argued by Turvey (2006), this master thesis is restricted to only qualitatively outline the main benefits of cross-border interconnectors.

The main motivation behind building cross-border interconnectors is to take advantage of the different characteristics of power markets (Murray, 2009). Power markets of different characteristics will have different price levels and price structures, and the price differential between the markets can be exploited through building cross-border transmission capacity (Rud, 2009). The integration of power markets of different characteristics will lead to a better overall resource utilisation (Statnett, 2018b) and increase the efficiency of power generation (Zakeri et al., 2015). A similar benefit of integrated power markets is the possibility to optimise the interaction between supply and demand over a larger geographical area (Auverlot et al., 2014), which in turn will decrease generation costs (Turvey, 2006).

Integrated power markets exhibit a high degree of security of supply (Turvey, 2006, Murray, 2009), which represents an important rationale for decision makers in Europe for supporting construction of more cross-border transmission capacity (Statnett, 2017b).

Specifically for Norway, cross-border interconnectors will increase the value of the Norwegian hydroelectric power system since exports will generally increase the electricity price in Norway (Statnett, 2017b). Due to the high hydroelectric power production and stored capacity in hydro reservoirs, Norway normally has sufficient reserve capacity for continuous balance of production and consumption of electricity (Jaehnert and Doorman, 2010). Thus, more trade will benefit Norway in terms of lower costs for reserve capacity and lower electricity prices in periods of scarce water resources (Statnett, 2018b).

2.5.2 *Income of cross-border interconnectors*

The income of a cross-border interconnector is derived from the congestion rent, revenues from capacity markets and revenues from providing balancing services between markets (Turvey, 2006, Pöyry, 2014).

Congestion rent occurs when electricity is traded from a low-price area to a high-price area (Statnett, 2018a), and is derived from hourly price differentials in the spot market and the interconnector capacity (Pöyry, 2014). The congestion rent typically constitutes the largest share of the interconnector income (NorthConnect, 2017). Congestion arises when the transmission capacity is fully utilised between two markets, and thus the electricity prices of the respective markets continue to differ (Zakeri et al., 2015).

The income of a cross-border interconnector can also be derived from capacity markets by selling capacity contracts to generators and traders (Turvey, 2006). Capacity markets ensure a sufficient amount of reliable capacity in a power market. The dynamics of capacity markets and spot markets, from which the congestion rent is derived, are complementary (NorthConnect, 2017). High spot prices are accompanied by low prices in the capacity market, and opposite.

Capacity markets have not been implemented yet in Norway (OED, 2016). However, the UK allows for trade in capacity markets, but restricts the length of capacity contracts and the volume of the interconnector capacity reserved for capacity contracts (NorthConnect, 2017).

Lastly, an interconnector can derive revenues from balancing markets (Pöyry, 2014). A balancing market is an institutional arrangement, in which the balance between supply and demand is adjusted by a regulator (van der Veen and Hakvoort, 2016). In a sequence of electricity markets, the balancing market is the last after the day-ahead and intraday electricity markets (van der Veen and Hakvoort, 2016).

2.5.3 *Investment objectives and drivers of interconnector owners*

The outlined benefits and the interconnector income are drivers for investment in cross-border transmission capacity. However, the relevance of a specific driver depends on the interconnector ownership. Interconnectors can be subject to different ownerships. In general, interconnector owners are either welfare-maximising TSOs or profit-maximising non-TSOs (THEMA, 2017).

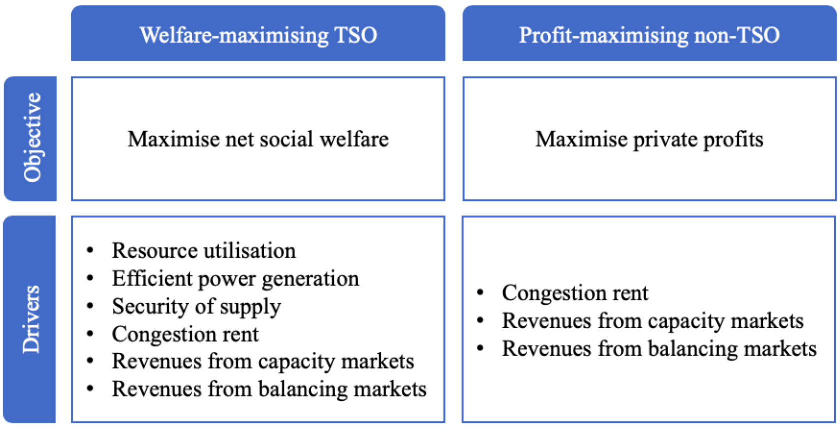

Figure 2.2 – The objective and drivers for the investment decision in a cross-border interconnector of a welfare-maximising TSO and a profit-maximising non-TSO.

The main objective of a TSO is to maximise the net social welfare (THEMA, 2017), making the income of the interconnector only a part of the investment decision. Thus, benefits such as better overall resource utilisation, security of supply and for Norway, increased value of the hydroelectric power system, will be relevant investment drivers for a welfare-maximising TSO.

A non-TSO investor aims at maximising private profits (THEMA, 2017). Thus, the decision to invest in an interconnector is mainly based on the interconnector income of a cable and not the outlined benefits (Turvey, 2006).

2.5.4 *Risks related to the income of cross-border interconnectors*

Statnett (2017b) argues that there is a significant uncertainty in the future development of power markets and electricity prices in Norway and Northern Europe. Since the congestion rent depends on the price differential between markets, the income of an interconnector is exposed to the risk of low price differentials. Moreover, new generation capacity and decommissioning of existing generation capacity may alter the electricity mix which in turn will have implications for the price differential and thus the congestion rent (Poudineh and Rubino, 2016). The congestion rent is also exposed to the risk of a cannibalism effect (Pöyry, 2014, Spiecker et al., 2013). A cannibalism effect occurs when a new interconnector causes prices to converge across power markets, which in turn reduces the congestion rent of existing interconnectors.

The capacity of the national transmission grid in the connected regions represents an additional uncertainty regarding the size and durability of future congestion rents. For Norway, Statnett (2017b) argues that planned cross-border interconnectors may enhance the load on the national grid, which in turn will require costs related to grid reinforcements.

The level of regulation of cross-border interconnectors constitutes an uncertainty for the interconnector owner. Changes in the income regulation and the congestion management are sources of risks for the profitability of the interconnector (Poudineh and Rubino, 2016). For instance, the tariff regulation for the Norwegian gas transportation system was altered in the so-called Gassled case, reducing the potential upside revenues for the investors (Seglem, 2018).

Lastly, an owner of a cross-border interconnector is exposed to project specific risks that will affect cost recovery, including delays in construction. Difficult interaction between stakeholders across borders and local opposition have been main reasons for delays in the authorisation and the permitting process of interconnectors (Auverlot et al., 2014, Dutton and Lockwood, 2017).

2.5.5 *Existing and planned cross-border interconnectors*

The Norwegian power market is integrated with the power markets of other Nordic countries and Continental Europe through cross-border interconnectors (IEA, 2017). The existing and planned cross-border interconnectors in Northern Europe are shown in Figure 2.3.

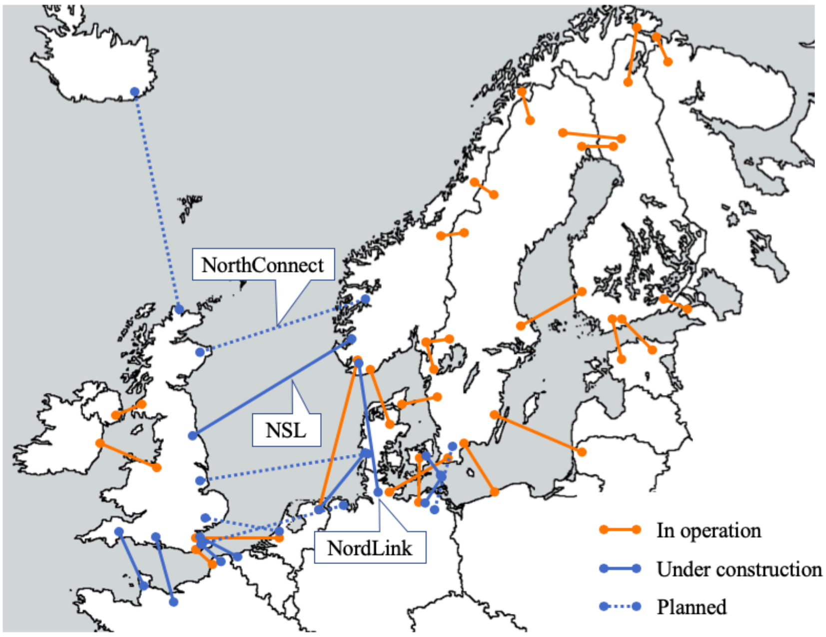

Figure 2.3 – Existing (orange) and future (blue) cross-border interconnectors in Northern Europe. Interconnectors under construction are marked by a solid blue line, whereas planned interconnectors are marked with a dotted blue line. An extensive overview of the cross-border interconnectors can be found in Appendix 9.3 and 9.4. Authors' own illustration.

There are currently two cross-border interconnectors under construction from Norway. The subsea HVDC cable NordLink from bidding zone NO2 in Norway to Northern Germany will have a transmission capacity of 1 400 MW (NVE, 2017). NordLink is expected to be in operation around year 2020 and is jointly (50/50) developed between the Norwegian state-owned TSO Statnett and DC Nordseekabel (owned by the German TSO TenneT and the investment bank KfW). The subsea HVDC cable North Sea Link (NSL) from bidding zone NO2 in Norway to the UK will have a capacity of 1 400 MW and is expected to be in operation by 2021. NSL is developed 50/50 between Statnett and the British TSO National Grid. NordLink and NSL will increase Norway's interconnector capacity to about 9 000 MW.

2.5.6 *The non-TSO-owned interconnector NorthConnect*

A third interconnector, NorthConnect, between bidding zone NO5 in Norway and Scotland in the UK, is planned but not approved. The NorthConnect project envisages construction of a 665 km long HVDC subsea cable with a transmission capacity of 1 400 MW. It is planned that NorthConnect will be in operation by the year 2023. NorthConnect is owned by the consortium of the four public Nordic power companies; Agder Energi AS, E-CO Energi AS, Lyse Produksjon

AS and Vattenfall AB. (NorthConnect, 2017)

NorthConnect applied in June 2017 for a concession to own and operate a cross-border interconnector (NorthConnect, 2017). The concession application is currently being evaluated by the Norwegian Water Resources and Energy Directorate (NVE), who is scheduled to advice OED after Christmas 2018. OED will decide whether to grant NorthConnect a concession or not during the spring of 2019. The final investment decision is scheduled for 2019 (NorthConnect, 2017).

The concession application of NorthConnect (2017) estimates that the cable will increase social welfare in Norway by a minimum of €112 million in all years in the business as usual scenario, as shown in Table 2.1. Based on the analysis of NorthConnect, the Norwegian consumer surplus is estimated to fall, whereas the producer surplus will increase. The congestion rent of the Norwegian share of NorthConnect is estimated to vary between €55 million and €90 million. The capacity market revenues are based on the assumption that NorthConnect is granted participation in the UK capacity market (NorthConnect, 2017). Appendix 9.5 presents the congestion rent of NorthConnect in the business as usual scenario and three additional scenarios together with a short description of the scenarios.

	CS	PS	CR	CM	Social welfare
2023	-266	289	88	21	132
2025	-229	253	90	21	134
2030	-259	299	57	19	116
2035	-251	300	59	18	127
2040	-230	273	55	13	112
2045	-127	171	82	13	140

Table 2.1 – The welfare estimates of the Norwegian share of NorthConnect in 2016 million EUR for the business as usual scenario. The social welfare is given by the change in consumer surplus (CS), producer surplus (PS), congestion rent (CR) and capacity market revenues (CM). (NorthConnect, 2017)

The NorthConnect concession application states that the interconnector will increase the Norwegian electricity prices with 1,7 Norwegian øre/kWh in 2030 in the business as usual scenario. For the other scenarios the price effect will be smaller. Due to the size of the UK power market, the effect of NorthConnect on the British electricity prices will be smaller than the effect on Norwegian prices. (NorthConnect, 2017)

The annualised capital and operational related costs of the NorthConnect interconnector are estimated to €92 million and €10 million p.a., respectively. The interconnector project is one of the highest ranked PCIs in Europe. It is co-financed by the EU and received €10,7 million in development support through the CEF programme in 2016. (NorthConnect, 2017)

2.6. Income regulation of cross-border interconnectors

Interconnectors are considered to be natural monopolies and are therefore subject to economic regulation (Poudineh and Rubino, 2016). Regulating natural monopolies are considered difficult because their costs are not perfectly known to the regulator (Baron and Myerson, 1982).

Cross-border interconnectors in Europe are subject to various regulatory regimes. Generally, a cross-border interconnector is regulated by the respective national regulatory authorities in the power markets it connects. Thus, cross-border interconnectors are exposed to two or more regulatory authorities (Kapff and Pelkmans, 2010). A national regulator usually sets economic regulations for 50 % of the interconnector (Ofgem, 2018), including conditions that govern the amount of revenues the interconnector owner can retain.

National regulatory authorities have developed individual regulatory models tailored for national costs and benefits (Kapff and Pelkmans, 2010). It is recommended for a regulator to set the conditions such that revenues collected by the investor will cover costs and risks of the interconnector (van Koten, 2012). Additionally, the redistributing mechanisms of the income regulation should be assessed separately for each area (Auverlot et al., 2014). In Norway, the interconnector revenues are regulated and controlled by NVE (Statnett, 2018a).

The income regulation of cross-border interconnectors ranges from unregulated to fully regulated, as illustrated by Figure 2.4. An unregulated interconnector is a cable where the owner holds all risk but receives all revenues (NorthConnect, 2017). The interval between unregulated and fully regulated regimes consists of regulations that govern how the risk and revenues of an interconnector are distributed between the interconnector owners and the consumers.

A common approach is to agree ex-ante on the maximum revenues that an interconnector owner is allowed to retain, called the revenue cap regulatory regime (NorthConnect, 2017). The maximum revenue retained by the owner is restricted to the level of the revenue cap, as indicated by Figure 2.4. If the revenues of an interconnector exceed the level of the cap, the exceeding amount will be redistributed as a lump sum to the consumers, usually as reduced

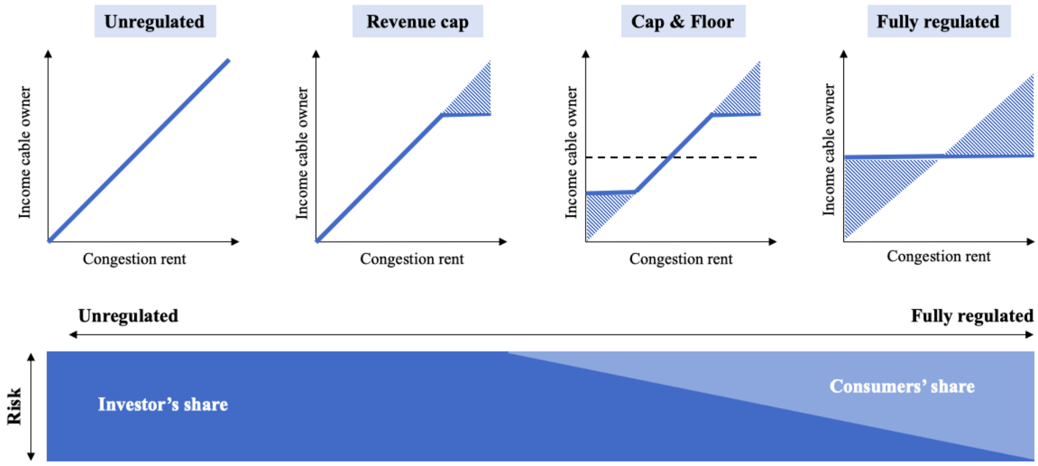

Figure 2.4 – The income retained by the interconnector owner in the unregulated, revenue cap, cap and floor and fully regulated regulatory regimes, and the investor's and consumers' share of risk related to the regulatory regimes. Illustration from NorthConnect (2017) translated by the authors.

network tariffs. The owner holds all of the risk if the interconnector does not generate the necessary revenues to cover costs.

The cap and floor regulatory regime secures a minimum revenue to the interconnector owner equal to the level of the floor, whereas the cap limits the maximum retained revenue (Pöyry, 2014). If revenues are below the floor, the consumers will cover the loss, usually as increased network tariffs. And opposite, if the revenue exceeds the level of the cap, the interconnector owner will pay a lump sum to the transmission network which is redistributed to the consumers as lower network tariffs. Thus, an interconnector owner subject to a cap and floor regulation carries a smaller share of the risk compared to when facing a revenue cap regulation, as illustrated in Figure 2.4.

A cross-border interconnector is fully regulated if the level of the revenue cap equals the predetermined level of the revenue floor (NorthConnect, 2017). An owner of a fully regulated interconnector carries no risk, since all of the risk is distributed to the consumers, as depicted in Figure 2.4. Revenues above the cap will be redistributed to the consumers as reduced network tariff, whereas revenues below the cap will result in higher tariffs.

2.6.1 *Income regulation of TSO-owned interconnectors in Norway*

All Norwegian cross-border interconnectors currently in operation are fully regulated and owned by the national TSO, Statnett. The revenues from the Norwegian share of the interconnectors are redistributed by Statnett to the transmission grid as a lump sum paid annually (NorthConnect, 2017). This lump sum lowers the network tariffs paid by the consumers. However, if the revenues from the TSO-owned interconnectors do not cover the costs of investment and operation, the consumers will cover the costs through higher network tariffs. Thus, Statnett carries no risk as owner of the interconnectors and will earn a predetermined rate of return on its investment. The rate of return on Statnett's cross-border interconnectors is derived using similar principles as to how the income of Norwegian network companies is regulated, as outlined in Appendix 9.6.

2.6.2 *Income regulation of non-TSO-owned interconnectors in Norway*

The legislative amendment of the Norwegian Energy Act (2016, § 4-2) allows other agents than Statnett to own and operate cross-border interconnectors in Norway. If the NorthConnect project is realised, it will be the first non-TSO-owned interconnector in Norway. NorthConnect has applied for a revenue cap regulation for the Norwegian share of the cable, which will be controlled by the regulatory authority NVE (NorthConnect, 2017).

The Norwegian regulatory regime of a non-TSO-owned interconnector is currently being formulated by NVE and has not been set as this thesis is being written. According to the tender document for determining a required rate of return for the Norwegian share of the NorthConnect interconnector, the regulatory regime must ensure that the retained revenues from the interconnector cover costs, depreciation and provides a reasonable rate of return to the owner (NVE, 2018a). The tender document states that the income regulation of a non-TSO-owned interconnector will be based on the cap and floor regulatory regime currently used in the UK, and will have similarities to the income regulation of Norwegian network companies outlined in Appendix 9.6.

A revenue floor for the Norwegian share of a cross-border interconnector is not a legal option (NVE, 2018a), thus a non-TSO-owned interconnector will not receive any risk relief from the Norwegian consumers. Consequently, the owners will carry all the risk of the interconnector. This is contrary to the income regulation of TSO-owned interconnectors in Norway, in which the owner Statnett carries no risk. Thus, the lack of a floor may eliminate the possibility for viable debt funding of the interconnector project (Bjørndal and Johnsen, 2018).

The revenue cap of a Norwegian non-TSO interconnector can be based on the income over settlement periods of different time intervals or accumulated over the lifetime of the project (NVE, 2018a). In each settlement period, the income of the interconnector is settled against the revenue cap. It is proposed that the extraordinary revenue, i.e. the revenues above the revenue cap, will be transferred to Statnett and in turn be used to reduce the tariff paid by the consumers for the transmission network (NVE, 2018a). This is custom in the current regulation of the Norwegian power system. Since losses of the interconnector will not be covered, the proposed revenue cap regulatory regime is asymmetric.

The UK's share of NorthConnect is granted a cap and floor regulation for a period of 25 years (Ofgem, 2018). The cap and floor regulation in the UK is a symmetric regulation used to incentivise agents to invest and build cross-border interconnectors. The level of the cap and floor is set to enable a reasonable rate of return for equity investors, while also cover the cost of debt if the cross-border interconnector was fully funded by debt. The level of the floor set by Ofgem will correspond to the actual cost of debt at the time of contract agreement (Bjørndal and Johnsen, 2018).

Figure 2.5 presents the income of a hypothetical interconnector between Norway and the UK. For the Norwegian share of the interconnector, facing only a revenue cap with a one-year settlement period, the extraordinary revenues will be redistributed to the transmission network each year. In the hypothetical situation depicted in Figure 2.5, only four years during the interconnector's lifetime provides high enough revenues for the revenue cap to be triggered.

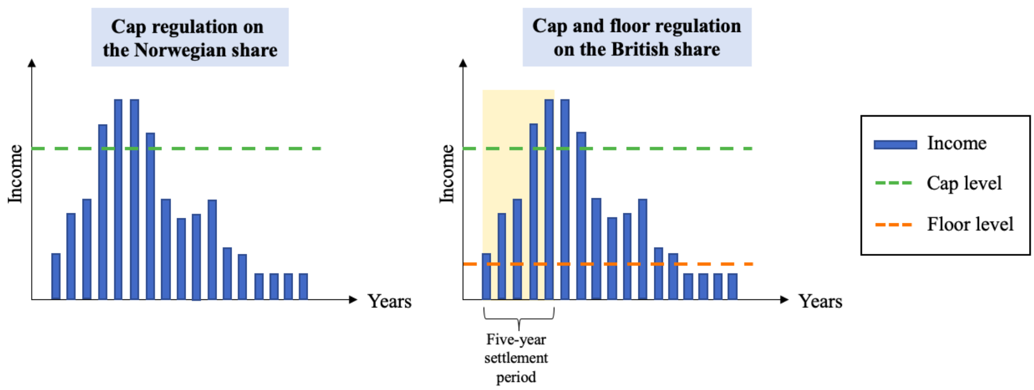

Figure 2.5 – The revenue cap regulation of the Norwegian share and the cap and floor regulation of the British share of a hypothetical interconnector. Authors' own illustration.

For the British share of the hypothetical interconnector, a cap and floor regulation redistributes the extraordinary revenues of the interconnector above the revenue cap to the consumers similar to the revenue cap model. In addition, the floor secures a minimum revenue. If the interconnector income falls below the floor, the British consumers cover parts of the losses by paying higher network tariffs. Moreover, in the cap and floor regulation the settlement of the redistribution to or from the consumers is done every five years. For the situation depicted in Figure 2.5, this implies that the initial three years of lower interconnector income are partly compensated by the subsequent years of higher income, providing a higher retained earnings for the interconnector owners and contributing to less redistribution in each five-year settlement period.

Due to the asymmetry in the Norwegian revenue cap regulation, NorthConnect (2017) argues that the revenue cap in the Norwegian income regulation must be sufficiently high to attract equity investors and provide compensation for the downside risk. Therefore, NorthConnect (2017) argues that the level of the revenue cap for the Norwegian share must be higher than the cap in the UK which is based on a rate of return of 8%.

Similarly, Poudineh and Rubino (2016) state that investments in interconnectors require a high rate of return to attract investors, due to its high risk exposure. Figure 2.6 depicts different revenue cap levels for a non-TSO-owned interconnector, assuming that the probability of risk is evenly distributed around a required rate of return of an interconnector. If the revenue cap level is set equal to the required rate of return, indicated by (i) in Figure 2.6, the interconnector owner will only face the downside risk. Whereas, if the revenue cap is higher than the required rate of return, for instance at the level of (ii), the interconnector owner will retain a larger share of the congestion rent.

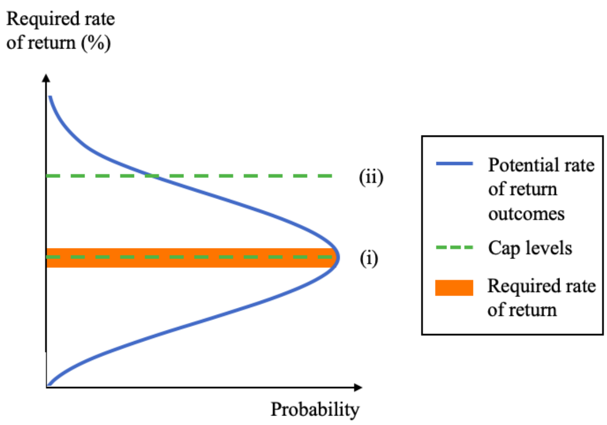

Figure 2.6 – Illustration of different revenue cap levels in the revenue cap regulatory regime for a non-TSO-owned interconnector. Note that the outcome curve is not statistically estimated. Authors' own illustration based on material received from Vattenfall (2018).

3. Literature Review

This chapter gives an overview of the literature on the integration of electricity markets. It serves as a basis for our thesis and aids us in placing the thesis in the literature landscape.

The impact of increased cross-border transmission capacity on electricity prices is a widely studied topic in the literature on the integration of electricity markets. NVE (2017) studies the effect of the planned interconnectors to Germany (NordLink) and the UK (NSL) on the Norwegian electricity prices. NVE (2017) concludes that the two interconnectors will in isolation increase prices by approximately 1 Norwegian øre/kWh by 2025. However, NVE (2017) argues that most of the increase in electricity prices is caused by other factors than additional transmission capacity. According to NVE (2017), increased transmission capacity will lower the difference between summer and winter prices in Norway and short-term price fluctuations will become more common making the Norwegian price structure more similar to that of thermal power markets like Germany and the UK.

Zakeri et al. (2015) analyse the impact of Germany's energy transition (Energiewende) on the Nordic power market, taking the planned interconnector between Norway and Germany, NordLink, into account. The authors find that the additional transmission capacity of NordLink increases the average Nordic system price and most Nordic area prices. The Norwegian electricity price increases from 38,3 €/MWh in 2013 to 40,2 €/MWh after the commissioning of the cable. Consequently, the Nordic power market does not benefit from lower electricity prices in Germany caused by the energy transition. Zakeri et al. (2015) argue that this is due to limited transmission capacity between the markets and that prices are simultaneously low in Germany and Norway.

Similar results have been found by other studies. Spiecker, Vogel and Weber (2013) assess power markets in thirty European countries and find that as interconnectors are developed, electricity prices in the connected areas will converge. Spiecker et al. (2013) also investigate how additional wind power generation will impact electricity prices. The authors find that additional wind power generation will increase the price differentials between connected areas and consequently the congestion rents. Also, Auverlot, Beeker, Hossie, Oriol and Rigard-Cerison (2014) find that the integration of the European power systems has caused electricity prices to converge. Auverlot et al. (2014) argue that the remaining price differentials between regions are caused by limited transmission capacity, inefficient allocation of cross-border interconnectors and institutional discrimination of trade between regions. Persen (2017) concludes in her master thesis that additional transmission capacity causes the Norwegian electricity prices to converge towards Continental electricity prices.

In sum, the literature show that electricity prices converge when power markets become more integrated. Table 3.1 summarises the impact on Norwegian electricity prices. Our thesis will contribute to this part of the literature, since we intend both to investigate how the integration of electricity markets impact prices in theory and to assess future prices in the soon-to-be connected regions in Norway and the UK. Similar to the studies by NVE (2017) and Zakeri et al. (2015), we will investigate the impact of a specific cable and not assess the impact of integration on a European level like Spiecker et al. (2013) and Auverlot et al. (2014).

	Effect on Norwegian electricity prices
NVE (2017)	$\uparrow$
Zakeri et al. (2015)	$\uparrow$
Spiecker et al. (2013)	converge
Auverlot et al. (2014)	converge
Persen (2017)	converge

Table 3.1 – The effect of increased cross-border transmission capacity on Norwegian electricity prices outlined in the studies.

An important aspect of the literature on integrated power markets involves how increased cross-border transmission capacity affect social welfare. The aforementioned study by Zakeri et al. (2015) investigates the effect of additional transmission capacity between Norway and Germany on social welfare. Zakeri et al. (2015) conclude that the commissioning of NordLink will decrease the Norwegian consumer surplus and increase the producer surplus due to higher electricity prices in Norway. In addition, the congestion rent increases, which is caused by both a larger price difference between the connected regions and a higher volume of trade. Thus, Zakeri et al. (2015) find that the social welfare in Norway will improve after the commissioning of NordLink. This is in line with the findings of Persen (2017), who argues that as Norwegian prices converge towards continental prices, the Norwegian producer surplus will grow at the expense of the consumer surplus.

The aforementioned study by Spiecker et al. (2013) also investigates the impact of additional cross-border transmission capacity on social welfare. The authors find that more integrated power markets increase overall welfare, but that the consumers in Norway and the UK experience the highest welfare losses due to higher national prices. Spiecker et al. (2013) observe that as prices converge due to additional transmission capacity, the congestion rent of an interconnector will fall. In addition, the authors find a cannibalism effect as more interconnectors are built. In sum, a lower congestion rent and the cannibalism effect will reduce the incentive to develop additional interconnectors (Spiecker et al., 2013).

The international consulting and engineering firm Pöyry (2014) analyses the economic impact of five interconnectors from the UK, including the NSL cable to Norway. Pöyry (2014) states that the NSL increases the social welfare in both the UK and Norway. The congestion revenue of the NSL decreases initially as the price differential between Norway and the UK declines. However, the congestion rent increases after 2025 due to a higher share of RES generation in the UK and North-western Europe. Pöyry (2014) observes that a higher share of RES generation increases the price volatility and that the UK electricity prices will fall more frequently to low levels. The study concludes that the additional interconnectors from the UK do not impact the social welfare in Norway and the UK, and the congestion rent of the NSL. Thus, Pöyry (2014) excludes a cannibalism effect.

In sum, there exists a well-established literature that shows how the integration of power markets increases social welfare. However, the benefit of integration is not evenly distributed between consumers and producers. Table 3.2 summarises the effect of additional transmission capacity on the Norwegian social welfare. This thesis will study the impact on social welfare of an additional interconnector between Norway and the UK, similar to the studies by Zakeri et al. (2015) and Pöyry (2014). Specifically, it is of interest to assess how the potential benefit of an interconnector is distributed between the consumers, the producers and the interconnector owner. Further, we wish to evaluate the national income regulation designed to redistribute these benefits, a topic not covered by the studies of Zakeri et al. (2015) and Spiecker et al. (2013). This is of particular interest as this thesis focuses on the difference between TSO-owned and non-TSO-owned interconnectors, where regulation plays a key role.

A related part of the literature assesses the difference between a TSO-owned and a non-TSO-owned interconnector. Sereno and Efthimiadis (2018) analyse the optimal transmission capacity developed by a state-owned TSO and a non-TSO transmission investor. The authors find that

	CS	PS	IW	Social welfare
Zakeri et al. (2015)	↓	↑	↑	↑
Persen (2017)	↓	↑		
Spiecker et al. (2013)	↓		↓	↑
Pöyry (2014)			↓/↑	↑

Table 3.2 – The impact of additional cross-border transmission capacity on social welfare as outlined in the studies. The table provides the effect on consumer surplus (CS), producer surplus (PS), interconnector wealth (IW) and overall social welfare in Norway.

the transmission capacity provided by the non-TSO investor is less than the optimal capacity provided by the TSO. Sereno and Efthimiadis (2018) argue that the state-owned TSO will choose the transmission capacity that maximise social welfare, whereas the non-TSO investor will have an incentive to restrict the transmission capacity and thus enhance its congestion rent from the interconnector. Sereno and Efthimiadis (2018) find that the TSO and the non-TSO investor conduct their capacity optimisation based on different objectives. Since a non-TSO investor maximises profits rather than welfare, the authors show that the optimal capacity of a non-TSO investor will be lower than that of the state-owned TSO.

Doorman and Frøystad (2013) analyse the profitability of two hypothetical interconnectors from Norway to Scotland and England in the years 2010 and 2020. The authors find that in 2010 both interconnectors provide a positive net social welfare, but neither projects are profitable. In other words, the interconnectors are only profitable from a social welfare perspective and will only be developed by a welfare-maximising TSO. Due to lower and more stable electricity prices caused by additional RES generation in Norway and the UK in 2020, only the interconnector to Scotland is socio-economic profitable, and neither interconnectors are profitable for a non-TSO investor. By relying on commercial parties to invest in transmission capacity, Doorman and Frøystad (2013) conclude that some projects which actually increases social welfare may not be realised.

The difference between a TSO-owned and a non-TSO-owned interconnector is less studied, since privately-owned interconnectors are not as common. Similar to Sereno and Efthimiadis (2018), we will investigate how the capacity decision differs between a TSO and a non-TSO investor. However, in contrast to Sereno and Efthimiadis (2018), we will quantify the interconnector congestion rent under different income regulatory regimes.

4. Theory

This chapter outlines the theoretical frameworks relevant for our thesis. First, the chapter illustrates how the merit order determines the supply of electricity by source and how electricity prices are established. Second, the chapter explains how trade affects electricity markets and the social welfare in a market. Lastly, the chapter describes how a welfare-maximising TSO and a non-TSO investor optimise the transmission capacity between two markets.

4.1. The merit order effect

The market clearing price equals the marginal cost of producing the last unit demanded. Specifically, for electricity markets, the electricity price will be equal to the marginal cost of the last power plant being dispatched (Auverlot et al., 2014).

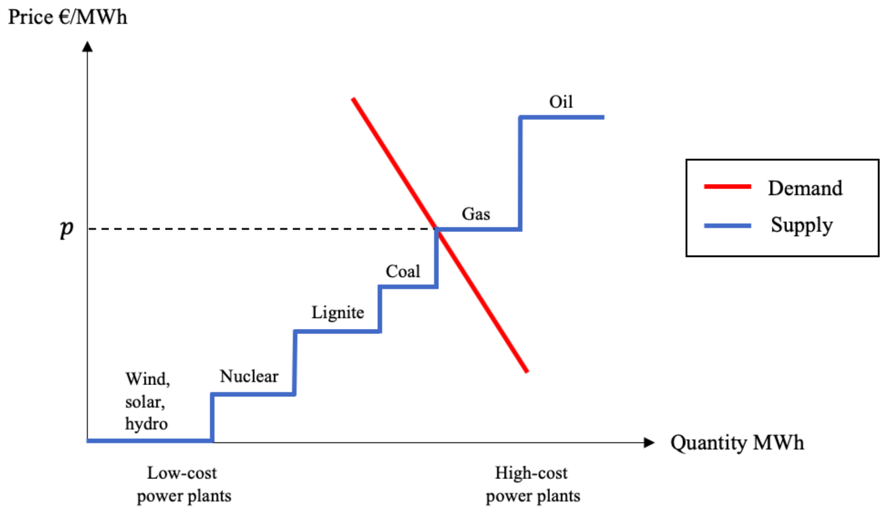

Figure 4.1 – The merit order of a power market by source. Authors' own illustration.

Power plants applying different fuels or technologies will have different marginal cost levels and can be ranked accordingly. Low-cost power plants typically generate electricity from hydro, RES and nuclear, whereas power plants of higher cost levels generate electricity from coal, gas and oil. To meet demand, the generation capacity with the lowest costs will be utilised first and the higher cost generation capacity thereafter (Auverlot et al., 2014). Thus, there is an ascending order of production, which is better known as the merit order. Since the generation capacity with the lowest marginal costs is used first, the overall cost of generating electricity is minimised. This is called the merit order effect (Auverlot et al., 2014). The merit order curve represents the supply curve of electricity in a power market as illustrated in Figure 4.1.

The demand curve is steeply downward-sloping as depicted in Figure 4.1, illustrating that the price elasticity of demand is assumed to be quite inelastic to short-term changes in prices. This assumption is supported by the analysis of Bye and Hansen (2008), who study elasticities in Norway and conclude that there is zero price elasticity of demand in the summer and very low price elasticity of demand in the winter. The equilibrium electricity price p is given where demand equals supply.

Each power market will have a unique supply curve determined by its specific merit order. In the absence of trade between the power markets, each market will have an individual equilibrium electricity price. As illustrated in Figure 4.2, power market A is characterised by a high share of power generation from low-cost power plants and therefore has a relatively low electricity price p^A, whereas market B has a high share of high-cost power generation and a correspondingly relatively high electricity price p^B.

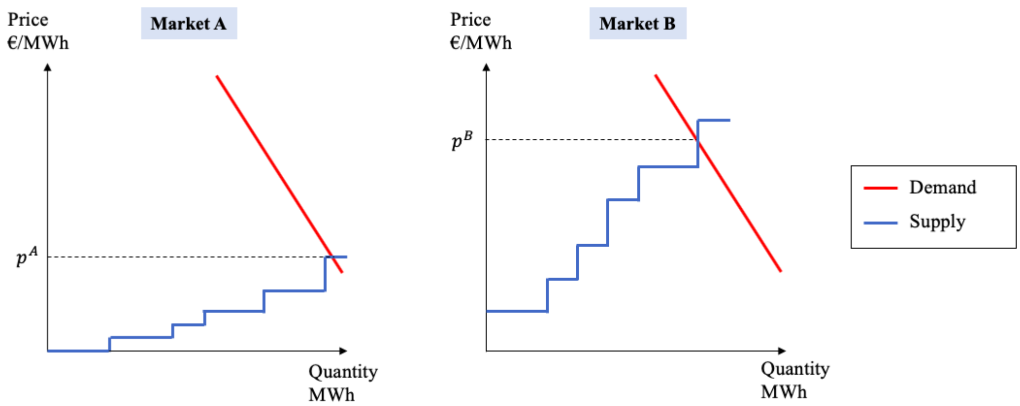

Figure 4.2 – The merit order of a low-cost power market A and a high-cost power market B. Authors' own illustration.

4.2. Trade of electricity

By building interconnectors, which facilitates trade in electricity, high-cost and low-cost power markets will be affected differently. A country will import a good if the price of that good before opening up for trade is relatively higher than the world price of the good, providing lower prices to the consumers. Opposite, if the price of a good before opening up for trade is relatively lower than the world price of that good, a country will export the good.

The high-cost power market B will have a relatively higher price than a neighbouring low-cost power market before opening up for trade. Consequently, market B can benefit from importing electricity at a lower price and leave some of its high-cost generation capacity unused. In other words, market B will "borrow" low-cost generation capacity from the neighbouring market. By importing electricity, market B's supply curve shifts to the right equivalent to the quantity imported. The shift in the supply curve, while holding the demand curve constant, lowers the electricity price in market B from p_0^B to p_1^B, as illustrated in Figure 4.3. In addition, the imported power will replace some of the high-cost power generation of market B. Thus, trade facilitates a more optimal allocation of generation capacity across power markets, in which the low-cost generation capacity is utilised first. (Zakeri et al., 2015)

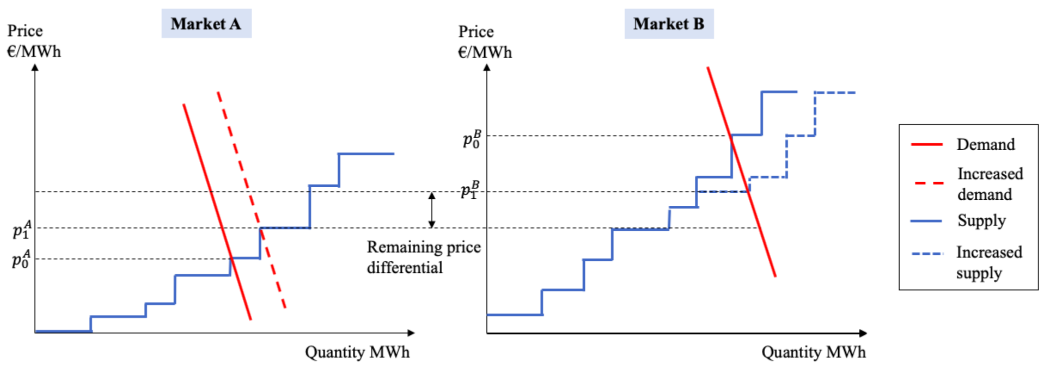

Figure 4.3 – The electricity price convergence due to trade from a low-cost power market A to a high-cost power market B. Authors' own illustration.

Opposite, the low-cost power market A can provide electricity at a relatively lower price than a neighbouring high-cost power market. By allowing for trade in electricity, the neighbouring high-cost power market will demand electricity from market A. As a result, the demand curve of market A will shift to the right equal to the amount of export given by the available transmission capacity between the two markets, as illustrated in Figure 4.3. Subsequently, the electricity price of market A will increase from p_0^A to p_1^A. (Duthaler and Finger, 2008)

In sum, electricity will flow from the low-cost power market towards the high-cost power market and the prices of the respective markets will converge (Zakeri et al., 2015). By opening up for trade the price differential between the power markets narrows from $(p_0^B - p_0^A)$ to $(p_1^B - p_1^A)$. Note that the prices of the power market A and power market B will continue to converge when additional transmission capacity between the two markets allows for more trade in electricity.

The available transmission capacity given in Figure 4.3 is not sufficient to equal prices in the two power markets, constituting a barrier for trade. However, if there are no capacity constraints between power markets, and electricity can be allocated freely from all producers to all consumers across both markets, the marginal cost of production will be equal in market A and market B. Murray (2009) calls this phenomenon the equal lambda criteria, in which the electricity prices in market A and market B will be identical.

4.3. Social welfare

Social welfare, also called socio-economic benefit, is a widely used term to assess how well a market performs (Zakeri et al., 2015). The social welfare is derived from the consumer surplus, the producer surplus and, in the case of cross-border interconnectors, the interconnector wealth. If the capacity of an additional interconnector between two power markets is large enough to impact prices in the respective markets, it will alter the size and the distribution of the social welfare (Turvey, 2006).

The effect of an additional interconnector on the consumer surplus and the producer surplus in the aforementioned low-cost power market A and the high-cost power market B is shown in Figure 4.4. The congestion rent of that additional interconnector is also depicted.

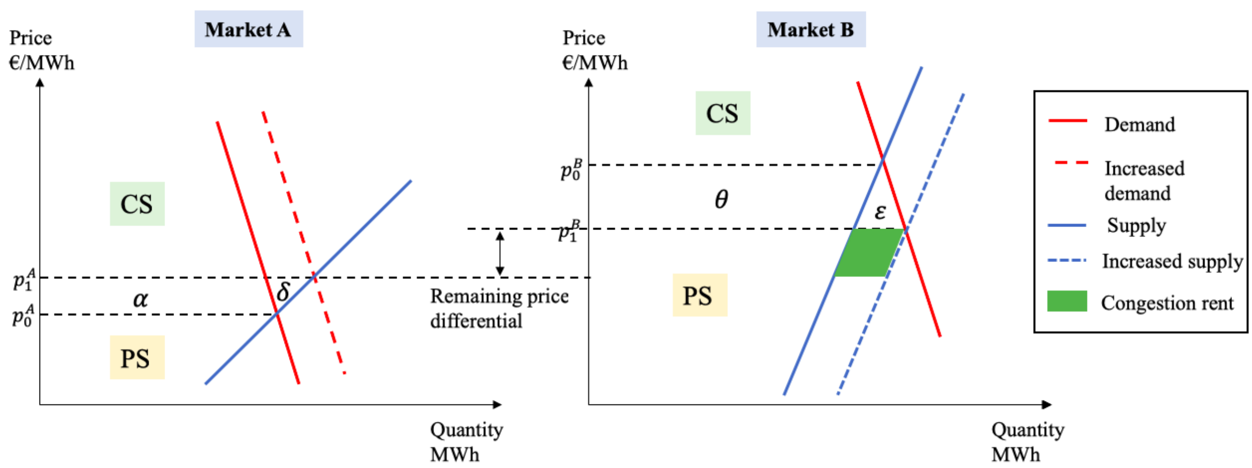

Figure 4.4 – Changes in consumer surplus (CS) and producer surplus (PS) in the low-cost power market A and the high-cost power market B due to an additional cross-border interconnector and the congestion rent of that interconnector. Authors' own illustration.

The consumer surplus is given by the area below the demand curve and above the electricity price. An additional interconnector will mainly affect the consumer surplus through price movements (Pöyry, 2014). In power market A the price increases from p_0^A to p_1^A, which reduces the consumer surplus by α as it becomes costlier for a consumer to use electricity. Whereas in power market B, the price reduction from p_0^B to p_1^B increases the consumer surplus by $\theta + \varepsilon$, since it both becomes less costly to buy electricity and additional electricity is supplied through imports. In addition, the consumer surplus may be altered due to redistributive mechanisms of the specific income regulation of the additional interconnector (Pöyry, 2014).

The producer surplus is given by the area above the supply curve and below the electricity price. Similar to the consumer surplus, an interconnector will mainly affect the producer surplus through the electricity price (Pöyry, 2014). The producer surplus in power market A increases by $\alpha + \delta$ due to higher prices and increased quantity produced. In power market B, lower prices and increased imports lower the producer surplus by θ.

The interconnector wealth is given by the congestion rent captured by the interconnector owner, less the costs for construction and operation of the interconnector (Pöyry, 2014). If a new interconnector is constructed, it may affect the interconnector wealth of an existing interconnector by lowering its congestion rent as prices will converge, called the cannibalism effect (Pöyry, 2014). Further, the redistributive mechanism of an interconnector income regulation may alter the interconnector wealth.

4.4. Effect of additional renewable energy sources on the merit order

If generation capacity increases in a power system, the supply curve shifts to the right, but changes in the shape of the curve will depend on what type of capacity is added. By adding new capacity of intermittent renewable energy generation such as wind and solar, which has a low to zero marginal cost, the supply curve will shift as illustrated in Figure 4.5. If demand remains unchanged, the effect will be a lower electricity price p^{RES} in the power market. However, by adding high-cost generation capacity with a marginal cost higher than the initial price balancing supply and demand, there would be no effect on the electricity price.

Several studies have found that additional power generation from RES replaces production of electricity from sources with higher marginal cost, and causes electricity prices to fall (Jaehnert et al., 2013, Würzburg et al., 2013). The effect of increased RES in a power market will also impact the electricity price in connected power markets through cross-border interconnectors. In addition, since increased generation from RES will affect prices and the supply curve in a power market, it will subsequently impact the consumer and producer surplus.

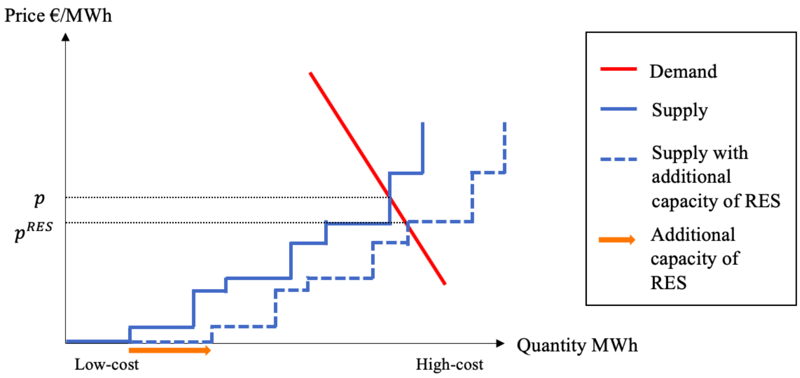

Figure 4.5 – Additional RES generation capacity on the merit order. Authors' own illustration.

4.5. Optimal cross-border transmission capacity

The optimal amount of cross-border transmission capacity built will depend on the type of investor. A TSO, a so-called social planner, will choose to build transmission capacity k such that it maximises social welfare (Sereno and Efthimiadis, 2018). Thus, for a TSO in a low-cost electricity market A, the benefits from using electricity $B(q_D)$ at home and the value of the exported electricity to the high-cost electricity market B, given by $p^B(q_S - q_D)$, must be larger than costs related to production $C(q_S)$ and the investment cost of building more transmission capacity $h(k)$.

$$\begin{aligned} \max_{q_D, q_S, k} \quad & B(q_D) - C(q_S) + p^B(q_S - q_D) - h(k) \\ \text{s.t.} \quad & q_S - q_D \leq k \end{aligned} \tag{4.1}$$

Note that if the quantity of electricity demanded q_D is larger than the quantity supplied q_S, the TSO will import electricity instead of export, making the third term negative. To simplify, it is assumed that all of the available transmission capacity is used, thus the side constraint holds with equality $q_S - q_D = k$. Therefore, the TSO will maximise the social welfare according to the optimisation problem in equation (4.2).

$$\max_{q_D, k} \quad B(q_D) - C(q_D + k) + p^B k - h(k) \tag{4.2}$$

The price in the high-cost market B, denoted p^B, is assumed to be exogenous and will thus not be affected by increased trade with market A. This assumption is a simplification, as the electricity price in a high-cost power market will generally be affected by increased trade with a low-cost power market.

The optimal quantity of electricity demanded q_D^* in market A is given by the partial derivative of equation (4.2) with respect to q_D set equal to zero.

$$\begin{aligned} \frac{\partial}{\partial q_D} = B^{'}(q_D) - C^{'}(q_D + k) = 0 \\ B^{'}(q_D) = C^{'}(q_D + k) \end{aligned} \tag{4.3}$$

The optimal quantity of electricity demanded q_D^* is given where the marginal benefits $B^{'}(q_D)$ equals the marginal costs $C^{'}(q_D + k)$ as shown by the equation (4.3) and in the Figure 4.6. The marginal cost term $C^{'}(q_D + k)$ provides the electricity price in market A, p_1^A.

The optimal cross-border transmission capacity built by a welfare-maximising TSO k_{TSO}^* is given by the partial derivative of equation (4.2) with respect to capacity k set equal to zero.

$$\begin{aligned} \frac{\partial}{\partial k} = -C^{'}(q_D + k) + p^B - h^{'}(k) = 0 \\ p^B - p_1^A = h^{'}(k) \end{aligned} \tag{4.4}$$

The TSO will build capacity k_{TSO}^* until the point where the marginal investment cost $h^{'}(k)$ is equal to the price differential between market A and market B as given by the left hand side of the equation (4.4). The left hand side of equation (4.4) is illustrated as φ in Figure 4.6. It is assumed that $h(k)$ is linear in costs.

If there is unlimited transmission capacity between market A and market B, the electricity price in market A p_∞^A will become equal to the exogenous price in market B p^B. Thus, the left hand side of equation (4.4) becomes zero. Yet, the right hand side of equation (4.4) is not zero. Since the TSO incorporates the marginal investment cost in its optimisation problem, unlimited transmission capacity will never be built.

Inadequate transmission capacity between two markets can create an inefficient allocation of resources. This inefficiency creates a cost for the society, called a dead weight loss (DWL). A welfare-maximising TSO wants to minimise the DWL. However, since a welfare-maximising TSO will not build unlimited capacity, some DWL will remain.

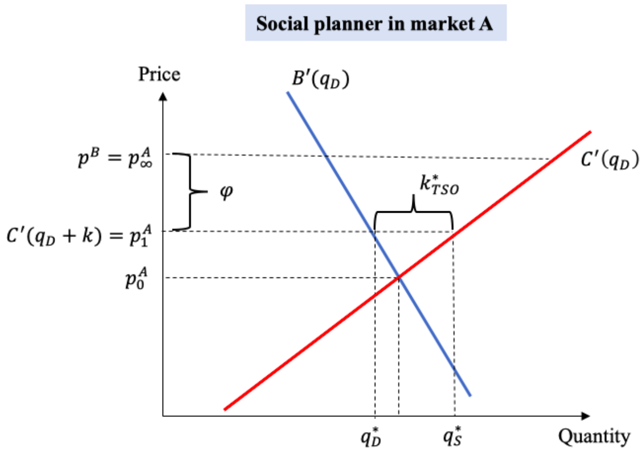

Figure 4.6 – The optimal cross-border transmission capacity k^*_{TSO} of a welfare-maximising TSO. The marginal benefits provide the demand curve and the marginal costs provide the supply curve. Authors' own illustration.

A non-TSO investor will disregard the social welfare and only choose a transmission capacity $k_{non-TSO}$ that maximises the congestion rent of the interconnector.

$$\max_k \quad \pi = (p^B - C^{'}(q_D + k))k - h(k) \tag{4.5}$$

Where p^B is the price in the high-cost market B, $C^{'}(q_D + k)$ is the marginal cost of electricity, i.e. the electricity price in market A, and $h(k)$ is the investment cost of capacity.

The optimal transmission capacity of a non-TSO investor is given by the partial derivative of equation (4.5) with respect to k set equal to zero.

$$\begin{aligned} \frac{\partial \pi}{\partial k} = p^B - C^{'}(q_D + k) + (-C^{''}(q_D + k))k - h^{'}(k) = 0 \\ p^B - C^{'}(q_D + k) - C^{''}(q_D + k)k = h^{'}(k) \\ p^B - p^A_1 - C^{''}(q_D + k)k = h^{'}(k) \end{aligned} \tag{4.6}$$

A non-TSO investor will build the optimal capacity $k^*_{non-TSO}$ up to the point where the price differential between market A and market B less the additional term $C^{''}(q_D+k)k$ is equal to the marginal investment cost $h^{'}(k)$. Compared to a welfare-maximising TSO, a non-TSO investor will build less transmission capacity equal to the additional term $C^{''}(q_D + k)k$. The optimal capacity of a non-TSO investor is less than that of a welfare-maximising TSO, $k^*_{non-TSO} < k^*_{TSO}$, since the positive externalities of the interconnector, i.e. the benefits, are not captured by the non-TSO investor (Dutton and Lockwood, 2017).

5. Methodology

This chapter presents the methodology applied for the analysis of the thesis. First, the chapter outlines methods to calculate the historical volatility and introduces an approach to quantify the uncertainty of the electricity price differentials using the historical distribution. Thereafter, the TheMA model which is used to simulate future electricity prices is presented and the main assumptions behind the model is given. Finally, a method to calculate the congestion rent of a cross-border interconnector is presented.

5.1. Historical data

The historical data used in this thesis are obtained from Nord Pool's FTP-server. The first data set consists of hourly day-ahead Elspot prices in €/MWh for the Norwegian bidding zone NO5 from the 1st of January 2011 to the 31st of December 2017. The second data set consists of hourly N2EX day-ahead auction prices for the market area Great Britain from the 1th of January 2011 to the 31st of December 2017. The hourly N2EX prices are given in €/MWh from the 5th of February 2014 to the 31st of December 2017, whereas the hourly N2EX prices are only available in £/MWh from the 1th of January 2011 to the 4th of February 2014. The latter prices are therefore converted to euro using the monthly conversion rates shown in Appendix 9.7. For the bidding zone NO5, the day-ahead Elspot prices are preferred over intraday Elbas prices due to a higher trading volume.

5.1.1 *Historical volatility*

The volatility of electricity prices is an indicator of the level of uncertainty related to the prices (Lidderdale and Ryan, 2009). A common technique to quantify the uncertainty of electricity prices is to compute the historical volatility using historical data (Wengler, 2001). Historical volatility is calculated as the standard deviation of electricity prices over a specific time period. This technique is preferred in this thesis due to the availability of historical data.

The analysis will investigate the historical volatility of the hourly electricity price itself p_t, the first difference of the electricity price $p_t - p_{t-1}$, the natural logarithm of the electricity price itself $\ln p_t$ and the natural logarithm of the first difference of electricity prices $\ln p_t - \ln p_{t-1}$ of the bidding zone NO5 and the market area Great Britain. This is in line with the approach by Lucia and Schwartz (2002), who examine the volatility of the daily Nord Pool system price.

The volatility of the hourly electricity price itself p_t is given by equation (5.1). The electricity price for hour t is p_t, the average hourly electricity price for all observations is $\bar{p} = \frac{\sum p_t}{N}$ and N is the number of observations, i.e. hours, in the data set.

$$\sigma_{\text{hourly}} = \sqrt{\frac{\sum_{t=1}^{N}(p_t - \bar{p})^2}{N-1}} \tag{5.1}$$

The volatility of the first difference of the electricity price $p_t - p_{t-1}$ is given by equation (5.2). The first difference of the hourly electricity price is $x_t = p_t - p_{t-1}$, the average first difference of hourly electricity prices for all observations is $\bar{x} = \frac{\sum x_t}{N-1}$ and N is the number of observations.

$$\sigma_{\Delta\text{hourly}} = \sqrt{\frac{\sum_{t=2}^{N}(x_t - \bar{x})^2}{N-2}} \tag{5.2}$$

The volatility of the natural logarithm of the hourly electricity price itself $\ln(p_t)$ is given by equation (5.3). The natural logarithm of the hourly electricity price for hour t is $\ln p_t$, the average natural logarithm of electricity prices for all observations is $\bar{\ln} p = \frac{\sum \ln p_t}{N}$ and N is the number of observations.

$$\sigma_{\text{ln hourly}} = \sqrt{\frac{\sum_{t=1}^{N}(\ln(p_t) - \bar{\ln}(p))^2}{N-1}} \tag{5.3}$$

The volatility of the first difference of the natural logarithm of the hourly electricity price $\ln p_t - \ln p_{t-1}$ is given by equation (5.4). Where the first difference of the natural logarithm of the hourly electricity price is $y_t = \ln p_t - \ln p_{t-1}$, the average first difference of the natural logarithm of electricity prices for all observations is $\bar{y_t} = \frac{\sum y_t}{N-1}$ and N is the number of observations.

$$\sigma_{\Delta\text{ln hourly}} = \sqrt{\frac{\sum_{t=2}^{N}(y_t - \bar{y_t})^2}{N-2}} \tag{5.4}$$

To be able to compare the historical volatility across power markets, the correlation between the electricity prices of the power markets in question must be accounted for. The correlation coefficient ρ between the electricity prices in the bidding zone NO5 and the market area Great Britain is given by equation (5.5).

$$\rho = \frac{\sum_{t=1}^{N}(p_t^{NO5} - \bar{p}^{NO5})(p_t^{GB} - \bar{p}^{GB})}{\sqrt{\sum_{t=1}^{N}(p_t^{NO5} - \bar{p}^{NO5})^2} \times \sqrt{\sum_{t=1}^{N}(p_t^{GB} - \bar{p}^{GB})^2}} \tag{5.5}$$

The electricity price in NO5 at hour t is p_t^{NO5} and the electricity price in Great Britain at hour t is p_t^{GB}. The average hourly electricity prices in the respective regions are $\bar{p}^{NO5} = \frac{\sum p_t^{NO5}}{N}$ and $\bar{p}^{GB} = \frac{\sum p_t^{GB}}{N}$. N is the number of observations in the data set.

5.1.2 *Range of the price differential*

To quantify some of the uncertainty in the future price differentials, the potential range of the future price differentials is constructed from historical data. The distribution of the historical electricity price differential in absolute numbers provides the estimates for the range of the future price differentials. The distance between the historical median and the historical 5$^{\text{th}}$ percentile is given by λ, whereas the distance between the historical median and the historical 95$^{\text{th}}$ percentile is given by μ, as shown in Figure 5.1. If the historical electricity price differential is normally distributed, λ and μ will be equal.

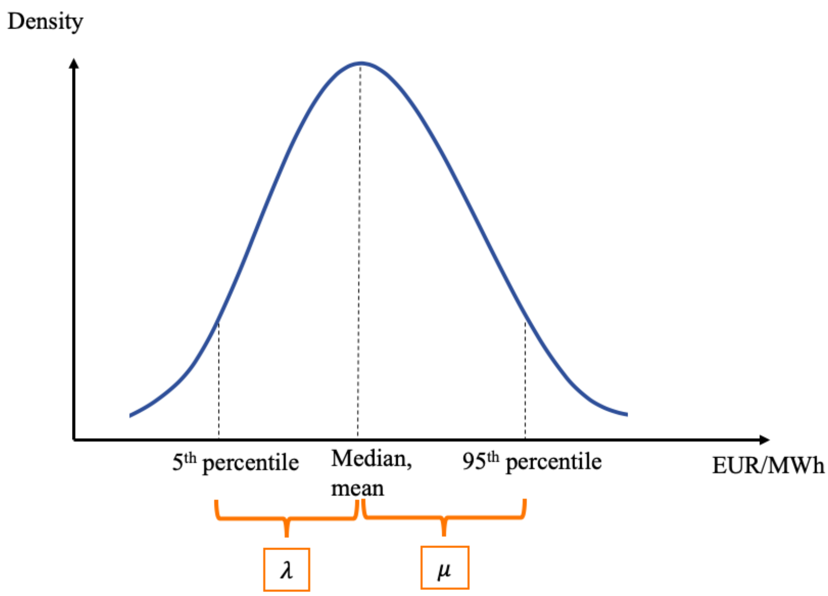

Figure 5.1 – A hypothetical distribution of the historical electricity price differentials in absolute numbers.

The potential range of the future price differential is derived from future price differential in €/MWh and the historical λ and μ. The bottom and the top of the range is given by equation (5.6) and equation (5.7), respectively.

$$\text{Bottom of the range} = \text{Future hourly price differential} - \lambda \tag{5.6}$$

$$\text{Top of the range} = \text{Future hourly price differential} + \mu \tag{5.7}$$

5.2. The TheMA model

THEMA Consulting Group AS (hereafter THEMA) is a consulting firm specialised in the European energy market. THEMA provides market analysis, market design and business strategies to clients within the energy and the electricity sector. Many of THEMA's services are based on their well-known, self-developed TheMA model. The TheMA model is a power market model used to develop price forecasts, scenario analysis and investment evaluations for the European power market. (THEMA, 2018)

The TheMA model simulates future electricity prices for all hours of a year for different price areas and scenarios. The hourly time resolution of the model enables analysis of price volatility by geography. The European power market is highly integrated; thus all relevant markets are represented in the model (THEMA, 2012). This includes the Nordic (except Iceland) and the Baltic states, in addition to Germany, Poland, the Netherlands, Belgium, France, Switzerland, Austria, the Czech Republic, Italy and Spain. (THEMA, 2018)

The TheMA model performs an optimisation of a simulated power market by minimising system costs, while taking the transmission capacity between price areas and a set of additional constraints into account. The input parameters of the model include power plant capacities, fuel prices, CO2 prices, demand profiles for each price area, annual inflow to hydro reservoirs and transmission capacities. Data sources for the TheMA model originate from national regulators, TSOs, ministries and in-house analysis, amongst others. (THEMA, 2018)

The analysis of this thesis is based on the future hourly electricity prices in 2018 €/MWh in the bidding zone NO5 in Norway and in the market area Great Britain for a sample of years between 2019 and 2045 simulated by the TheMA model for THEMA's baseline scenario. The missing years have been linearly interpolated. Additional output from the TheMA model includes power generation by plant and fuel technology, trade flows, welfare economic indicators and the electricity mix for different price areas.

5.2.1 *Assumptions behind the baseline scenario of THEMA*

The main assumptions related to fuel prices, carbon prices, electricity demand and supply and cross-border transmission capacity for the baseline scenario of THEMA are summarised in Figure 5.2.

	Description
Baseline scenario	• Increasing fuel prices beyond 2021 • Increasing carbon prices • Some growth in demand, most in the UK • Strong development in RES in both Norway and the UK • Increasing transmission capacity between Norway and the UK

Figure 5.2 – Main assumptions of the baseline scenario of the TheMA model for the period 2019 to 2045.

In the baseline scenario it is assumed that fuel prices will decrease towards 2021, before they increase until 2030. For the period until 2021, THEMA uses the forward market to set prices for gas and other fuels. The carbon prices are expected to increase over time, which will cause the carbon price floor to not be binding in the long term.

The demand for electricity in the Nordics is expected to increase slightly towards 2045, as illustrated in Appendix 9.8. In the UK, it is expected that the electricity demand will increase over the period, as shown in Appendix 9.9.

The electricity supply mix of both Norway and the UK is expected to change from 2019 to 2045. In Norway, the increase in electricity generation will almost only be driven by additional wind power, as shown in Appendix 9.8. As illustrated in Appendix 9.9, the UK electricity generation from coal is expected to be phased out by 2025 and the electricity generation from gas will be reduced after 2025. The UK will increase its RES generation towards 2045, mainly from wind power and some solar power. THEMA's RES generation assumptions for Norway and the UK are bullish compared to the industry average.

The assumptions behind the cross-border transmission capacities in the TheMA model are based on the 10-Year Network Development Plan (TYNDP) from ENTSO-E. The baseline scenario assumes that the NSL cable between the bidding zone NO2 in Norway and the UK will commence operation the 1st of January 2021, whereas the NorthConnect cable between the bidding zone NO5 and the UK will commence operation the 1st of January 2026. In addition, planned interconnectors from Sweden and Denmark are included in the assumptions, as presented in the countries respective grid development plans.

5.3. Congestion rent

The congestion rent of an interconnector between bidding zone NO5 and the market area Great Britain will be determined by the price differential between the two areas $p_t^{NO5} - p_t^{GB}$ and the available transmission capacity of the interconnector during an hour t. This approach is in line with those put forward by Duthaler and Finger (2008), Pöyry (2014) and Turvey (2006). The annual congestion rent (CR) of a cable is given by equation (5.8).

$$CR = \sum_{t=1}^{n} \Big(((1 - ts) \times TC) \times \big|(p_t^{NO5} - p_t^{GB})\big| \Big) \tag{5.8}$$

Where p_t^{NO5} is the electricity price in the bidding zone NO5 during an hour t, p_t^{GB} is the electricity price in the market area Great Britain during an hour t, and n is the number of hours in a year. The available total capacity of an interconnector is given as the total capacity TC less the transmission loss ts. In this thesis a transmission loss of 5 % is assumed, which is the transmission loss given in the concession application of NorthConnect (2017). Trade will only occur if there is a price differential between the bidding zone NO5 and the market area Great Britain. Thus, there will be no trade if the price differential is zero.

Note that the price differential between the two areas is given in absolute numbers to reflect that the congestion rent of the interconnector is earned independently of the direction of the flow of electricity. Further, since the congestion rent is subject to regulation in both power markets it connects, the congestion rent is typically divided in two equal shares between the respective regulatory authorities.

Moreover, it is assumed that all of the capacity of the interconnector is dedicated to trade and no capacity contracts are made. This is an assumption also made by Garcia et al. (2011) for the assessment of the interconnector Nemo Link between the UK and Belgium. We assume that the interconnector flow may change direction from hour to hour, and we disregard any capacity limitations and other limitations of the transformation stations at each end of the cable.

6. Analysis

First, this chapter assesses the historical development of electricity prices in the bidding zone NO5 (hereafter NO5) and in the market area Great Britain (hereafter GB). Second, the simulated future electricity prices in both power markets are presented. Finally, the congestion rent of a 1 400 MW interconnector between NO5 and GB is estimated.

6.1. Analysis of historical electricity prices

The main risk of the interconnector income is related to the electricity price differential between the two power markets the cable connects. It is therefore of interest to assess how the electricity prices in two connected markets have fluctuated historically.

Further, it is important to note that a regression analysis has not been executed to determine which factors that affect electricity prices. However, the analysis is based on frequently stated reasons of why electricity prices fluctuate.

6.1.1 *Historical development of electricity prices in NO5*

The hourly electricity price for NO5 has fluctuated over the sample period from 2011 to 2017, as illustrated by Figure 6.1(a). The average hourly electricity price was 30,43 €/MWh in NO5 for the sample period, as presented in Table 6.1. The maximum hourly electricity price over the period was 210,00 €/MWh and was observed on the 8$^{\text{th}}$ of February 2012, whereas the minimum price was observed the 27$^{\text{th}}$ of October 2014 and amounted to 0,59 €/MWh.

The electricity prices in NO5 have been volatile in the period from 2011 to 2017, as confirmed by the standard deviation. The comparative statistics in Table 6.1 show that the standard deviation of the hourly electricity price was 12,80 for the period as a whole. This results in a daily volatility of 62,71[1] for the sample period. Lucia and Schwartz (2002) find that the standard deviation of the daily Nord Pool system price is 66,37 for the period 1993 to 1999. Due to the similarity between the electricity price in NO5 and the Nord Pool system price, our results are comparable with those of Lucia and Schwartz (2002).

[1]The volatility of daily electricity price is $12,80 \times \sqrt{24} = 62,71$.

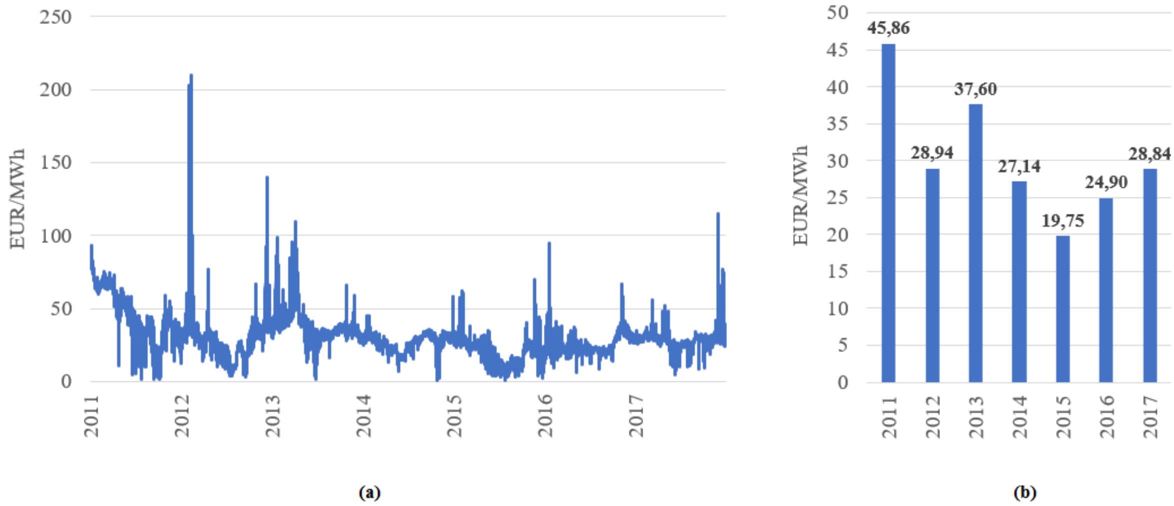

Figure 6.1 – **(a)** The historical development of the hourly electricity prices in NO5 in €/MWh from 2011 to 2017. **(b)** The historical development of the average annual electricity price in NO5 in €/MWh for the years 2011 to 2017.

The NO5 electricity prices have shown two distinct statistical features. The first statistical feature of the electricity prices in NO5 is that they have exhibited spikes, i.e. abnormally large price variations. The kurtosis and skewness presented in Table 6.1 confirms the electricity price spikes. A kurtosis larger than 3 implies that the distribution of prices is leptokurtic and that extreme values occur relatively often. Over the period from 2011 to 2017, a kurtosis of 9,04 has been observed for the electricity prices in NO5, which show that extreme electricity prices have occurred relatively frequent. This is in line with the conclusions drawn by Lucia and Schwartz (2002), who find a kurtosis of 3,5 for the Nord Pool system price. A positive skewness for a price series suggest that high extreme values of prices are more probable than low extreme values (Lucia and Schwartz, 2002). The positive skewness of 1,43 observed for the hourly electricity price in NO5 confirms that there is a greater probability for high extreme prices than low extreme prices. The rejection of normality in the distribution of the electricity prices in NO5 over the sample period is verified by the Jarque-Bera test in Appendix 9.10.

The relatively large, but short-lived, spikes observed in Figure 6.1(a) confirms this statistical feature. This is in line with the results of Nomikos and Soldatos (2010), who assess the Nord Pool power market. The authors find spikes in electricity prices and argue that they are caused by fluctuations related to weather, transmission failures and generation outages. According to Nomikos and Soldatos (2010), these price spikes are usually short-lived and the electricity prices will return to their normal levels as soon as the weather is stabilised and the outage is fixed.

Series	N. Obs.	Mean	Median	Min.	Max.	Std. Dev	Skew.	Kurt.
A: All seasons								
p_t	61 365	30,43	29,31	0,59	210,00	12,80	1,43	9,04
$p_t - p_{t-1}$	61 364	-0,001	-0,04	-151,61	115,46	2,26	-0,09	667,20
$\ln p_t$	61 365	3,32	3,38	-0,53	5,35	0,46	-1,24	7,35
$\ln p_t - \ln p_{t-1}$	61 364	-0,00002	-0,001	-1,59	1,78	0,07	1,39	92,63
B: Cold season								
p_t	35 661	33,76	31,04	0,59	210,00	13,17	1,83	10,43
$p_t - p_{t-1}$	35 660	-0,002	-0,05	-151,61	115,46	2,77	-0,31	507,95
$\ln p_t$	35 661	3,45	3,44	-0,53	5,35	0,39	-1,22	11,55
$\ln p_t - \ln p_{t-1}$	35 660	-0,00003	-0,002	-2,36	1,78	0,06	-0,95	171,95
C: Warm season								
p_t	25 704	25,82	24,93	1,03	63,78	10,66	0,47	3,56
$p_t - p_{t-1}$	25 703	-0,0009	-0,03	-22,26	33,88	1,30	1,73	69,06
$\ln p_t$	25 704	3,15	3,22	0,03	4,16	0,49	-1,17	5,17
$\ln p_t - \ln p_{t-1}$	25 703	-0,00002	-0,001	-1,42	2,02	0,08	2,34	87,91

Table 6.1 – Descriptive statistics of the hourly electricity price in €/MWh for NO5 for the period 2011 to 2017. The cold season is from October through April, and the warm season from May through September.

The effect of large fluctuations in the NO5 electricity prices is smoothed out when aggregating the hourly electricity prices to average annual electricity prices. However, there are still considerable variation as illustrated in Figure 6.1(b). The average annual electricity price in NO5 has varied over the sample period between a minimum of 19,75 €/MWh in 2015 and a maximum of 45,86 €/MWh in 2011, a difference of 26,11 €/MWh or 132,2 %.

The second statistical feature of the NO5 electricity prices is that they have exhibited a mean reversion. This implies that the electricity prices have had a tendency to fluctuate around the equilibrium price. The augmented Dickey-Fuller test for stationarity is executed on the electricity price itself, see Appendix 9.12. The dependency on previous prices has been accounted for by including six lags of prices, see Appendix 9.11. The presence of a unit root is rejected, which confirms that the electricity prices in NO5 have been weakly stationary. Thus, the NO5 prices have been mean reverting, which is confirmed for the electricity prices in the Nord Pool markets by Lucia and Schwartz (2002) and Nomikos and Soldatos (2010).

Over the sample period there has been a clear seasonal pattern in the hourly electricity prices for NO5, with higher observed prices during the cold season (October-April) and lower observed prices during the warm season (May-September). Specifically, the average price for the cold season was 33,76 €/MWh, whereas the average price for the warm season was 25,82 €/MWh (see Panel B and Panel C in Table 6.1). Thus, the average electricity price for the cold season was 30,8 % higher than that of the warm season. This seasonal pattern is in line with the results of Lucia and Schwartz (2002), who find that the average daily system price over the period 1993 to 1999 is higher in the cold season than in the warm season.

The standard deviation of the hourly electricity price was 13,17 in the cold season and 10,66 in the warm season as presented in Table 6.1. Thus, the colder season displayed a lower degree of stability of the electricity prices than the warm season. This may indicate that variation in temperatures affect prices more during winter than summer. However, our findings are opposite to the results of Lucia and Schwartz (2002), who find a lower standard deviation of the cold season than of the warm season and conclude that the average daily Nord Pool system price exhibits a higher degree of stability in the cold season compared to the warm season. According to Johnsen et al. (1999), electricity prices in the cold season should exhibit a lower price volatility since the electricity prices are less subject to shocks on the supply side as the hydroelectric generation during winter will mainly rely on the withdrawal of water from the reservoirs.

6.1.2 *Historical development of electricity prices in Great Britain*

The development in the hourly electricity price for GB in the period from 2011 to 2017 is illustrated in Figure 6.2(a). The average hourly electricity price in GB was 53,99 €/MWh in the sample period, as presented in Table 6.2. The hourly electricity price in GB varied from a minimum of 1,80 €/MWh observed on the 7$^{\text{th}}$ of June 2017 to a maximum of 1174,92 €/MWh observed on the 9$^{\text{th}}$ of September 2016.

Also in GB the electricity prices have historically been highly volatile, as confirmed by the standard deviation in Table 6.2. The volatility of the hourly electricity price itself was 19,49 for the sample period, which is higher than the hourly price volatility for NO5 of 12,80. Thus, electricity prices in GB have exhibited a higher degree of volatility in the period from 2011 to 2017 than the electricity prices in NO5. The electricity price structure of NO5 and GB presented

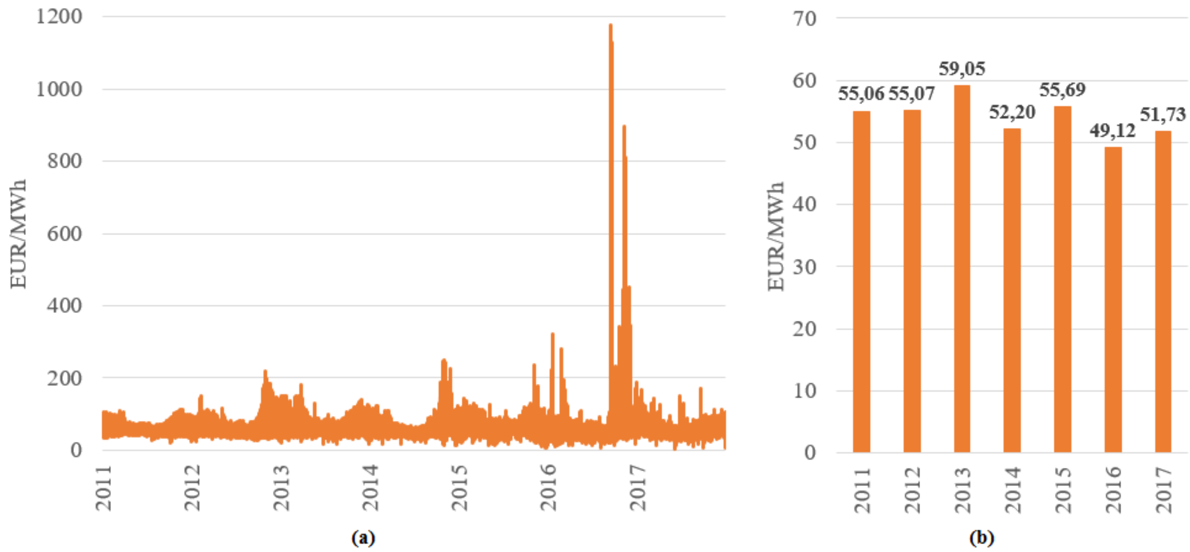

Figure 6.2 – **(a)** The historical development of the hourly electricity prices in Great Britain in €/MWh from 2011 to 2017. **(b)** The historical development of the average annual electricity prices in Great Britain in €/MWh for the years 2011 to 2017.

in Appendix 9.13 reveals that the GB electricity prices exhibited larger variations within a day and a week than NO5, with two distinct price spikes each day.

The increased share of electricity generation from intermittent RES in GB may have contributed to the observed high price volatility in the sample period, especially in the later years. As presented in Appendix 9.2, GB's electricity generation from RES have increased from 4,4 % in 2011 to 18,3 % in 2017. This is in line with Pöyry (2014), who finds that the electricity price volatility increases as the share of generation from intermittent electricity sources expands.

Similar to the electricity prices in NO5, the GB electricity prices have shown two distinct statistical features. The first statistical feature is that the GB electricity prices have exhibited spikes over the sample period. From 2011 to 2017, a kurtosis of 695,49 have been observed for the electricity prices in GB, which show that the distribution of prices was leptokurtic. Consequently, extreme electricity prices have occurred relatively often in GB. The skewness observed for the hourly electricity price is 16,22 for the sample period, which confirms that high extreme prices have been more frequent than low extreme prices in GB. The rejection of normality in the distribution of GB electricity prices over the sample period is verified by the Jarque-Bera test in Appendix 9.10.

Extreme price spikes have been observed in GB, especially during the last quarter of 2016, as

Series	N. Obs.	Mean	Median	Min.	Max.	Std. Dev	Skew.	Kurt.
A: All seasons								
p_t	61 365	53,99	52,00	1,80	1174,92	19,49	16,22	695,49
$p_t - p_{t-1}$	61 364	-0,0002	-0,4	-822,18	1116,11	15,97	4,64	968,97
$\ln p_t$	61 365	3,95	3,95	0,59	7,07	0,27	0,26	8,74
$\ln p_t - \ln p_{t-1}$	61 364	-0,0000	-0,008	-2,23	2,99	0,17	0,50	12,61
B: Cold season								
p_t	35 661	55,66	52,71	5,14	894,70	19,72	9,48	292,66
$p_t - p_{t-1}$	35 660	-0,0003	-0,53	-665,44	754,20	17,52	3,89	424,06
$\ln p_t$	35 661	3,97	3,95	1,64	6,80	0,28	0,45	7,65
$\ln p_t - \ln p_{t-1}$	35 660	-0,0000	-0,01	-1,72	2,04	0,19	0,59	10,08
C: Warm season								
p_t	25 704	51,85	50,97	1,80	1174,92	18,96	27,22	1385,40
$p_t - p_{t-1}$	25 703	-0,0002	-0,21	-822,18	1116,11	13,51	6,48	2844,67
$\ln p_t$	25 704	3,91	3,93	0,59	7,07	0,26	-0,16	10,67
$\ln p_t - \ln p_{t-1}$	25 703	-0,0000	-0,005	-2,23	2,99	0,14	0,15	19,24

Table 6.2 – Descriptive statistics of the hourly electricity prices in €/MWh in GB for the period 2011 to 2017. The cold season is from October through April, and the warm season from May through September.

illustrated in Figure 6.2(a). The price spikes in 2016 were partly caused by foreign exchange movements, fuel price increase and the tightness of capacity margins in the GB power system (Ward and Unwin, 2017).

The effect of large price fluctuations is smoothed out when aggregating the GB hourly electricity prices to average annual electricity prices. The average annual electricity price in GB, shown in Figure 6.2(b), has varied between a minimum of 49,12 €/MWh in 2016 and a maximum of 59,05 €/MWh in 2013, a difference of 9,93 €/MWh or 20,2 %. Thus, the average annual electricity price has varied substantially less between years in GB than in NO5, where the difference was 26,11 €/MWh or 132,2 %.

The second statistical feature of the GB electricity prices is the mean reversion of prices during the sample period. The augmented Dickey-Fuller test for stationarity is executed on the electricity price itself, see Appendix 9.12, and includes three lags of prices to account for the dependency on previous prices, see Appendix 9.11. The presence of a unit root is rejected, which confirms that the electricity prices in GB have been weakly stationary. Thus, the GB electricity prices have been mean reverting in the sample period, similar to the electricity prices in NO5.

The descriptive statistics in Table 6.2 show that the average hourly electricity price during the cold seasons was 55,66 €/MWh. This was 7,3 % higher than the average hourly price in the warm seasons of 51,85 €/MWh. Similar to NO5, GB experienced on average higher electricity prices during the cold months than during the warmer months. However, in NO5 the difference between the average electricity price in the cold and warm season was 30,8 %. Thus, the GB prices have exhibited a less clear seasonal pattern than NO5 during the sample period. This is confirmed in Appendix 9.14, which show that the GB electricity prices have exhibited less of a seasonal pattern than NO5 in most of the years.

The standard deviation of the GB hourly electricity price was 19,72 in the cold season and 18,96 in the warm season for the sample period. Thus, there was no great difference between the two seasons in terms of price volatility in GB. The GB electricity prices have not fluctuated over the season as the electricity prices in NO5 over the period. The GB electricity prices have instead exhibited short-term fluctuations as shown in Appendix 9.13, which are more common for electricity prices in thermal power markets.

By assessing the historical monthly volatility of electricity prices in GB during the sample period, it appears that succeeding months have similar price volatility (see Appendix 9.15). In particular, the months from April through September and October through March exhibit similar price volatility, in which the warmer months tend to have a lower price volatility than the colder months. However, as presented in Table 6.2, a large difference between the hourly price volatility of the cold and warm season was not observed in GB for the sample period. Our findings suggest that the month April should be included in the warm season, and not in the cold season. We have therefore chosen to include April in the warm season as a sensitivity analysis, which is presented in Appendix 9.16. By including April in the warm season, the standard deviation of the warm season decreases from 18,96 to 18,18 in GB, whereas the standard deviation of the cold season increases from 19,72 to 20,55. The sensitivity analysis indicates a larger difference in price volatility between warm and cold season in GB than what was initially found.

6.1.3 *Correlation of historical electricity prices in NO5 and Great Britain*

The degree of correlation between the historical hourly electricity prices in NO5 and GB was 0,20 over the period from 2011 to 2017, as presented in Table 6.3. Power markets are closely related if the correlation coefficient is higher than $|0,50|$ (Boisseleau and Hewicker, 2004). Consequently, the power markets NO5 and GB are not closely related. A potential reason may be that low prices in GB are typically caused by high wind generation, whereas low prices in NO5 are caused by high inflow to hydro reservoirs (NorthConnect, 2017). Although Norway have had some electricity generation from wind historically (see Appendix 9.1), studies show that electricity generation from wind in connected power markets are generally not perfectly correlated (Spiecker et al., 2013). Specifically, the wind power generation in Norway and the UK are only moderately correlated with a time delay (NorthConnect, 2017).

	GB	NO5
GB	1	
NO5	0,20	1

Table 6.3 – The hourly electricity price correlation coefficient of the power markets NO5 and Great Britain over the period 2011 to 2017 as a whole.

The correlation coefficient between NO5 and GB found in this thesis is of the same magnitude as the correlation coefficient of 0,20 between the bidding zone NO1 in Norway and the EEX power market in Germany for the period April to December 2005 (Bobinaite et al., 2006). Due to the similarity between NO1 and NO5, and that both GB and the EEX power market in Germany are thermal power markets with significant proportion of RES generation, the findings are comparable.

It is of interest to assess if the correlation of the power markets NO5 and GB varies over the sample period. The correlation coefficient between NO5 and GB for each year between 2011 and 2017 are presented in Appendix 9.17. The two power markets exhibited the lowest degree of correlation in 2015, with a correlation coefficient of 0,10, and the highest degree of correlation in 2017, with a correlation coefficient of 0,37. Thus, the correlation coefficient for hourly electricity prices in the two power markets was below $|0,50|$ in all years.

In sum, the power markets NO5 and GB are not closely correlated. Consequently, it is possible to compare historical volatility across the two power markets without getting biased results.

6.1.4 *Historical price differential between NO5 and Great Britain*

The historical development of the hourly electricity price differential[2] between NO5 and GB is presented in Figure 6.3(a) and (b). The average annual hourly price differential has varied between a minimum of 16,13 €/MWh in 2011 and a maximum of 35,99 €/MWh in 2015, a difference of 19,86 €/MWh or 123,1 %.

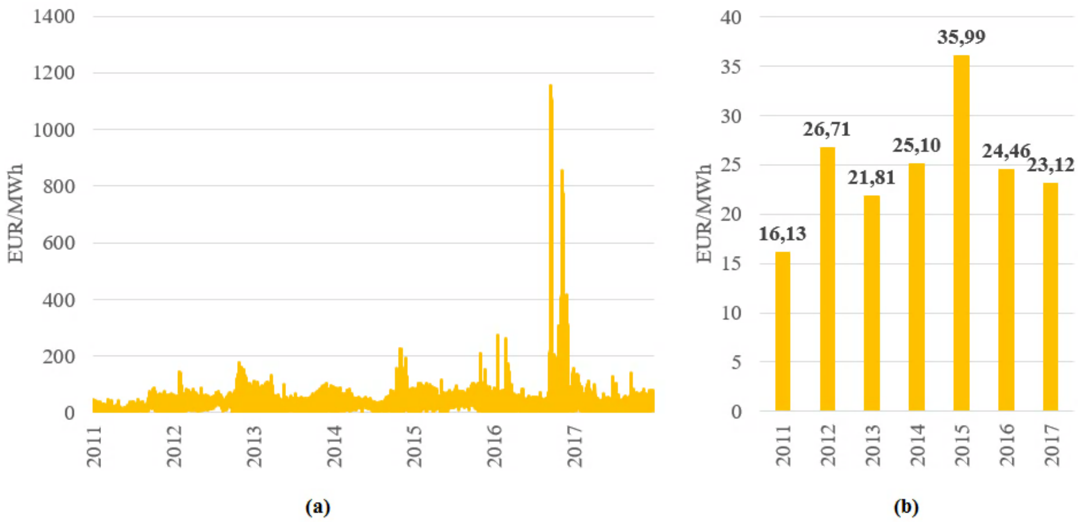

Figure 6.3 – **(a)** The historical development of the hourly electricity price differential between NO5 and Great Britain in €/MWh from 2011 to 2017. **(b)** The historical development of the average annual electricity price differential between NO5 and Great Britain in €/MWh for the years 2011 to 2017.

The average electricity price differential between NO5 and GB was 24,71 €/MWh over the period from 2011 to 2017, as presented in Table 6.4. The largest price differential between NO5 and GB during the sample period was 1154,41 €/MWh, which occurred in 2016. However, such extreme price differentials were limited to only a few hours over the seven-year period, as shown in Figure 6.3(a). The electricity prices in NO5 and GB were never identical between 2011 and 2017. Nevertheless, the minimum price differential was approximately zero. In practice, an approximately zero price differential would not incentivise trade.

The distributions of the hourly price differential between NO5 and GB for each year between 2011 and 2017 are presented in Appendix 9.18. The hourly price differential has for all years, except 2016, typically been below ~50 €/MWh. This finding is aligned with the percentiles of the price differential, given in Appendix 9.19. The price differential was below 52,36 €/MWh in 95 % of the observations. On the other hand, the price differential between NO5 and GB

[2] The historical price differential is given in absolute numbers.

Series	N. Obs.	Mean	Median	Min.	Max.	Std. Dev	Skew.	Kurt.
A: All seasons								
$\|z_t\|$	61 365	24,71	22,09	0,002	1154,41	19,75	15,38	656,58
$\|z_t\| - \|z_{t-1}\|$	61 364	-0,0002	-0,42	-822,08	1116,10	15,81	4,92	1007,52
B: Cold season								
$\|z_t\|$	35 661	23,65	21,07	0,003	835,44	19,02	9,82	308,29
$\|z_t\| - \|z_{t-1}\|$	35 600	-0,0004	-0,51	-665,23	761,37	17,33	4,22	444,60
C: Warm season								
$\|z_t\|$	25 704	26,18	23,91	0,002	1154,41	20,63	21,51	1003,48
$\|z_t\| - \|z_{t-1}\|$	25 703	0,0006	-0,29	-822,08	1116,10	13,43	6,62	2910,64

Table 6.4 – Descriptive statistics of the hourly electricity price differential in €/MWh between NO5 and Great Britain for the period 2011 to 2017. The absolute price differential itself is $|z_t| = p_t^{NO5} - p_t^{GB}$ for hour t. The cold season is from October through April, and the warm season from May through September.

exceeded 13,83 €/MWh for 75 % of the observations. Thus, there has been a substantial price differential between NO5 and GB for a large share of the observations during the sample period.

The kurtosis of 656,58, presented in Table 6.4, show that extreme price differentials have occurred during the sample period. The positive skewness of 15,38 confirms that high extreme price differentials have been more frequent than low extreme price differentials. The rejection of normality in the distribution of the price differential over the sample period is verified by the Jarque-Bera test in Appendix 9.10. The distribution of the price differential is positively skewed, as shown by histogram (c) in Appendix 9.20. The positive skewness is illustrated by a longer distance of 30,27 €/MWh between the 95$^{\text{th}}$ percentile and the median than the distance of 17,97 €/MWh between the 5$^{\text{th}}$ percentile and the median (see Appendix 9.21).

The average price differential was 23,65 €/MWh for the cold season and 26,18 €/MWh for the warm season. Thus, there has been a higher price differential during the warmer months than the colder months in the sample period. This underlines that the electricity prices between NO5 and GB were more different during the warm season than the cold season. Thus, the electricity prices in NO5 and GB do not exhibit a similar seasonal pattern, as shown in Appendix 9.14. One explanation for the lower price differential during winter, is that Norwegian consumers use electricity for heating purposes (Bye and Hansen, 2008). Due to colder temperatures during the winter, Norwegian consumers will demand more electricity in the cold season, which in turn will increase the NO5 electricity prices towards the GB electricity prices.

6.2. Analysis of simulated future electricity prices

The simulated future average annual electricity prices for NO5 and GB between 2019 and 2045 from THEMA's baseline scenario are illustrated in Figure 6.4. The average annual electricity price in NO5 is expected to vary between a minimum of 33,03 €/MWh in 2035 and a maximum of 44,70 €/MWh in 2019. The average annual electricity price in GB is higher than the average annual electricity price in NO5 for all years, and is expected to vary between a minimum of 47,38 €/MWh in 2022 and a maximum of 66,10 €/MWh in 2019.

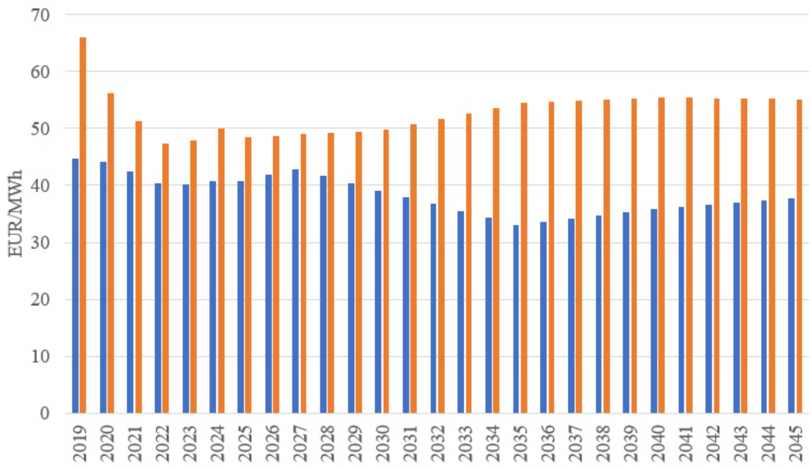

Figure 6.4 – The simulated average annual electricity prices in NO5 (blue) and Great Britain (orange) in 2018 €/MWh from 2019 to 2045. The years between 2025, 2027, 2030, 2035, 2040 and 2045 have been linearly interpolated.

As illustrated in Figure 6.4, the simulated electricity prices in NO5 and GB are expected to differ in the future. This is due to the difference in demand, supply and electricity mix between the two power markets. The GB electricity price is initially set by the marginal cost of coal. However, the GB is expected to continue to decrease its electricity generation from coal, which is assumed to be phased out completely by 2025. Thereafter, the GB electricity price will be set by the relatively higher marginal cost of gas. The merit order curves of GB for the years 2019 and 2030, shown in Appendix 9.22, illustrate the change from coal to gas. Further, it is anticipated that GB will increase its electricity generation from RES, which has a low to zero marginal cost, as indicated by the merit order curves of GB. Since electricity generation from RES have a low to zero marginal cost, it will partly contribute to lower the GB electricity price.

Opposite, NO5 is expected to mainly generate electricity from the low marginal cost capacity of hydroelectricity in the future, as indicated in Appendix 9.8. Thus, the average annual electricity price in NO5 will be lower and vary less than the average annual electricity price in GB, especially until 2025, as shown in Figure 6.4. Although the share of wind power generation will increase in Norway, wind power generation between Norway and UK are only moderately correlated with a time delay (NorthConnect, 2017).

The future average annual electricity price differentials[3] between NO5 and GB are depicted in Figure 6.5. The price differentials between NO5 and GB are expected to be substantial, with an average of 20,15 €/MWh over the period from 2019 to 2045. This is similar to the findings of Pöyry (2014), who argue that the large price differential between Norway and the UK is due to the structural differences between a hydro-dominated power market as Norway and a thermal market as the UK, the carbon price floor in the UK and relatively low volatilities in either country (Pöyry, 2014). As indicated in Appendix 9.8 and Appendix 9.9, Norway is expected to generate electricity mainly from low-cost hydroelectric power, whereas GB will rely on thermal high-cost energy sources like gas and coal to generate electricity.

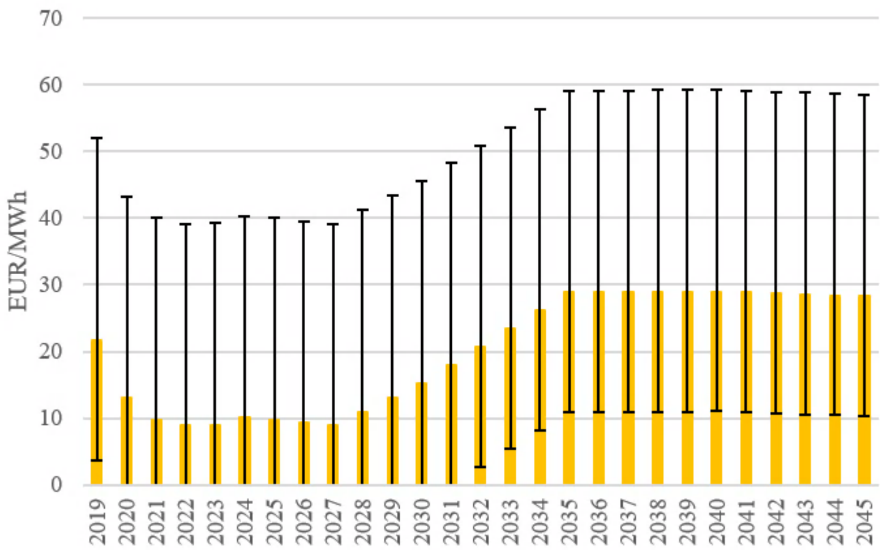

Figure 6.5 – The simulated average annual future price differential between NO5 and Great Britain in 2018 €/MWh from 2019 to 2045 is given by the solid yellow bars. The error bars illustrate the range of the future price differentials, which is based on the distance between the 5th percentile and the 95th percentile of the distribution of the historical price differential between NO5 and Great Britain from 2011 to 2017.

[3]The future price differential is given in absolute numbers.

To quantify the uncertainty in electricity prices, the future simulated price differential is calibrated to include a potential range of future price differentials. The error bars in Figure 6.5 show the range of the future price differentials and are estimated to reflect the positively skewed distribution of historical price differentials in absolute terms from 2011 to 2017. The top of the error bars is given by the simulated hourly electricity price differential plus the historical distance of 30,27 €/MWh between the median and the 95th percentile, as presented in Appendix 9.21. Whereas the bottom of the error bars is given by the simulated hourly electricity price differential less the historical distance of 17,97 €/MWh between the 5th percentile and the median. The range in Figure 6.5 illustrates that the future price differential is likely to differ substantially from the baseline scenario given by the solid yellow bars in the period from 2019 to 2045. The range is estimated to include average annual price differentials of up to 60 €/MWh.

6.3. Analysis of the congestion rent

The Norwegian share (50 %) of the estimated congestion rent of a 1 400 MW cable between N05 and GB commissioned in 2026 is presented in Figure 6.6. The estimated congestion rent will vary between a minimum of €51,4 million and a maximum of €168,4 million between 2026 and 2045. See Appendix 9.23 for an overview. It is assumed that the interconnector can transport electricity either direction, thus the congestion rent is derived both from the export and the import of electricity. For instance, in 2030, the Norwegian share of the congestion rent of a 1 400 MW cable is €88,6 million, in which the congestion rent from NO5 exports was €75,2 million and the congestion rent from NO5 imports was €13,4 million.

The share of the congestion rent derived from GB exports is expected to increase from 13 % in 2026 to 19 % in 2045. This finding is similar to that of Pöyry (2014), who states that the share of export from GB increases from 1 % in 2020 to 13 % in 2040 for the NSL cable between the bidding zone NO2 and GB. Pöyry (2014) argues that this is due to more RES generation capacity being built in GB and that prices are converging between Norway and GB as a reaction to the decrease in carbon price top ups.

The uncertainty in electricity prices will affect the estimated congestion rent. The error bars in Figure 6.6 show the potential range of the estimated congestion rent based on the positive skewed distribution of the historical price differentials. The error bars illustrate that for a specific year the range of the congestion rent is approximately €250 million. Thus, the estimated congestion

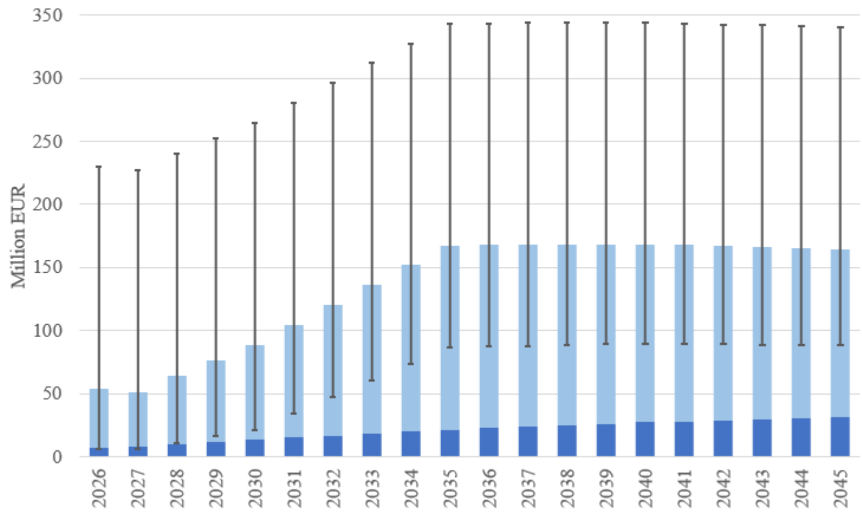

Figure 6.6 – The Norwegian share of the estimated congestion rent of a 1 400 MW cable between NO5 and GB in million 2018 EUR between 2026 and 2045 is given by the solid blue bars. The congestion rent constitutes of exports from NO5 (light blue) and imports to NO5 (dark blue). The error bars illustrate the range of the estimated congestion rent, based on the distance between the 5$^{\text{th}}$ percentile and the 95$^{\text{th}}$ percentile of the distribution of the historical price differential.

rent is likely to vary greatly from the baseline scenario indicated by the solid blue bars in Figure 6.6. Due to the positive skewed distribution of electricity prices, the estimated congestion rent is expected to be larger than in the baseline scenario.

The net interconnector income for a specific year is given by the congestion rent, revenues from capacity markets and balancing revenues less the costs related to capital and operation. It is assumed that all the capacity of the 1 400 MW cable is dedicated to trade on the spot market and the interconnector will therefore only derive its revenues from the congestion rent. Thus, the interconnector is assumed to have no revenues from capacity markets or balancing markets. We assume that the Norwegian share of the annualised costs related to capital and operation are as estimated in the concession application of NorthConnect of €46 million and €5 million p.a. respectively. As illustrated in Figure 6.7, the net interconnector income of a 1 400 MW cable between NO5 and GB is positive for all years between 2026 and 2045. However, the range of the net interconnector income includes negative values in the initial years from 2026 to 2032, underlining the downside risk of low price differentials between NO5 and GB. The present value (PV) of the Norwegian share of the net interconnector income is €1,12 billion[4] for the period

[4]The PV of the net interconnector income is derived using a discount rate of 3,1 % (based on Bjørndal and Johnsen (2018)) over 20 years.

from 2026 to 2045.

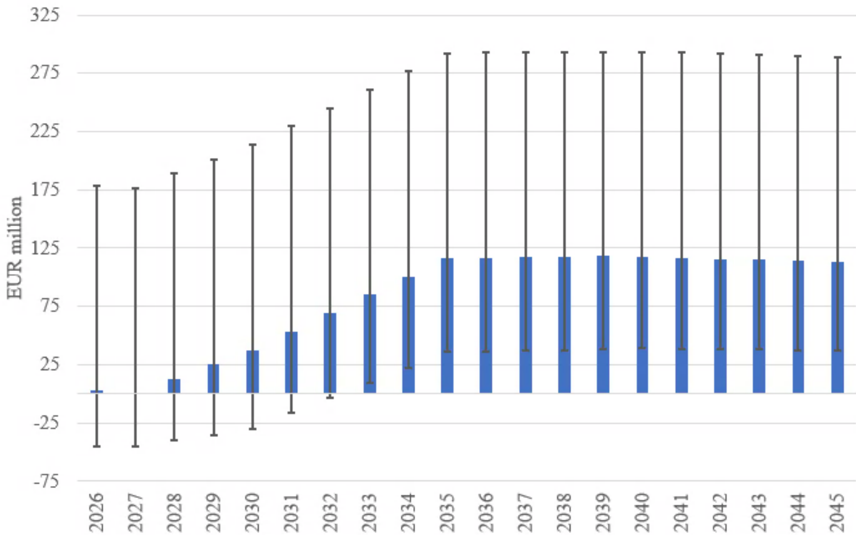

Figure 6.7 – The estimated net interconnector income in million 2018 EUR of a 1 400 MW cable between NO5 and Great Britain.

The interconnector flow is the flow of electricity in TWh through a cross-border interconnector. The estimated interconnector flow of a 1 400 MW cable will decline from 11,5 TWh in 2026 to 10,5 TWh in 2045, as illustrated in Appendix 9.24. The interconnector flow is declining due to an increasing share of hours in which the price differential is zero. From 2026 to 2045 the share of hours with a zero price differential increases from 0,4 % to 9,8 %. This thesis estimates that the interconnector flow is in the direction of GB in most hours, due to lower prices in NO5 than in GB. In 2030, the total interconnector flow of both the NSL and NorthConnect cables will be 21,5 TWh, of which 18,0 TWh will be in the direction of GB, as presented in Appendix 9.25.

6.3.1 *Analysis of the congestion rent subject to income regulation*

The retained congestion rent of a 1 400 MW cable between NO5 and GB will depend on the interconnector income regulation. If the Norwegian share of the interconnector is unregulated, the interconnector owner can retain all of the estimated congestion rent, as shown in Figure 6.8(a). Thus, not subject to an income regulation, the PV of the Norwegian share of the net interconnector income is €1,12 billion for the period from 2026 to 2045.

If an interconnector is subject to a revenue cap regulation with a one-year settlement period, where the cap is set to €150 million[5], the interconnector owner can retain a maximum annual congestion rent of €150 million for the Norwegian share of the cable. As shown in Figure 6.8(b), the estimated congestion rent exceeds the revenue cap in the years from 2034 to 2045 and the revenue cap will thus be triggered for these years. The error bars in Figure 6.8(b) illustrate the range of the estimated congestion rent. At the top of the error bars the revenue cap will be triggered each year from 2026 to 2045, whereas the revenue cap will not be triggered any year at the bottom of the error bars. The PV of the net interconnector income of a cable subject to a €150 million revenue cap is €1,00 billion. Thus, the revenue cap creates a loss to the interconnector owner of €0,12 billion, since the PV is smaller than the PV of the unregulated net interconnector income of €1,12 billion.

Figure 6.8(c) depicts the congestion rent of an interconnector subject to a cap and floor regulation with a one-year settlement period, where the revenue cap is set to €150 million and the floor is set to €90 million[6]. The revenue cap is triggered the eleven years from 2035 to 2045, which lowers the retained congestion rent relative to the unregulated congestion rent. The floor is triggered in the initial five years from 2026 to 2030, which increases the retained congestion rent compared to the unregulated congestion rent. The range of the estimated congestion rent, shown by the error bars in Figure 6.8(c), captures both the cap and floor in each year. The PV of the net interconnector income of a cable subject to a cap and floor regulation is €1,11 billion. Thus, the PV of a cable under a cap and floor regulation is smaller than the PV of an unregulated cable. Nevertheless, the floor increases the PV with €0,11 billion compared to the PV of a cable subject to a revenue cap of €1,00 billion.

Figure 6.8(d) depicts the congestion rent of an interconnector subject to a revenue cap regulation with a five-year settlement period. The revenue cap for the five-year settlement period is set to €750 million[7]. The revenue cap is triggered in the last two settlement periods from 2036-2040 and 2041-2045. The range of the estimated congestion rent in Figure 6.8(d) illustrates that at the top of the error bars the revenue cap is triggered each settlement period, whereas at the bottom of the error bars the revenue cap is not triggered in any settlement period. The PV of net interconnector income of a cable subject to a cap regulation with a five-year settlement period

[5]The €150 million revenue cap is set similar to the revenue cap used by Bjørndal and Johnsen (2018) for the NorthConnect cable and Pöyry (2014) for the NSL cable.

[6]The €90 million floor is set similar to the floor used by Pöyry (2014) for the NSL cable.

[7]The revenue cap is given by the annual revenue cap of €150 million $\times$ 5 years = €750 million.

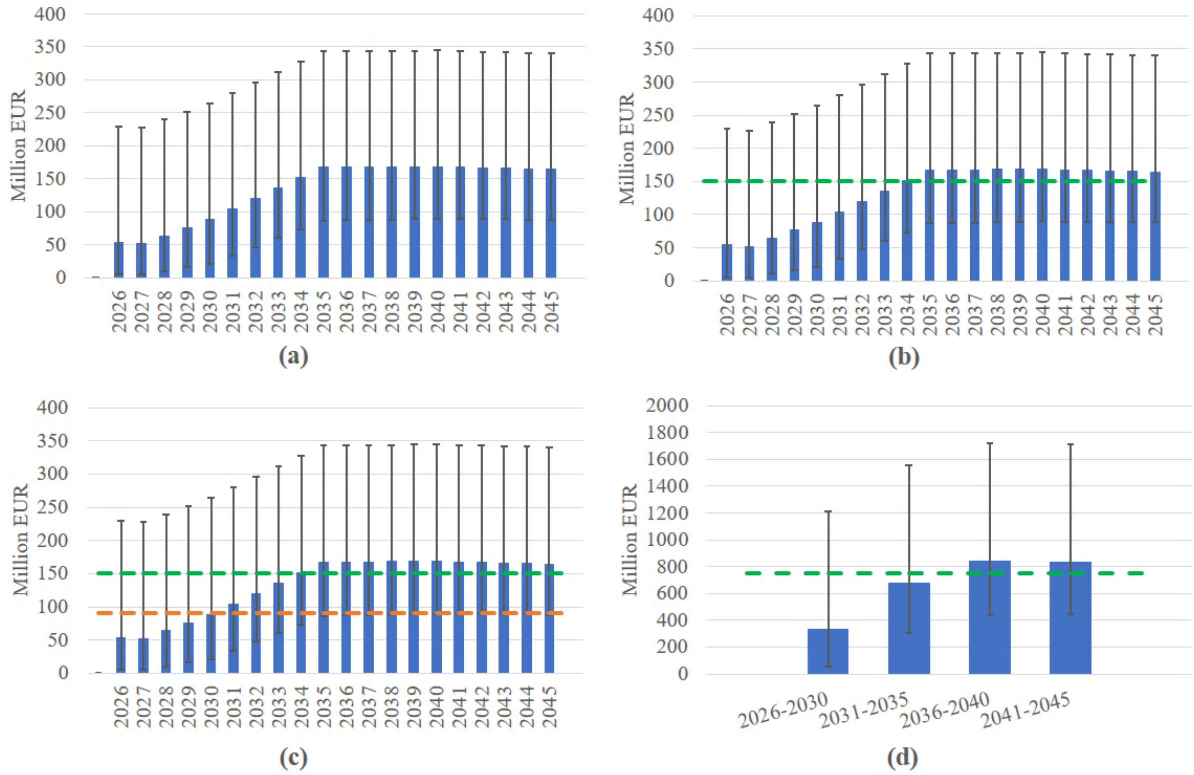

Figure 6.8 – **(a)** The Norwegian share of the congestion rent of a 1 400 MW cable between NO5 and GB for all years between 2026 and 2045 in million 2018 EUR, unregulated. **(b)** The Norwegian share of the congestion rent subject to a revenue cap of €150 million (green dotted line). **(c)** The Norwegian share of the congestion rent subject to a revenue cap of €150 million (green dotted line) and a floor of €90 million (orange dotted line). **(d)** The Norwegian share of the congestion rent subject to a revenue cap of €750 million (green dotted line) with a five-year settlement period.

is €1,02 billion. This is €0,2 billion higher than the PV of €1,00 billion of an interconnector subject to a revenue cap with a one-year settlement period. Thus, a five-year settlement period increases the PV of the net interconnector income subject to a revenue cap regulation.

6.3.2 *Comparisons of different estimates of the congestion rent*

Since a main risk of an interconnector is related to the price differential between the two power markets a cable connects, it is of interest to assess how the estimated congestion rent in this thesis differs from the congestion rent of four scenarios outlined in the concession application of NorthConnect from 2017. The congestion rent varies substantially between reports and scenarios, see Figure 6.9. This emphasises how differences in assumptions related to supply, demand and electricity mix affect electricity prices and how this in turn leads to substantially divergent congestion rents. The value of the congestion rent estimated in this thesis is most similar to the congestion rent of the climate scenario in the concession application, which underlines that the RES assumptions of THEMA are bullish compared to the industry average.

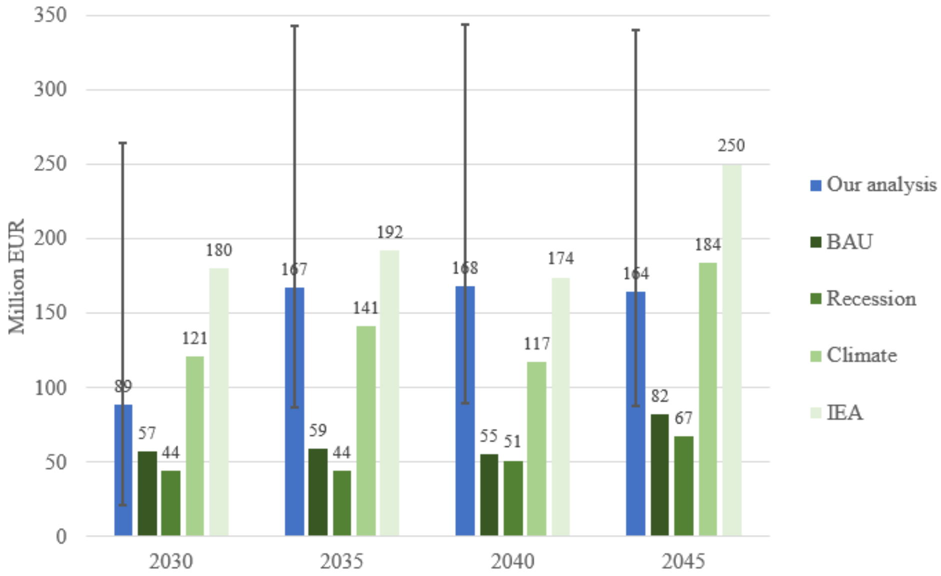

Figure 6.9 – The Norwegian share of the estimated congestion rent of a 1 400 MW cable between NO5 and GB for selected years between 2030 and 2045 from the analysis in million 2018 EUR, compared to the Norwegian share of the congestion rent provided in the NorthConnect concession application from 2017 in million 2016 EUR for the four scenarios business as usual (BAU), recession, climate and the IEA scenario (shown from left to right). A description of the four scenarios is given in Appendix 9.5

The concession application of NorthConnect (2017) states that the Norwegian share of the congestion rent will be €57 million in 2030 in the business as usual scenario. This is less than the €88,6 million estimated in this analysis. However, the estimated congestion rent in this analysis is based on the assumption that all the capacity of a 1 400 MW cable is dedicated to trade on the spot market, and no capacity contracts are made. Whereas the concession application includes revenues from the participation in the UK capacity market. If the Norwegian share of the capacity market revenues of €19 million are included, the total interconnector income of NorthConnect becomes €76 million, which is closer to the estimated congestion rent in this analysis. Note that the concession application of NorthConnect assumes that a 1 400 MW cable will commence operation in 2023, whereas the TheMA model providing the simulated future electricity prices for this thesis anticipates that the cable will not commence operation before 2026.

7. Discussion

First, this chapter presents the implications of integrated electricity markets on prices and social welfare in Norway and the UK. Thereafter, the uncertainties of the estimated congestion rent is discussed. Finally, the implications of ownership and income regulation on cross-border interconnectors are debated.

7.1. Implications of integrated electricity markets on prices and social welfare

The integration of electricity markets will impact electricity prices and the net social welfare in the connected regions. However, the impact will depend on the size and the characteristics of each power market, specifically whether it mainly exports or imports electricity.

7.1.1 *Impact of integration on electricity prices*

As a response to additional transmission capacity, a low-cost power market is expected to increase its electricity generation and export the commodity to connected high-cost power markets. Subsequently, the electricity price will increase according to the low-cost power market's merit order curve. Norway is characterised as a low-cost power market due to the large share of flexible hydroelectric power generation with a low marginal cost of capacity. Thus, additional interconnectors between Norway and high-cost power markets suggest higher Norwegian electricity prices. It is therefore plausible to expect that the interconnector NorthConnect will increase electricity prices in Norway, and potentially in other connected low-cost power markets. The possible ripple effect is due to the high level of integration of the Nord Pool area, which Norway is a part of. The expected price increase is supported by the concession application of NorthConnect from 2017, which quantifies the increase in the Norwegian electricity prices to 1,7 Norwegian øre/kWh in 2030.

Opposite, a high-cost power market is expected to increase its imports from low-cost power markets as a response to additional cross-border transmission capacity. Thus, the power market will leave some of its high-cost generation capacity unused and subsequently the electricity price will decrease. The UK is an example of a high-cost power market, which historically has been a net importer of electricity. It is anticipated that imports of electricity will continue to cover parts of the UK electricity demand. Further, it is expected that as coal generation is phased out, the relatively higher marginal cost of gas will determine the UK electricity price according to the merit order. In sum, this will consolidate the UK as a high-cost importing power market. Therefore, it can be argued that the UK electricity prices will decrease as the country becomes more integrated with neighbouring low-cost power markets.

However, the size of a power market will subdue the effect of additional cross-border interconnectors on the power market's electricity prices. Due to the large size of the UK power market, it is possible to argue that a 1 400 MW interconnector will not have a substantial effect on the UK electricity prices, since the cable will only constitute a negligible part of the total installed generation capacity. As of 2017, the UK had an installed generation capacity of 81 300 MW, thus a 1 400 MW interconnector would only have added approximately 1,7 % to the total capacity in that specific year. Consequently, one additional interconnector will most likely not impact the UK power market greatly. This is supported by the concession application of NorthConnect, which states that the interconnector will have a relatively smaller effect on electricity prices in the UK than in Norway, due to the size of the UK power market.

According to theory, additional transmission capacity should diminish the electricity price differential between a low-cost and a high-cost power market. This is in line with the studies by Spiecker et al. (2013) and Auverlot et al. (2014), who find that electricity prices converge as transmission capacity increases in Europe. Since the UK is regarded as a high-cost thermal power market and Norway as a hydro-dominated low-cost power market, it is expected that the price differential between the two countries will decrease after the interconnector NorthConnect commences operation.

The analysis in this thesis finds that the simulated electricity prices in the bidding zone NO5 and the market area Great Britain do not follow the expected movements in the years after the interconnectors NSL and NorthConnect commence operation. Only the UK electricity prices fall as expected to theory after the NSL cable commences operation in 2021. These findings suggest that the observed simulated electricity prices in the analysis will mainly be affected by other factors than additional cross-border interconnectors. This is supported by NVE (2017), who states that movements in electricity prices will primarily be caused by determinants other than additional cross-border transmission capacity.

7.1.2 *Impact of integration on social welfare*

Similar to electricity prices, the impact of additional cross-border transmission capacity on net social welfare depends on whether the power market is an exporter or an importer of electricity.

In an exporting power market, it is expected that additional cross-border transmission capacity will increase electricity prices, and thereby decrease the consumer surplus and increase the producer surplus. Norway, as a low-cost power market and a net exporter of electricity, is anticipated to experience an increase in the producer surplus at the expense of the consumer surplus after NorthConnect commences operation. This is in line with the concession application of NorthConnect from 2017, which states that the interconnector will reduce the Norwegian consumer surplus and increase the producer surplus.

Opposite, for an importing power market additional cross-border transmission capacity will lower the electricity prices, which in turn will increase the consumer surplus at the expense of the producer surplus. Consequently, it is to expect that additional transmission capacity from the UK, a high-cost importing power market, will increase the British consumer surplus and decrease the producer surplus. This is supported by the concession application of NorthConnect, which states that the interconnector will increase the British consumer surplus at the expense of the producer surplus. Thus, a welfare gain of one stakeholder group in one region will be accompanied by a welfare loss of that particular stakeholder group in a connected region.

The interconnector wealth of an existing cable may be affected by additional interconnectors. Increased cross-border transmission capacity is expected to reduce the price differential between the connected areas, negatively impacting the interconnector wealth. Further, additional interconnectors may impact the electricity prices of neighbouring power markets and in turn reduce the interconnector wealth of other cables. Therefore, it is possible to assume that the interconnector wealth will be subject to a cannibalism effect and thus be decreased. However, the literature on this topic is ambiguous. Spiecker et al. (2013) find a cannibalism effect, whereas Pöyry (2014) excludes such an effect. Nevertheless, as the NorthConnect interconnector is owned by a consortium of public power companies the potential interconnector wealth will in turn benefit the society.

In sum, the net social welfare of additional cross-border transmission capacity depends on the size of the changes in the consumer surplus, the producer surplus and the interconnector wealth. For a low-cost exporting power market as Norway, the net social welfare will be positive if the increase in the sum of producer surplus and interconnector wealth is greater than the decrease in consumer surplus. Whereas, a high-cost importing power market as the UK will experience a positive net social welfare if the increase in the sum of consumer surplus and interconnector wealth exceeds the decrease in producer surplus. If this is the case, an interconnector between the bidding zone NO5 and the market area Great Britain will contribute positively to the social welfare in both regions. In fact, it is expected that NorthConnect will increase the social welfare in Norway and the UK, as stated in the concession application from 2017.

7.2. Implications of uncertainties on the congestion rent

An estimation of the congestion rent of a 1 400 MW cross-border interconnector between the bidding zone NO5 and the market area Great Britain has been conducted in this thesis. The estimated congestion rent will vary between a minimum of €51,4 million and a maximum of €168,4 million between 2026 and 2045 for the Norwegian share of the cable. Thus, the congestion rent of a 1 400 MW cable is expected to be substantial. Even after subtracting annualised costs related to capital and operation, the net interconnector income is robust, except for the initial years.

The significant uncertainty around the future development of power markets and electricity prices in Norway and Northern Europe implies that the estimated congestion rent may be substantially different from the realised congestion rent. Specifically, there is an uncertainty related to the future electricity price differential between connected markets. A zero to small price differential constitutes a severe risk for the interconnector income, in which the congestion rent may be negligible. Whereas a large price differential will provide a substantial congestion rent and is therefore beneficial for the interconnector owner. In fact, the share of hours with a zero-price differential between the bidding zone NO5 and the market area Great Britain increases from 0,4 % in 2026 to 9,8 % in 2045. However, the price differential between NO5 and GB is expected to be substantial, with an average of 20,15 €/MWh over the period from 2019 to 2045.

By assessing the historical development of electricity prices in NO5 and Great Britain, it may be possible to illustrate the range of outcomes of the future price differential. Historically, the electricity prices in the bidding zone NO5 and the market area Great Britain have differed in terms of level and structure. During the period from 2011 to 2017, the average electricity price in Great Britain of 53,99 €/MWh was substantially higher than the average electricity price in NO5 of 30,43 €/MWh. One possible explanation for higher prices in Great Britain is the power market's large share of high-cost generation capacity compared to NO5. Historically, the electricity prices in Great Britain have exhibited a higher degree of volatility than prices in NO5. It is argued that the difference in volatility is explained by the structural difference between the two power markets. Our analysis confirms that thermal power markets like Great Britain exhibit short-term price volatility. Whereas, power markets with a large share of flexible hydroelectric generation like NO5 exhibit long-term price volatility over seasons.

It is possible to argue that the historical price differential between the bidding zone NO5 and the market area Great Britain has been substantial. The two power markets are not closely correlated in the period from 2011 to 2017. This is supported by an observed price differential higher than 13,83 €/MWh for 75 % of the hours in the sample period. In sum, this suggests that the electricity prices and the characteristics of the two power markets have historically been fundamentally different.

The potential range of the estimated congestion rent, constructed from the historically positively skewed distribution of the electricity price differential from 2011 to 2017, show that the estimated congestion rent is expected to vary greatly. Thus, the congestion rent may become insufficient to provide an adequate rate of return on the interconnector investment. In fact, the potential range of the net interconnector income includes negative values in the years from 2026 to 2032.

If the conditions affecting historical prices remain relevant for determining the future prices, it may be expected that the estimated congestion rent of an interconnector between the bidding zone NO5 and the market area Great Britain will vary substantially in the future. However, it can be argued that it is unlikely that the conditions of the past remain similar to those of the future. Specifically, uncertainties in future prices may be caused by alterations in the future electricity mix of power markets and additional interconnectors, among others.

New generation capacity and the decommissioning of existing generation capacity may alter the electricity mix in the future, which in turn will have implications for the price differential and thus the congestion rent. In the UK, the planned phase out of coal generation and the increase in electricity generation from RES, specifically wind power, is expected to affect the electricity prices. This is supported by the large movements observed in the simulated future electricity prices for the market area Great Britain in our analysis. Norway is expected to increase its power generation from wind. However, it has been stated that electricity generation from wind in connected regions are only moderately correlated. Nevertheless, it is possible to argue that a growing share of wind power in both Great Britain and Norway may make the two power markets more similar. Similar power markets may exhibit less different electricity prices in terms of level and structure, which in turn may reduce the price differential between the two markets. The estimated decline in the interconnector flow from 2026 to 2045 and the increased share of electricity exports from the market area Great Britain to the bidding zone NO5 suggest that the two power markets may in the future become more similar.

Finally, additional cross-border interconnectors may reduce the existing price differential between power markets. In other words, the congestion rent may be exposed to risks related to a cannibalism effect. The UK is integrated with the European electricity market through interconnectors to France, the Netherlands and Ireland. Currently, new interconnectors to the UK from Norway, Belgium and France are under construction. In addition to the NorthConnect cable, four interconnectors to the UK are being planned. In sum, these interconnectors will substantially increase the current UK interconnector capacity of 4 100 MW. Consequently, it is to expect that this solid increase in cross-border transmission capacity will reduce the electricity price in the high-cost power market UK. All else equal, a reduced price in the UK will lower the price differential between the bidding zone NO5 and the market area Great Britain, and thus negatively impact the congestion rent.

7.3. Implications of ownership on transmission capacity

The optimal level of cross-border transmission capacity built will depend on the type of ownership of an interconnector. A welfare-maximising TSO will choose to build transmission capacity such that it maximises the net social welfare as shown in equation (4.2), whereas a non-TSO investor will choose to maximise the private profits as shown in equation (4.5). The net social welfare of additional capacity includes benefits from improved security of supply and more efficient electricity generation. Thus, the investment decision of a welfare-maximising TSO will encompass the positive externalities caused by the additional transmission capacity. However, these positive externalities are not captured by a non-TSO investor and are therefore not included in the non-TSO investment decision. In the presence of positive externalities, the welfare-maximising TSO will therefore choose to build more transmission capacity relative to a non-TSO investor. Thus, it is possible to argue that a cross-border interconnector constructed by a non-TSO is likely to under-provide capacity relative to what is socially desirable on a national level. Further, it can be argued that a non-TSO investor will be more likely to refrain from building any transmission capacity at all than a welfare-maximising TSO, since a non-TSO investor only maximises the private profits.

Inadequate cross-border transmission capacity may cause an inefficient allocation of resources. Limited possibilities to trade electricity across regions may restrict a power market in terms of resource utilisation, security of supply and optimised power generation. These restrictions may create a cost for the society, a DWL. Thus, additional transmission capacity between power markets will reduce the DWL, since electricity may be allocated more efficiently across power markets. An objective of a welfare-maximising TSO is to minimise the DWL created by insufficient transmission capacity. However, since the investment cost of capacity is incorporated in the optimal capacity decision as shown in equation (4.4), a welfare-maximising TSO will not choose to build unlimited transmission capacity and some DWL will always remain. Furthermore, as shown in equation (4.6), neither the non-TSO investor will build unlimited transmission capacity. In fact, the non-TSO investor will choose to build less transmission capacity than the welfare-maximising TSO.

As argued, additional cross-border transmission capacity will lower the price differential between the connected markets and consequently affect the congestion rent of interconnectors negatively. Thus, there will be a trade-off between building additional capacity and receiving a lower congestion rent, regardless of ownership of an interconnector. This underlines that both welfare-maximising TSOs and non-TSOs may under-provide transmission capacity, since building additional capacity will occur at the expense of the interconnector income. Thus, it may not be ideal to leave capacity decisions to interconnector owners, regardless of ownership, since they have incentives to invest too little.

The income regulation of an interconnector may impact the optimal capacity built. However, the impact will depend on the ownership of the cable. The optimal capacity of a welfare-maximising TSO will not be effected by an income regulation. For instance, a revenue cap regulation will only alter the redistribution of the congestion rent between consumers and the interconnector owner, and not impact the size of the social welfare. Therefore, a welfare-maximising TSO, subject to a revenue cap, will disregard the distribution of social welfare and the optimal capacity remains constant in the presence of income regulation.

Opposite, the optimal capacity of a non-TSO will be affected by an income regulation. A revenue cap regulation is likely to reduce the capacity built by a non-TSO investor, since it will put a cap on the maximum retained revenues from the cable. Thus, a revenue cap will exacerbate the effect of the DWL since less transmission capacity will be built contributing to a more inefficient allocation of resources. However, the impact of a cap and floor regulation on capacity built by a non-TSO investor will depend on the level of the cap and the level of the floor. It is possible to argue that a too low cap will reduce the capacity built, whereas a sufficiently high floor will increase the capacity built. Thus, the effect of the cap and floor regulation on transmission capacity will pull in both directions. In sum, the income regulation of an interconnector may discourage development of transmission capacity.

Since inadequate cross-border transmission capacity may create costs to the society as a DWL, it is possible to argue that increased capacity is desired on a national and regional level. However, the arguments above suggest that both a TSO and a non-TSO investor may under-provide cross-border transmission capacity. The lack of investments in transmission capacity may be explained by the objective of the TSO and non-TSO investors to maximise social welfare and the congestion rent, respectively. For the non-TSO investor, it may also be explained by poor investment incentives in the income regulation of interconnectors. Therefore, if increased capacity is desired from non-TSO-owned interconnectors, the income regulation of interconnectors can be altered to facilitate increased non-TSO investments.

The interconnector NorthConnect will be developed by non-TSO investors, more specifically four large Nordic power companies. Thus, the capacity decision of NorthConnect has most likely been to maximise the private profits of the interconnector. In fact, it has been decided that NorthConnect will have a capacity of 1 400 MW, similar to other planned interconnector projects in Northern Europe. The estimated congestion rent and the net interconnector income in this thesis are positive in all years from 2026 to 2045. This is in line with the estimates provided by the concession application of NorthConnect from 2017. This points towards a positive profitability of the investment and it is thus possible to argue that the investment objective of the four power companies have be fulfilled.

Further, the NorthConnect project is expected to have a positive net social welfare of a minimum of €112 million annually as outlined in the concession application from 2017. Therefore, the investment objective of a welfare-maximising TSO may also be fulfilled. Thus, this suggests that a 1 400 MW cable between the bidding zone NO5 and the market area Great Britain should be developed regardless of ownership.

It is proposed that the Norwegian share of the interconnector NorthConnect will be subject to a revenue cap regulation, similar to that of the Norwegian network companies. The proposed regulatory regime has also most likely been a part of the capacity decision of the four power companies, since a revenue cap will put a maximum limit on the retained revenues of an interconnector as shown in our analysis. If the proposed revenue cap regulation has influenced the capacity decision, it is possible to argue that it may have reduced the chosen capacity of the interconnector. Moreover, the level of the revenue cap will further affect the capacity and investment decision of the NorthConnect project. It is argued that a revenue cap equal to the regulatory rate of return will imply that the interconnector owner will only face the downside risk of the investment. Thus, if this is the case, a too low revenue cap may discourage the investment decision. Since a revenue floor is not a legal option in the Norwegian income regulation, viable debt financing of the interconnector is most likely not an option.

7.4. Implications of income regulation on cross-border interconnectors

If investments in cross-border interconnector projects by non-TSO investors, such as NorthConnect, are desired, it is of interest to explore options of how to accommodate such investments through the income regulation of interconnectors. The design of the interconnector income regulation will most likely depend on characteristics of a power market. Relevant characteristics may include whether the power market is an exporter or importer of electricity, and whether additional transmission capacity is desired.

First, the income regulation may depend on whether a power market exports or imports electricity, since the benefits of an interconnector will be distributed differently in the two situations. The national regulatory authorities in an exporting country will design the regulation to compensate the consumers for increased prices caused by additional cross-border transmission capacity. Norway's position as a predominantly exporting country and the estimated interconnector flow from NO5 to Great Britain suggest that the Norwegian income regulation of interconnectors will most likely incorporate a compensation scheme for the consumer. This is in line with the current revenue cap regulation of the Norwegian network companies, where extraordinary revenues are redistributed to the consumers as lower network tariffs.

Opposite, the national regulatory authorities of an importing country have less incentive to incorporate schemes to compensate consumers, since additional transmission capacity is expected to lower electricity prices and benefit the consumers. Since the consumers in an importing country gain from increased cross-border transmission capacity, it is possible to argue that the consumers may even cover parts of the costs related to developing interconnectors. Such a cost scheme is currently practised in the UK through the cap and floor regulation. The UK have historically been a net importer of electricity and is expected to continue to depend on cross-border transmission capacity as indicated by the direction of the estimated interconnector flow. The UK consumers will most likely gain from additional cross-border interconnectors and can in principle cover parts of the interconnector costs. However, the UK cap and floor regulation also incorporates a compensating scheme for consumers, as revenues above the cap are redistributed to the consumers as lower network tariffs.

Second, the income regulation may depend on whether additional cross-border transmission capacity is needed in a power market. This is typically the case if authorities wish to secure energy supply. However, the objective of security of supply may not only be restricted to countries relying on imports, but may also be the objective of exporting countries which in periods experience low electricity generation. Norway is an example of the latter, where interconnectors will extend the import possibilities in dry years when hydro reservoirs are low.

Based on the discussion above, it is possible to argue that the income regulation of cross-border interconnectors constitutes an important part of the decision to invest in and build interconnectors. If national regulatory authorities wish to increase cross-border transmission capacity, the authorities can facilitate investments in capacity through a favourable income regulation for investors, among others. There are several possibilities for the income regulation to be modified to encourage investment in cross-border interconnectors.

One possibility is to set the revenue cap high enough to provide the interconnector investment with a sufficient rate of return to attract investors. As shown in the analysis, the introduction of a revenue cap of €150 million lowers the PV of the net interconnector income from €1,12 billion to €1,00 billion. Thus, a higher revenue cap will increase the retained congestion rent and in turn the net interconnector income. The rate of return should not only account for the high-risk exposure of a cross-border interconnector, but also be high enough to compete against similar energy infrastructure projects, such as wind parks, to attract investors.

However, a higher revenue cap will lower the redistribution to the consumers, who will receive less reimbursement in form of reduced network tariffs. Consequently, a higher revenue cap may create political opposition, especially from consumers in exporting countries who already face higher national electricity prices due to additional cross-border interconnectors. Such opposition has been witnessed in Norway from the Federation of Norwegian Industries when NorthConnect proposed a higher revenue cap for the interconnector than implied by the regulatory rate of return for Norwegian network companies set by NVE. Thus, a regulatory authority in an exporting country must, when setting a high revenue cap, weigh the benefits of additional transmission capacity against the lower redistribution to and possible opposition from the consumers.

A second possibility for the authorities is to extend the time interval for the settlement period in the income regulation. An interconnector subject to a revenue cap regulation with a yearly settlement period will each year redistribute the extraordinary revenues to the consumers. If an interconnector faces years with low income, it may be the case that the average annual revenues of the interconnector over its entire lifetime do not exceed the revenue cap. Consequently, a yearly settlement period will not reflect the average annual extraordinary revenues over the interconnector's lifetime. If the extraordinary revenues are settled every five years as shown in the analysis, years of lower congestion rent is compensated by years of higher congestion rent. The introduction of a five-year settlement period increases the PV of the net interconnector income from €1,00 billion to €1,02 billion. Thus, an extended settlement period will lower the asymmetry in the revenue cap regulatory regime, since years of low revenues will be accounted for and contribute to reduce the risk of the uncertainty in the future electricity price differential. The higher share of retained revenues by the interconnector owner may in turn encourage increased investment in transmission capacity. A five-year settlement period is custom in the UK, where the income regulation is designed to incentivise investment in interconnectors.

A third possibility to encourage increased cross-border transmission capacity is to incorporate a floor as a risk relief in the income regulation. By incorporating a floor of €90 million in the revenue cap regulation as shown in the analysis, the PV of the net interconnector income increases from €1,00 billion to €1,11 billion. Thus, a floor may decrease the risk exposure of the interconnector owner related to the price differential between power markets and possibly encourage investment in transmission capacity. To secure a sufficient risk relief, the level of the floor should cover the cost of debt as if the interconnector was fully funded by debt. The British cap and floor regulatory regime includes a risk relief, in which consumers cover parts of the potential losses of an interconnector.

However, from 2011 to 2017 high extreme price differentials have been observed more frequently than low extreme price differentials between the bidding zone NO5 and the market area Great Britain, as indicated by the kurtosis and positive skewness. If the future electricity prices will bear a resemblance to this historical price distribution, a revenue cap will be triggered more often than a floor. In fact, the analysis of this thesis shows that in the period from 2026 to 2045 a floor of €90 million is only triggered for five years, whereas a cap of €150 million is triggered for eleven years. This suggest that a sufficiently high revenue cap may have a higher importance for the investment decisions of a non-TSO interconnector owner than an adequate level of the floor. Therefore, it can be argued that national authorities should prioritise a sufficiently high revenue cap instead of a floor when encouraging cross-border transmission capacity.

A fourth possibility for the national regulatory authorities is to modify the regulation of the capacity markets. An interconnector owner can secure a guaranteed income by selling capacity contracts to generators and traders, regardless of future price developments. Thus, an interconnector owner may reduce its exposure to risk related to the price differential by increasing the share of income derived from capacity markets. This may constitute an indirect risk relief due to the complementary dynamics of the capacity markets and the spot markets, from which the congestion rent is derived. If the current regulation excludes or limits the participation in capacity markets, the interconnector owners are thus deprived from the possibility to be guaranteed a secure income. This suggests that if national authorities wish to encourage investment in cross-border transmission capacity, the authorities should allow access to capacity markets and potentially increase the allowed share of transmission capacity reserved for capacity contracts.

On a European level, the EU has set an ambitious target to increase the cross-border transmission capacity in Europe. As of 2017, twelve Member States have not reached the target of 15 % of installed interconnector capacity. A possible explanation for the relatively low level of installed interconnector capacity may be that national regulation only reflects the national benefit of transmission capacity, neglecting the overall benefit to Europe. Thus, it is possible to argue that national TSOs may not have incentives to invest in sufficient transmission capacity. This suggests that interconnector investment by non-TSO investors will play an important role to achieve the EU target and thus should be encouraged.

In an attempt to encourage increased investments in cross-border transmission capacity, the European Commission has proposed that the extraordinary revenues of an interconnector should be earmarked new investments in interconnectors. If accepted, this will replace the current practice of redistributing the extraordinary revenues to the consumers as reduced network tariffs. The proposed scheme may potentially increase the transmission capacity in Europe, since more funds will be designated to interconnector investments. However, this may lead to the consumers carrying a disproportionate large share of the investment cost of the interconnectors, as the consumers will no longer receive reductions in their network tariffs. This is especially applicable for exporting electricity markets, where consumers already face higher national electricity prices due to cross-border interconnectors.

In sum, there are several possibilities for a regulatory authority to encourage investments in cross-border transmission capacity through the income regulation of interconnectors. However, the income regulation may leave some stakeholders better off at the expense of others. Thus, all implications must be assessed before implementing an income regulation of an interconnector.

It is important to note that predicting electricity prices is a difficult task, since electricity prices are influenced by various factors which are challenging to determine. These factors include supply, demand, electricity mix and weather, i.e. temperature and precipitation. Therefore, the simulated prices will be heavily influenced by the assumptions of these factors, as shown in the analysis. Consequently, the future simulated electricity prices used in this thesis will not be perfectly accurate, regardless of the advanced functions of the TheMA model. Due to the uncertainties regarding future electricity prices, the estimated congestion rent will most probably differ greatly from the realised congestion rent.

This thesis applies a backward-looking technique to illustrate the potential range of the future electricity price differential between NO5 and Great Britain. A weakness of using a backward-looking technique is that it does not reflect current market conditions (Lidderdale and Ryan, 2009) or capture future market expectation of price behaviour (Wengler, 2001). Consequently, this may make the results inferior to the results of a forward-looking technique.

Further, the level of the revenue cap and the floor used in the analysis is set arbitrarily based on the studies by Pöyry (2014) of the NSL cable and by Bjørndal and Johnsen (2018) of the NorthConnect cable. Thus, the revenue cap of €150 million and the floor of €90 million are not based on an assessment in this thesis of the optimal revenue cap and floor for NorthConnect. The cap and floor levels are set to illustrate how retained congestion rent differs between regulatory regimes. The estimated retained congestion rent will therefore not reflect the realised congestion rent retained by the interconnector owners.

8. Conclusions

The European electricity market is gradually becoming more integrated due to increased cross-border transmission capacity. Integrated electricity markets are expected to improve social welfare through benefits from security of supply, better overall resource utilisation and more efficient electricity generation. Thus, inadequate cross-border transmission capacity causes an inefficient allocation of resources at a regional level.

The integration of electricity markets will impact electricity prices and the social welfare in the connected regions. The impact will depend on the size and the characteristics of the respective power markets. In response to a cross-border interconnector between a low-cost power market as Norway and a high-cost power market as the UK, Norwegian electricity prices is expected to increase whereas UK electricity prices is expected to decrease. However, due to the size of the UK power market, electricity prices in the UK will be relatively less impacted. If the transmission capacity of a new interconnector between two power markets is large enough to impact prices in the respective markets, it will alter the size and the distribution of the social welfare. As outlined in the concession application of NorthConnect, the net social welfare in both the UK and Norway are expected to increase after NorthConnect commences operation. However, the distribution of the net social welfare will differ between the two power markets. In Norway, the producers will gain at the expense of the consumers due to higher Norwegian electricity prices. Opposite, the decrease in the UK electricity prices will be beneficial to the consumers at the expense of the producers. Thus, a welfare gain of one stakeholder group in one region is accompanied by a welfare loss of that particular group in the connected region.

The annual congestion rent of the Norwegian share of a 1 400 MW interconnector between the bidding zone NO5 and the market area Great Britain is in this thesis estimated to vary between a minimum of €51,4 million and a maximum of €168,4 million in the period from 2026 to 2045. Further, the estimated net interconnector income is positive in all years, which suggests that a non-TSO-investor has incentives to build the cable. The concession application of NorthConnect from 2017 estimates a net social welfare of minimum €112 million annually. Therefore, the investment objective of a welfare-maximising TSO is also fulfilled. Thus, it is possible to conclude that a 1 400 MW cable should be developed regardless of ownership.

The analysis of the historical development of electricity prices in NO5 and Great Britain discloses that prices have varied substantially from 2011 to 2017. By including a potential range of the estimated congestion rent based on the historical positively skewed distribution of price differentials, the estimated congestion rent is expected to vary from the baseline in the future. Therefore, it is possible to argue that an uncertainty related to the estimated congestion rent originates from the price differential between the two power markets. Moreover, alterations in the future electricity mix of power markets and additional cross-border transmission capacity have been identified as possible sources of uncertainty regarding the future price differential.

Cross-border interconnectors are subject to regulation. National regulatory authorities design the income regulation of interconnectors to correct for the disproportionate distribution of the social welfare caused by the interconnectors. The income regulation in a low-cost exporting power market tends to include compensating schemes for the consumers who face higher electricity prices due to increased cross-border transmission capacity. Whereas the national authorities in a high-cost importing power market have less incentives to implement such compensating schemes, since the consumers benefit from increased cross-border transmission capacity.

The proposed income regulation of a non-TSO-owned interconnector in Norway will only include a revenue cap since a floor is not a legal option. A revenue cap will limit the maximum retained revenues of an interconnector owner. If the revenue cap is set too low, there is a possible risk that the retained revenues do not cover the costs related to the investment. Thus, the interconnector owner may receive an insufficient rate of return on the interconnector project. Consequently, potential investors may abstain from investing in cross-border transmission capacity and rather invest in other energy infrastructure projects with a higher expected rate of return.

If national regulatory authorities wish to encourage non-TSO investments in cross-border transmission capacity, the income regulation must account for the uncertainties related to the future price differential. A solution will be to implement a favourable income regulation of interconnectors for the owners. This thesis has identified four possible income regulations that facilitate non-TSO investments in interconnectors. One possibility is to set the revenue cap sufficiently high for interconnector owners to obtain an acceptable rate of return on their investment, since a revenue cap reduces the retained congestion rent compared to an unregulated congestion rent. This is proposed by NorthConnect, who argues that the Norwegian revenue cap of the interconnector must be based on a rate of return higher than 8 % to compensate for the lack of risk relief from a floor on the Norwegian share of the cable.

A second possibility to incentivise investment in transmission capacity is to extend the settlement period of the redistribution of extraordinary revenues. A five-year settlement period will compensate years of lower congestion rent with years of higher congestion rent and increase the retained congestion rent. Thus, an extended settlement period will limit the consequences of the uncertainty regarding the future electricity price differential for the interconnector owner. A five-year settlement period is custom in the UK, where the income regulation is designed to incentivise investment in interconnectors.

A third possibility is to incorporate a floor in the income regulation as a risk relief, similar to the British cap and floor regulation. By incorporating a floor, the retained congestion rent increases. Thus, a floor will limit the downside risk of an insufficient congestion rent, since the consumers will cover parts of the losses. Fourth, the regulatory authorities can allow for participation on the capacity market. In sum, it can be argued that the four possible income regulations identified in this thesis will separately and in combination facilitate construction of additional cross-border transmission capacity.

However, the proposed income regulations will benefit the interconnector owners at the expense of the consumers. The effect of the income regulation on consumers is important to incorporate when deciding on a regulatory regime, since the consumers constitute a significant part of the society. Consumers of electricity include energy-intensive industries which collectively can exert political power through organisations like the Federation of Norwegian Industries. Therefore, it is important to take into account their losses. This is especially relevant in exporting power market as Norway, since consumers already face higher electricity prices due to increased transmission capacity. While an assessment of how consumers are affected by the proposed income regulations is not addressed in this thesis, it is a topic for future research.

The uncertainty in future electricity prices constitutes a substantial risk for interconnector owners, since the retained revenues may not cover the costs of the investment. In fact, the potential range of the estimated net interconnector income includes negative values from 2026 to 2032. Being able to predict the future revenues more precisely will thus be of great value, especially for large investment projects like cross-border interconnectors. This thesis has identified that alterations in the future electricity mix of power markets and additional cross-border transmission capacity may affect future prices. However, it is out of the scope of this thesis to estimate the impact of the price determinants and may therefore be a topic for future research.

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9. Appendix

9.1. Norway's historical electricity generation by source

Norway's electricity generation in TWh				
	Hydro	Thermal	Wind	Total
2011	121,6	4,8	1,3	127,6
2012	142,8	3,4	1,5	147,7
2013	128,7	3,4	1,9	134,0
2014	136,2	3,6	2,2	142,0
2015	138,5	3,5	2,5	144,5
2016	143,4	3,5	2,1	149,0
2017	143,1	3,4	2,9	149,4

Norway's electricity generation in %				
	Hydro	Thermal	Wind	Total
2011	95,2 %	3,8 %	1,0 %	100 %
2012	96,7 %	2,3 %	1,1 %	100 %
2013	96,1 %	2,5 %	1,4 %	100 %
2014	95,9 %	2,5 %	1,6 %	100 %
2015	95,8 %	2,5 %	1,7 %	100 %
2016	96,3 %	2,3 %	1,4 %	100 %
2017	95,8 %	2,3 %	1,9 %	100 %

Table 9.1 – Historical electricity generation in Norway by source in TWh and as a percentage share of total electricity generation (Statistics Norway, 2018b).

9.2. Great Britain's historical electricity generation by source

Great Britain's electricity generation in TWh										
	Nuclear	Hydro	RES*	Wind**	Coal	Oil	Gas	Other RES†	Other	Total
2011	69,0	5,7	15,9	12,8	108,6	3,1	146,5	13,0	2,8	364,5
2012	70,4	5,3	21,2	17,2	143,1	2,6	100,2	14,7	3,4	360,9
2013	70,6	4,7	30,4	24,0	130,3	2,1	95,8	18,1	3,4	355,4
2014	63,7	5,9	36,0	26,8	100,2	1,9	100,9	22,6	3,9	335,2
2015	70,3	6,3	47,8	34,7	75,9	2,0	99,9	29,3	4,6	336,1
2016	71,7	5,4	47,7	32,7	30,7	1,9	143,4	30,1	5,6	336,3
2017	70,3	5,9	61,5	44,0	22,5	1,6	136,7	31,9	5,2	335,8

Great Britain's electricity generation in %										
	Nuclear	Hydro	RES*	Wind**	Coal	Oil	Gas	Other RES†	Other	Total
2011	18,9 %	1,6 %	4,4 %	3,5 %	29,8 %	0,9 %	40,2 %	3,6 %	0,8 %	100 %
2012	19,5 %	1,5 %	5,9 %	4,8 %	39,7 %	0,7 %	27,8 %	4,1 %	0,9 %	100 %
2013	19,9 %	1,3 %	8,6 %	6,8 %	26,7 %	0,6 %	27,0 %	5,1 %	1,0 %	100 %
2014	19,0 %	1,8 %	10,7 %	8,0 %	29,9 %	0,6 %	30,1 %	6,8 %	1,2 %	100 %
2015	20,9 %	1,9 %	14,2 %	10,3 %	22,6 %	0,6 %	29,7 %	8,7 %	1,4 %	100 %
2016	21,3 %	1,6 %	14,2 %	9,7 %	9,1 %	0,6 %	43,6 %	8,9 %	1,7 %	100 %
2017	21,0 %	1,8 %	18,3 %	13,1 %	6,7 %	0,5 %	40,7 %	9,5 %	1,6 %	100 %

Table 9.2 – Historical electricity generation in Great Britain by source in TWh and as a percentage share of total electricity generation. *RES include wind, wave and solar. **Wind is included in RES. †Other RES include biofuels. (BEIS (2018), BEIS (2017), BEIS (2016)).

9.3. Existing cross-border interconnectors in Northern Europe

Countries	Name of cable(s)	Year	Capacity
Norway-Sweden	9 cables		3200-3600 MW
Norway-Denmark	Skagerak 1-2	1976-77	510 MW
Norway-Denmark	Skagerak 3	1993	530 MW
Norway-Denmark	Skagerak 4	2014	700 MW
Norway-Netherlands	NorNed	2008	700 MW
Norway-Finland	Varangerbotn-Ivalo		70-120 MW
Norway-Russia	Kirkenes-Borisoglebskaya		50 MW
Sweden-Finland	Fennoskan 1	1989	500 MW
Sweden-Finland	Fennoskan 2	2011	800 MW
Sweden-Germany	Baltic Link	1994	600 MW
Sweden-Poland	SwePol	2000	600 MW
Sweden-Lithuania	NordBalt HVDC	2015	700 MW
Denmark-Sweden	Kontiskan 1	1965	250 MW
Denmark-Sweden	Kontiskan 2	1988	300 MW
Denmark-Germany	Kontek	1995	600 MW
UK-France	HVDC Cross-Channel	1986	2000 MW
UK-Netherlands	BritNed	2011	1000 MW
UK-Ireland	East West Interconnector	2012	500 MW

Table 9.3 – Existing cross-border interconnectors in Northern Europe (ENTSO-E, 2018, Ardelean and Minnebo, 2015).

9.4. Future cross-border interconnectors in Northern Europe

Countries	Name of cable(s)	Year	Status	Capacity
Norway-Germany	NordLink	2020	Under construction	1400 MW
Norway-UK	North Sea Link (NSL)	2021	Under construction	1400 MW
Norway-UK	NorthConnect	2023	Planned	1400 MW
UK-Belgium	Nemo Link	2019	Under construction	1000 MW
UK-France	ElecLink	2019	Under construction	1000 MW
UK-France	IFA 2	2020	Under construction	1000 MW
UK-France	FAB	2022	Under construction	1400 MW
UK-Iceland	Ice Link	2022	Planned	1200 MW
UK-Germany	NeuConnect	2022	Planned	1400 MW
UK-Denmark	Viking Link	2023	Planned	1400 MW
UK-Netherlands	New Great Britain	2030	Planned	1000 MW
Denmark-Germany	Krieger's Flak	2018	Under construction	400 MW
Denmark-Netherlands	CobraCable	2019	Under construction	700 MW
Sweden-Germany	Hansa Power Bridge 1	2026	Planned	700 MW
Sweden-Germany	Hansa Power Bridge 2	2030	Planned	700 MW

Table 9.4 – Future cross-border interconnectors in Northern Europe (ENTSO-E, 2018b, NorthConnect, 2017). The projects with the status planned include the categories in permitting, planned and under consideration (ENTSO-E, 2018a).

9.5. Congestion rent of the Norwegian share of NorthConnect

The concession application of NorthConnect (2017) outlines estimations for the congestion rent in four scenarios. The business as usual scenario is based on the continuance of the current practice. The recession scenario takes into account factors that will intensify the downside for interconnectors such as low demand, price levels and price spreads between Norway and the UK. In the recession scenario the UK carbon price support is abolished. The climate scenario incorporates a high focus on climate in which RES generation increases strongly and carbon prices remain high. The IEA new policy scenario is included in the concession application as a sensitivity analysis. The IEA scenario is based on the climate scenario but takes into account fuel and carbon prices from the IEA New Policy scenario of November 2015.

	Business as usual	Recession	Climate	IEA new policy
2023	88	46	82	102
2025	90	46	89	111
2030	57	44	121	180
2035	59	44	141	192
2040	55	51	117	174
2045	82	67	184	250

Table 9.5 – The Norwegian share of the congestion rent of NorthConnect in 2016 million EUR for the four scenarios: business as usual (BAU), recession, climate and IEA new policy (NorthConnect, 2017).

9.6. Income regulation of Norwegian network companies

The income regulation of Norwegian network companies is outlined in the "Forskrift om kontroll av nettvirksomhet" (1999, § 7-2), which states that the income of an interconnector must cover network costs and provide a reasonable rate of return on the investment over time. The income regulation of Norwegian network companies is controlled by NVE.

NVE determines an annual allowed revenue for each network company based on a revenue cap and various costs related to R&D and the costs of energy not supplied (CENS) as illustrated in Figure 9.1. The annual revenue cap is company specific and based partly on the network companies own cost base related to investment and operation (40%) and partly on efficiency comparison (60%), with a two-year lag in the cost data (Forskrift om kontroll av nettvirksomhet, 1999, § 8-6). A company with efficiency at the same level as the industry average has a cost base equal to the cost norm, and will have all of its costs covered by the revenue cap. Furthermore, the cost base is calculated using a regulatory rate of return, known as the NVE rate. Consequently, a company with costs equal to the cost norm will have a return equal to the NVE rate.

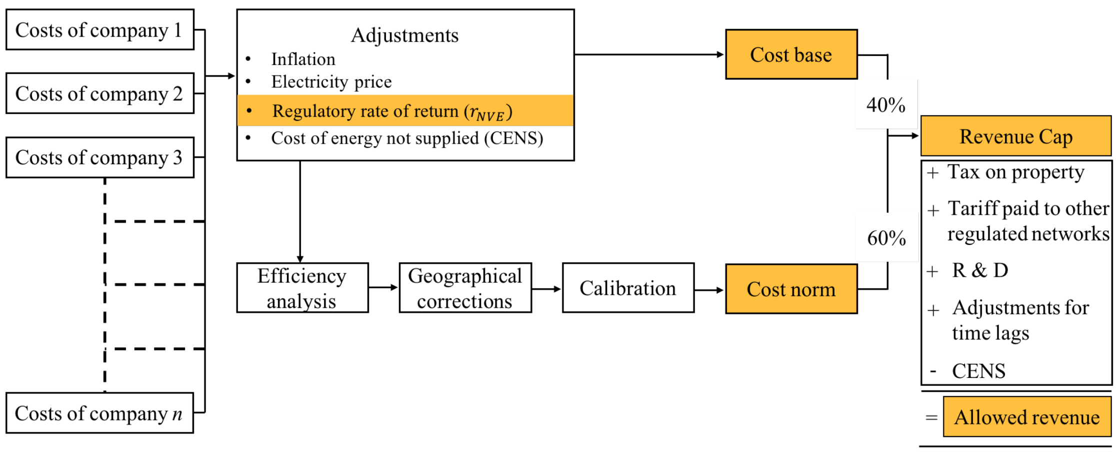

Figure 9.1 – The income regulation of Norwegian network companies, depicted by Burheim and Dahl (2016), translated by the authors.

The NVE rate is calculated using a weighted average cost of capital (WACC) model (Forskrift om kontroll av nettvirksomhet, 1999, § 8-3). The formula of the NVE rate, r_{NVE}, is given by equation (9.1). A description of the parameters are given in Table 9.6.

$$r_{\mathrm{NVE}} = (1 - G) \times \frac{Rf + \text{inflation} + (\beta e \times MP)}{1 - t} + G \times (\text{Swap} + P_d) \tag{9.1}$$

	Definition	Classification
G	Gearing, i.e. debt share of total capacity	Fixed
Rf	Real risk-free rate of equity	Fixed
Infl	Moving average of inflation of last year, current year and next two years	Variable
βe	Equity beta, estimated from an asset beta	Fixed
MP	Market premium	Fixed
Swap	Nominal rate of debt given by annual average of 5-years swap rate	Variable
KP	Debt premium given by the annual average credit spread of 5-year bonds for the power sector	Variable
t	Tax rate	Fixed

Table 9.6 – The regulatory rate of return parameters (Forskrift om kontroll av nettvirksomhet, 1999, § 8-6).

The NVE rate is set annually and has varied between 4,20 % and 7,83 % over the last ten years (NVE, 2018b). The NVE rate for 2018 was announced in October 2018 to be 6,05 %, but revisions may occur. The NVE rate represents the rate of return that an average efficient network company will retain through the revenue cap and allowed revenue. The flexible NVE rate allows the revenue cap to be adjusted based on actual costs and income from the previous periods (Meeus and Saguan, 2011). This mechanism provides opportunities for cost efficiency to the network company as lower costs will result in higher retained earnings (THEMA, 2017, Meeus and Saguan, 2011). However, if the NVE rate is lower than the cost of capital, the network company faces an underlying risk of the investment being unprofitable (THEMA, 2017).

9.7. Monthly conversion rates from GBP to EUR

	2011	2012	2013	2014
January	1,18	1,20	1,20	1,21
February	1,18	1,20	1,16	1,21
March	1,15	1,20	1,16	
April	1,13	1,21	1,18	
May	1,14	1,24	1,18	
June	1,13	1,24	1,17	
July	1,13	1,27	1,16	
August	1,14	1,27	1,16	
September	1,15	1,25	1,19	
October	1,15	1,24	1,18	
November	1,17	1,24	1,19	
December	1,18	1,23	1,20	

Table 9.7 – Monthly conversion rates from British pound sterling (GBP) to euro (EUR) in the period 2011 to 2014 (OFX, 2018).

9.8. Future supply and demand balance for the Nordics

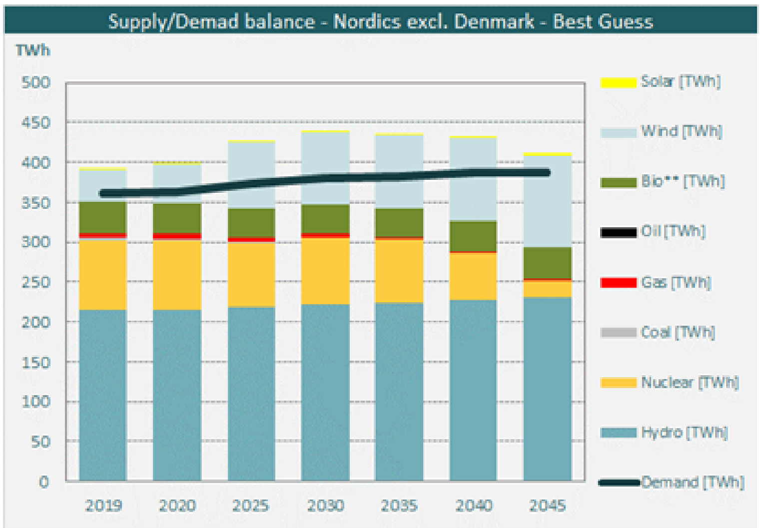

Figure 9.2 – The future electricity supply and demand balance for Norway, Sweden and Finland. Provided by THEMA Consulting Group.

9.9. Future supply and demand balance for Great Britain

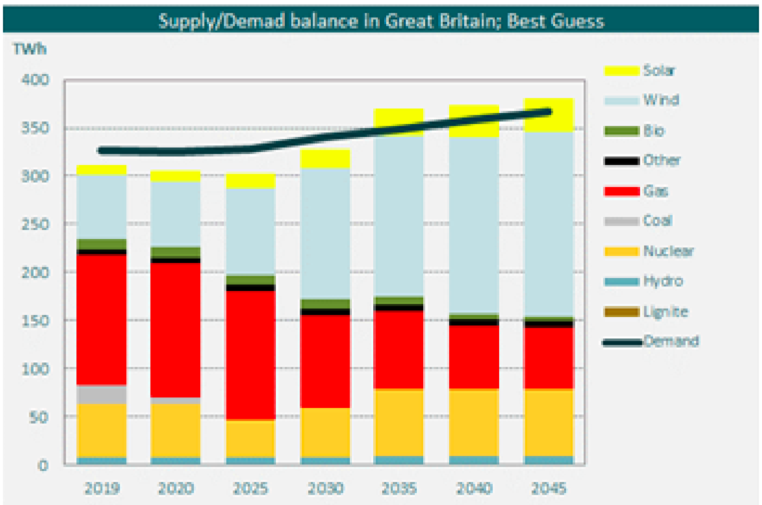

Figure 9.3 – The future electricity supply and demand balance for Great Britain. Provided by THEMA Consulting Group.

9.10. The Jarque-Bera test for normality

The Jarque-Bera test for normality in the electricity price itself of the bidding zone NO5, the market area Great Britain and the price differential between NO5 and Great Britain has been executed for the sample period as a whole. The Jarque-Bera test is preferred due to the large number of observations in the data set. The Jarque-Bera formula is presented in equation (9.2), where, S is the skewness, K is the kurtosis and N is the number of observations in the data set.

$$JB = N \times (\frac{S^2}{6} + \frac{(K-3)^2}{24}) \tag{9.2}$$

The null hypothesis is that the data is normally distributed. Thus, under the null hypothesis, the Jarque-Bera statistic follow a chi-squared normal distribution. The alternative hypothesis is that the data is not normally distributed. We can reject the null hypothesis at a 1 % significance level for NO5, Great Britain and the price differential.

	p_t^{NO5}	p_t^{GB}	$\lvert z_t \rvert$
N	61 365	61 365	61 365
S	1,43	16,22	15,38
K	9,04	695,49	656,58
JB test statistic	585 588***	7 359 470 582***	6 555 692 180***

Table 9.8 – The Jarque-Bera test for normality of the electricity price itself p_t in the bidding zone NO5 p_t^{NO5}, the market area Great Britain p_t^{GB} and the price differential $|z_t|$. The critical value for a chi-squared distribution with 2 degrees of freedom is 9,210 for a 1 % significance level***.

The Jarque-Bera test have been criticised as it tends to reject the null hypothesis of normality often and does not provide information on how the data are violating normality.

9.11. Autocorrelation

The autocorrelation coefficient (AC), the partial autocorrelation coefficient (PAC) and the Q-statistic for the bidding zone NO5 and the market area Great Britain for the electricity price itself and the first difference of the electricity price is presented with twenty lags.

For bidding zone NO5, the electricity price itself is highly correlated with all its past values, as shown in Figure 9.4. This observed persistence in prices is due to the relatively short time interval of hourly prices. Therefore, the first difference of electricity prices given in Figure 9.5 will provide information on how many lags to include. As illustrated in Figure 9.5 the sixth lag has an effect on electricity prices, which underlines that six lags should be included to account for the autocorrelation.

For the market area Great Britain, the correlation of the electricity price itself is presented in Figure 9.6. Contrary to the bidding zone NO5, the electricity price itself is not highly correlated will all its past values. This is due to a higher intraday volatility in Great Britain than in NO5. Therefore, it is sufficient use the electricity price itself when deciding how many lags that must be included to account for autocorrelation. As indicated in Figure 9.6, the third lag has an effect on prices and thus three lags should be included.

LAG	AC	PAC	Q	Prob>Q	-1 0 1 [Autocorrelation]	-1 0 1 [Partial Autocor]
1	0.9842	0.9842	59446	0.0000		
2	0.9613	-0.2372	1.2e+05	0.0000		
3	0.9428	0.1917	1.7e+05	0.0000		
4	0.9280	0.0321	2.2e+05	0.0000		
5	0.9173	0.1195	2.8e+05	0.0000		
6	0.9099	0.0738	3.3e+05	0.0000		
7	0.9065	0.1392	3.8e+05	0.0000		
8	0.9057	0.0803	4.3e+05	0.0000		
9	0.9045	0.0228	4.8e+05	0.0000		
10	0.9000	-0.0389	5.3e+05	0.0000		
11	0.8942	0.0480	5.8e+05	0.0000		
12	0.8910	0.1084	6.2e+05	0.0000		
13	0.8902	0.0707	6.7e+05	0.0000		
14	0.8911	0.0779	7.2e+05	0.0000		
15	0.8914	-0.0010	7.7e+05	0.0000		
16	0.8903	0.0089	8.2e+05	0.0000		
17	0.8904	0.0918	8.7e+05	0.0000		
18	0.8927	0.1051	9.2e+05	0.0000		
19	0.8971	0.1257	9.7e+05	0.0000		
20	0.9037	0.1359	1.0e+06	0.0000		

Figure 9.4 – Correlogram of the electricity price itself for the bidding zone NO5 from 2011 to 2017.

LAG	AC	PAC	Q	Prob>Q	-1 0 1 [Autocorrelation]	-1 0 1 [Partial Autocor]
1	0.2276	0.2276	3178.1	0.0000		
2	-0.1396	-0.2018	4373.8	0.0000		
3	-0.1207	-0.0402	5267.6	0.0000		
4	-0.1294	-0.1264	6294.7	0.0000		
5	-0.1066	-0.0795	6992	0.0000		
6	-0.1269	-0.1438	7980.6	0.0000		
7	-0.0853	-0.0839	8427.4	0.0000		
8	0.0157	-0.0261	8442.6	0.0000		
9	0.1037	0.0356	9102.7	0.0000		
10	0.0405	-0.0513	9203.4	0.0000		
11	-0.0801	-0.1112	9597.2	0.0000		
12	-0.0798	-0.0731	9988.4	0.0000		
13	-0.0544	-0.0799	10170	0.0000		
14	0.0194	-0.0008	10193	0.0000		
15	0.0451	-0.0108	10318	0.0000		
16	-0.0374	-0.0935	10404	0.0000		
17	-0.0706	-0.1065	10709	0.0000		
18	-0.0669	-0.1268	10984	0.0000		
19	-0.0704	-0.1367	11289	0.0000		
20	-0.0634	-0.1314	11535	0.0000		

Figure 9.5 – Correlogram of the first difference in electricity prices for the bidding zone NO5 from 2011 to 2017.

LAG	AC	PAC	Q	Prob>Q	-1 0 1 [Autocorrelation]	-1 0 1 [Partial Autocor]
1	0.6644	0.6644	27091	0.0000		
2	0.3678	-0.1318	35395	0.0000		
3	0.2088	0.0360	38070	0.0000		
4	0.1061	-0.0317	38762	0.0000		
5	0.0538	0.0121	38939	0.0000		
6	0.0374	0.0148	39025	0.0000		
7	0.0298	0.0030	39080	0.0000		
8	0.0199	-0.0048	39104	0.0000		
9	0.0105	-0.0032	39111	0.0000		
10	0.0066	0.0036	39113	0.0000		
11	0.0057	0.0022	39115	0.0000		
12	-0.0034	-0.0148	39116	0.0000		
13	-0.0030	0.0102	39116	0.0000		
14	-0.0043	-0.0078	39118	0.0000		
15	0.0018	0.0140	39118	0.0000		
16	0.0102	0.0066	39124	0.0000		
17	0.0185	0.0110	39145	0.0000		
18	0.0254	0.0096	39185	0.0000		
19	0.0387	0.0255	39277	0.0000		
20	0.0809	0.0733	39678	0.0000		

Figure 9.6 – Correlogram of the electricity price itself for the market area Great Britain from 2011 to 2017.

LAG	AC	PAC	Q	Prob>Q	-1 0 1 [Autocorrelation]	-1 0 1 [Partial Autocor]
1	-0.0581	-0.0581	207.12	0.0000		
2	-0.2049	-0.2090	2784.5	0.0000		
3	-0.0840	-0.1160	3217.3	0.0000		
4	-0.0751	-0.1428	3563.3	0.0000		
5	-0.0534	-0.1274	3738.1	0.0000		
6	-0.0132	-0.1027	3748.7	0.0000		
7	0.0034	-0.0860	3749.4	0.0000		
8	-0.0008	-0.0807	3749.4	0.0000		
9	-0.0082	-0.0809	3753.6	0.0000		
10	-0.0044	-0.0736	3754.8	0.0000		
11	0.0122	-0.0527	3763.9	0.0000		
12	-0.0142	-0.0736	3776.2	0.0000		
13	0.0026	-0.0518	3776.6	0.0000		
14	-0.0111	-0.0699	3784.2	0.0000		
15	-0.0033	-0.0585	3784.8	0.0000		
16	0.0000	-0.0595	3784.8	0.0000		
17	0.0022	-0.0549	3785.1	0.0000		
18	-0.0097	-0.0674	3790.9	0.0000		
19	-0.0430	-0.1097	3904.1	0.0000		
20	-0.0505	-0.1443	4060.8	0.0000		

Figure 9.7 – Correlogram of the first difference in electricity prices for the market area Great Britain from 2011 to 2017.

9.12. The augmented Dickey-Fuller test for stationarity

The augmented Dickey-Fuller test for stationarity of the electricity price level, i.e. the electricity price itself, in the bidding zone NO5 and the market area Great Britain is presented in Table 9.9. To account for the autocorrelation mentioned in section 9.11, the augmented Dickey-Fuller test includes six lags for the bidding zone NO5 and three lags for the market area Great Britain.

	NO5	GB
Test statistic	-15,944***	-96,720***

Table 9.9 – The augmented Dickey-Fuller test for stationarity for the electricity price level in the bidding zone NO5 and the market area Great Britain from 2011 to 2017. *p $< 0,10$, **p $< 0,05$, ***p $< 0,01$.

The null hypothesis state that there is a unit root. The null hypothesis can be rejected at a 1 % significance level for NO5 and Great Britain.

9.13. Historical weekly price structure of NO5 and Great Britain

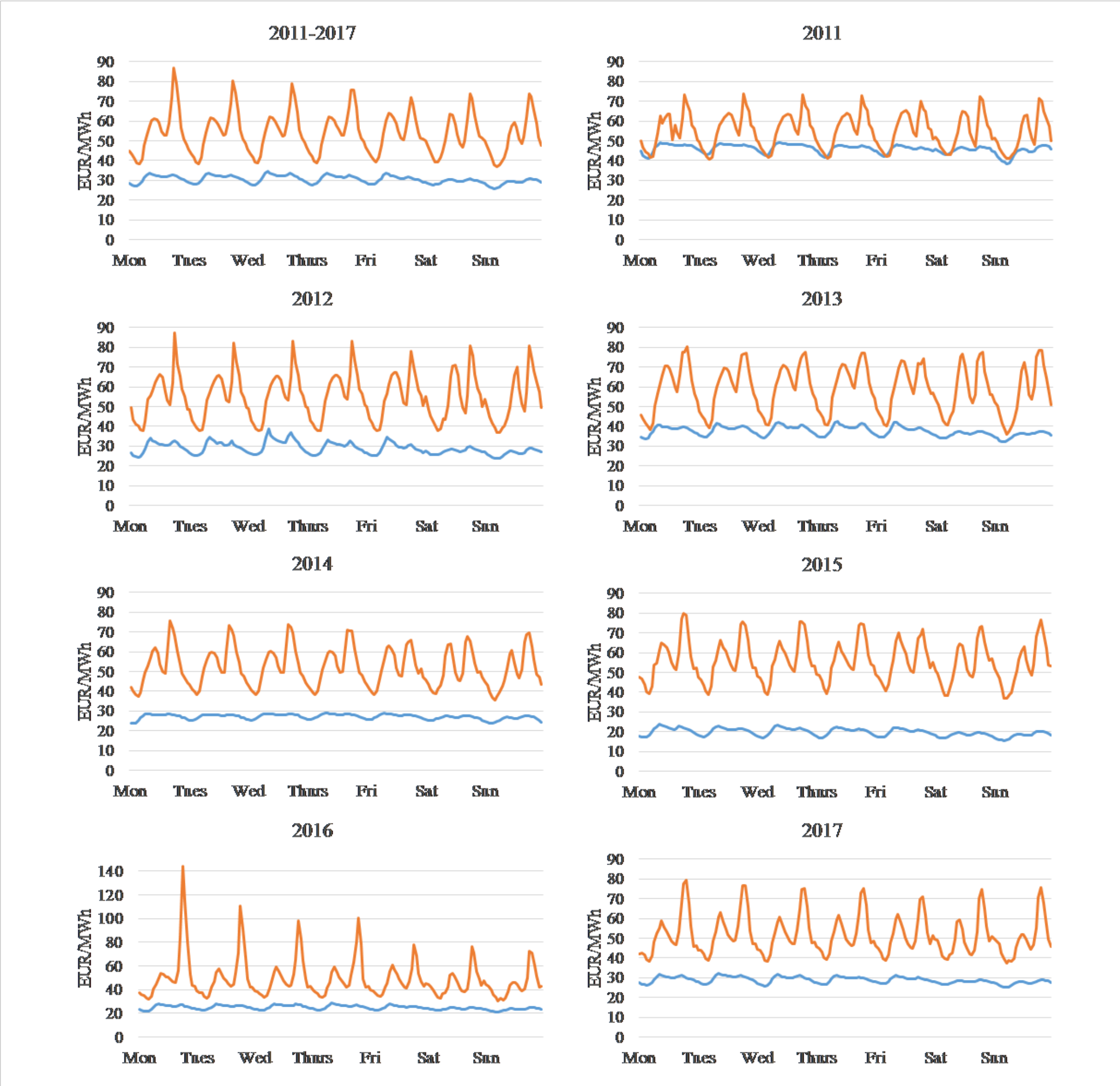

Figure 9.8 – The historical weekly price structure in NO5 (blue) and Great Britain (orange) shown as the average electricity price in €/MWh for each hour of the week for the period from 2011 to 2017 as a whole and for each year.

9.14. Historical monthly price structure of NO5 and Great Britain

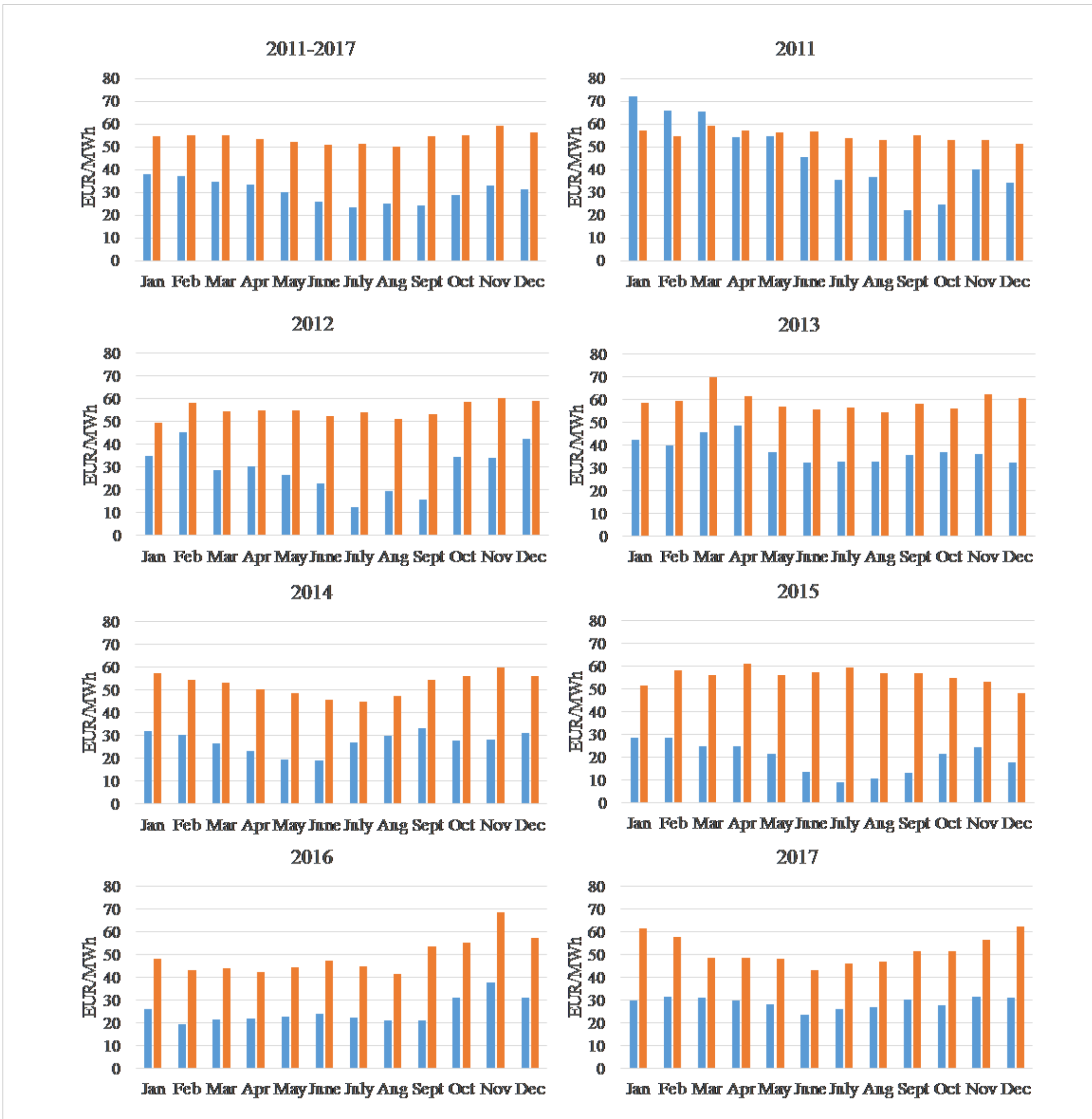

Figure 9.9 – The historical monthly price structure in NO5 (blue) and Great Britain (orange) shown as the average monthly electricity price in €/MWh for the period from 2011 to 2017 as a whole and for each year.

9.15. Monthly historical volatility of electricity prices in Great Britain

Based on the approach of Liski and Vehviläinen (2016), the electricity price volatility for each month is given by equation (9.3).

$$\sigma_{\text{monthly}} = \sqrt{\frac{\sum_{t=2}^{m}(r_t - \bar{r})^2}{m-2}} \tag{9.3}$$

Where $r_t = \frac{p_t}{p_{t-1}}$ is the price ratio of the electricity price p_t for hour t, $\bar{r} = \frac{\sum r_t}{m-1}$ is the average price ratio during a month and m is the number of hours in a month.

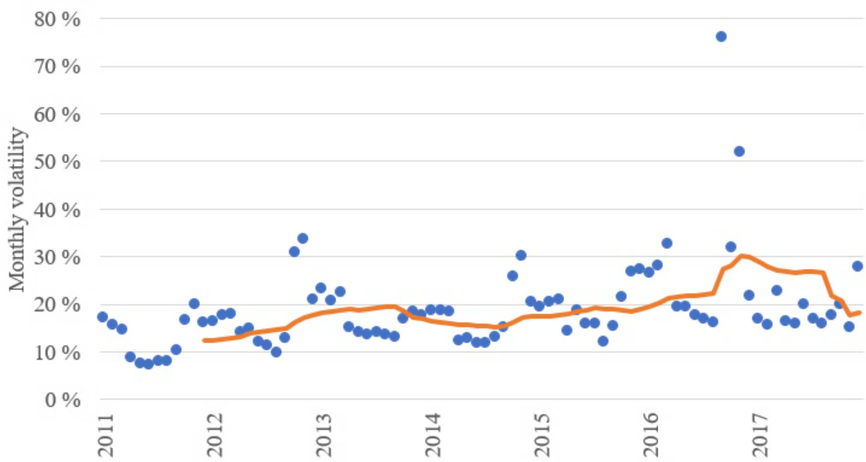

Figure 9.10 – The monthly historical volatility of electricity prices in percent for GB, from 2011 to 2017. The solid line represents the 12-month moving average monthly historical volatility.

9.16. Sensitivity analysis of historical electricity prices in Great Britain

Series	N. Obs.	Mean	Median	Min.	Max.	Std. Dev	Skew.	Kurt.
D: Cold season								
p_t	30 621	55,85	51,83	5,14	894,70	20,55	9,68	287,83
$p_t - p_{t-1}$	30 620	-0,0003	-0,60	-665,44	754,20	18,60	3,79	389,03
$\ln p_t$	30 621	3,98	3,97	1,64	6,80	0,28	0,50	8,01
$\ln p_t - \ln p_{t-1}$	30 620	-0,0000	-0,01	-1,72	2,04	0,19	0,64	10,07
E: Warm season								
p_t	30 744	52,13	51,23	1,80	1174,92	18,18	25,86	1370,38
$p_t - p_{t-1}$	30 743	-0,0002	-0,17	-822,18	1116,11	12,82	6,34	2937,15
$\ln p_t$	30 744	3,92	3,94	0,59	7,07	0,25	-0,14	9,53
$\ln p_t - \ln p_{t-1}$	30 743	-0,0000	-0,004	-2,23	2,99	0,14	0,09	16,75

Table 9.10 – Alternative descriptive statistics of the hourly electricity prices in €/MWh in GB for the period 2011 to 2017. In this sensitivity analysis the cold season is from October through March, and the warm season from April through September.

9.17. Historical correlation coefficient of NO5 and Great Britain

	GB11	GB12	GB13	GB14	GB15	GB16	GB17	N11
GB11	1							
GB12	0,76	1						
GB13	0,75	0,68	1					
GB14	0,60	0,60	0,63	1				
GB15	0,62	0,54	0,57	0,63	1			
GB16	0,33	0,34	0,30	0,45	0,39	1		
GB17	0,51	0,56	0,52	0,62	0,48	0,38	1	
N11	**0,23**	0,04	0,16	0,05	0,05	-0,06	0,11	1
N12	0,12	**0,29**	0,14	0,24	-0,02	0,06	0,37	0,31
N13	0,26	0,13	**0,36**	0,18	0,18	-0,00	0,14	0,43
N14	0,04	0,14	0,16	**0,30**	0,02	0,09	0,32	-0,19
N15	0,21	0,19	0,22	0,28	**0,10**	0,07	0,30	0,60
N16	0,07	0,20	0,15	0,27	0,00	**0,26**	0,25	-0,17
N17	0,22	0,32	0,25	0,29	0,08	0,12	**0,37**	0,19

	N12	N13	N14	N15	N16	N17
N12	1					
N13	0,19	1				
N14	0,14	0,08	1			
N15	0,58	0,51	0,05	1		
N16	0,24	-0,04	0,08	0,21	1	
N17	0,37	0,22	0,34	0,37	0,14	1

Table 9.11 – Electricity price correlation coefficient ρ of the power markets NO5 and Great Britain for each year from 2011 to 2017.

9.18. Histogram of annual historical price differential

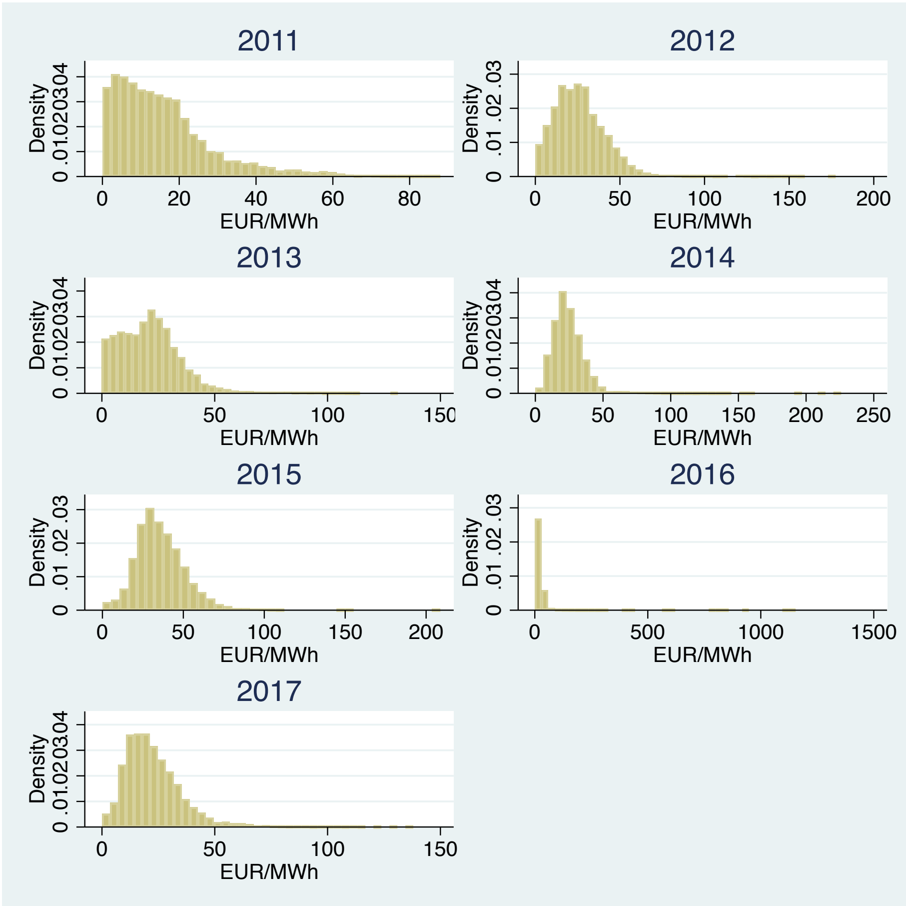

Figure 9.11 – Histogram of the annual historical hourly electricity price differential in absolute numbers $|z_t|$ between NO5 and Great Britain in €/MWh for each year from 2011 to 2017.

9.19. Percentiles of the price differential between NO5 and Great Britain

Percentiles	1 %	5 %	10 %	25 %	50 %	75 %	90 %	95 %	99 %
EUR/MWh	0,80	4,12	7,37	13,83	22,09	31,98	43,57	52,36	75,96

Table 9.12 – The percentiles of the historical hourly electricity price differential in absolute numbers $|z_t|$ between NO5 and Great Britain for the period 2011 to 2017 in €/MWh.

9.20. Histogram of hourly historical price differential

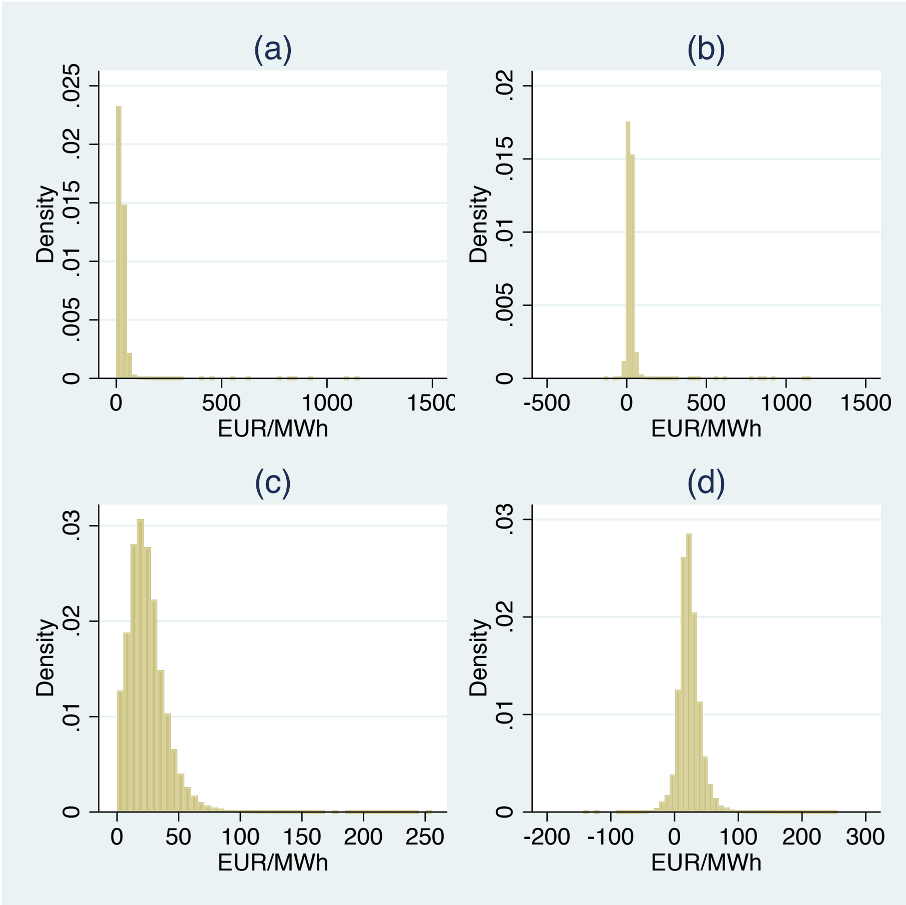

Figure 9.12 – **(a)** The histogram illustrates the distribution of the historical hourly electricity price differential in €/MWh in absolute numbers between NO5 and Great Britain for the years 2011 to 2017. **(b)** The histogram illustrates the distribution of the historical hourly price differential. **(c)** The histogram illustrates the distribution of the historical hourly price differential in absolute numbers when twenty observations of extreme values have been removed from the data set. The extreme values were all observed in 2016 and range from 259 €/MWh to 1154 €/MWh. **(d)** The histogram illustrates the distribution of the historical hourly price differential when twenty observations of extreme values have been removed from the data set. The extreme values were all observed in 2016 and range from 259 €/MWh to 1154 €/MWh.

9.21. Distribution of the historical price differential between NO5 and Great Britain

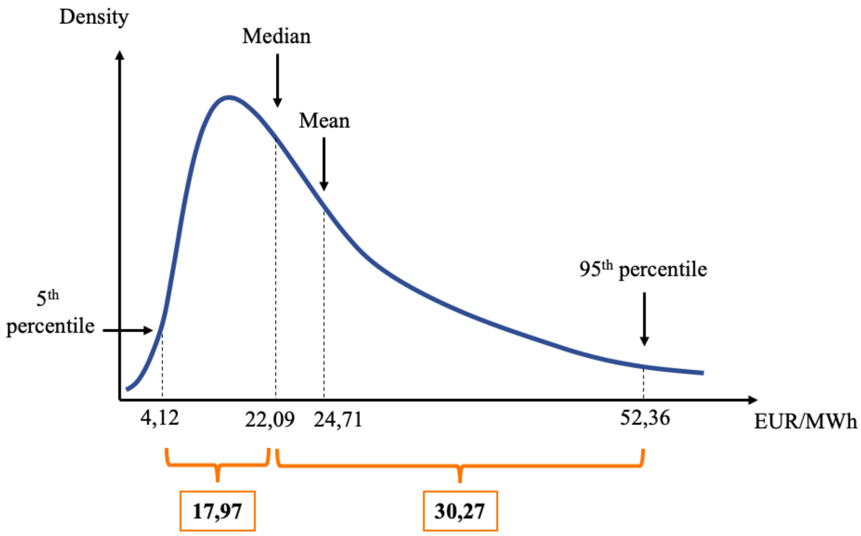

Figure 9.13 – The median, mean, 5$^{\text{th}}$ and 95$^{\text{th}}$ percentile of the historical hourly price differential in absolute numbers from 2011 to 2017. The distribution is positively skewed. The distance between the 5$^{\text{th}}$ percentile and the median is 17,97 €/MWh, whereas the distance between the median and the 95$^{\text{th}}$ percentile is 30,27 €/MWh. Note that the illustrated distribution is not statistically estimated. Authors' own illustration.

9.22. Merit order curve of Great Britain in 2019 and 2030

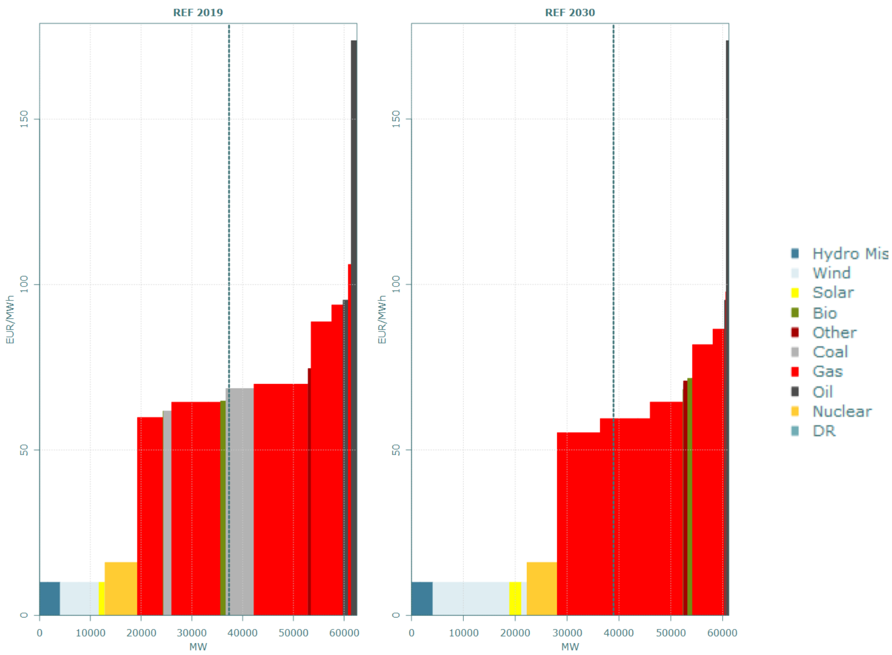

Figure 9.14 – The merit order curve of Great Britain in 2019 (left) and 2030 (right). The curves are produced as output of the TheMA model.

9.23. Estimated retained congestion rent and net interconnector income

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	PV
a) CR	54,1	51,4	63,8	76,2	88,6	104,4	120,2	135,9	151,7	167,5	167,7	167,9	168,0	168,2	168,4	167,6	166,7	165,9	165,0	164,2	
Imports to NO5	7,0	8,0	9,8	11,6	13,4	15,0	16,6	18,2	19,8	21,3	22,5	23,7	24,8	26,0	27,1	28,1	29,0	29,9	30,8	31,7	
Exports from NO5	47,1	43,3	53,9	64,6	75,2	89,4	103,6	117,8	131,9	146,1	145,2	144,2	143,2	142,3	141,3	139,5	137,7	136,0	134,2	132,4	
b) CR cap	54,1	51,4	63,8	76,2	88,6	104,4	120,2	135,9	150,0	150,0	150,0	150,0	150,0	150,0	150,0	150,0	150,0	150,0	150,0	150,0	
c) CR cap&floor	90,0	90,0	90,0	90,0	90,0	104,4	120,2	135,9	150,0	150,0	150,0	150,0	150,0	150,0	150,0	150,0	150,0	150,0	150,0	150,0	
d) CR cap + 5year	66,8	66,8	66,8	66,8	66,8	135,9	135,9	135,9	135,9	135,9	150,0	150,0	150,0	150,0	150,0	150,0	150,0	150,0	150,0	150,0	
Operational costs	46,0	46,0	46,0	46,0	46,0	46,0	46,0	46,0	46,0	46,0	46,0	46,0	46,0	46,0	46,0	46,0	46,0	46,0	46,0	46,0	
Capital costs	5,0	5,0	5,0	5,0	5,0	5,0	5,0	5,0	5,0	5,0	5,0	5,0	5,0	5,0	5,0	5,0	5,0	5,0	5,0	5,0	
a) Net int. income	3,1	0,4	12,8	25,2	37,6	53,4	69,2	84,9	100,7	116,5	116,7	116,9	117,0	117,2	117,4	116,6	115,7	114,9	114,0	113,2	1 124,7
b) Net int. income cap	3,1	0,4	12,8	25,2	37,6	53,4	69,2	84,9	99,0	99,0	99,0	99,0	99,0	99,0	99,0	99,0	99,0	99,0	99,0	99,0	1 003,8
c) Net int. income cap&floor	39,0	39,0	39,0	39,0	39,0	53,4	69,2	84,9	99,0	99,0	99,0	99,0	99,0	99,0	99,0	99,0	99,0	99,0	99,0	99,0	1 112,3
d) Net int. income cap + 5year	15,8	15,8	15,8	15,8	15,8	84,9	84,9	84,9	84,9	84,9	99,0	99,0	99,0	99,0	99,0	99,0	99,0	99,0	99,0	99,0	1 024,4

Figure 9.15 – The retained congestion rent and net interconnector income in million 2018 EUR from 2026 to 2045. a) unregulated, b) a revenue cap of €150 million, c) a revenue cap of €150 million and a revenue floor of €90 million and d) a five-year settlement period with a revenue cap of €750 million. The annualised costs related to capital and operation are the Norwegian share (50 %) of €92 million and €10 million p.a. respectively, estimated in the concession application of NorthConnect from 2017. The net interconnector income is given by the (retained) congestion rent less the capital and operational costs. The present value (PV) of the net interconnector income is derived using a discount rate of 3,1 % (based on Bjørndal and Johnsen (2018)) over 20 years.

9.24. Estimated interconnector flow

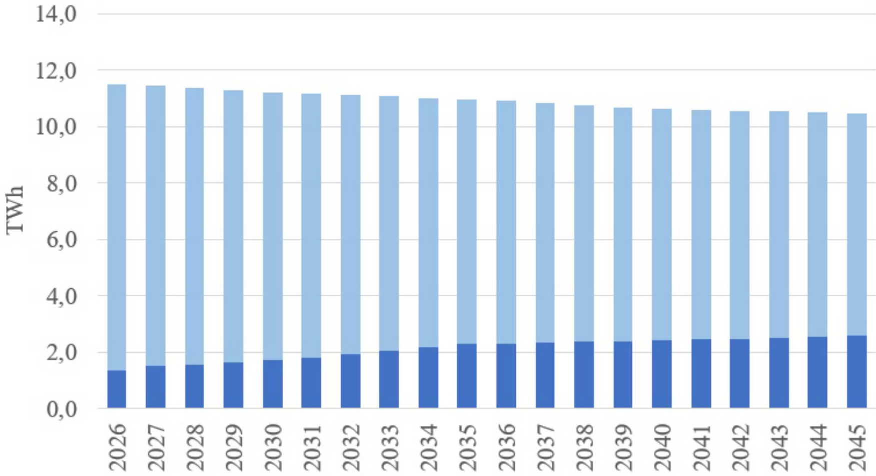

Figure 9.16 – The estimated interconnector flow of a 1 400 MW cable between NO5 and Great Britain in TWh between 2026 and 2045. The interconnector flow constitutes of flow from NO5 (light blue) and flow to NO5 (dark blue).

9.25. Electricity prices and interconnector flows in Northern Europe in 2030

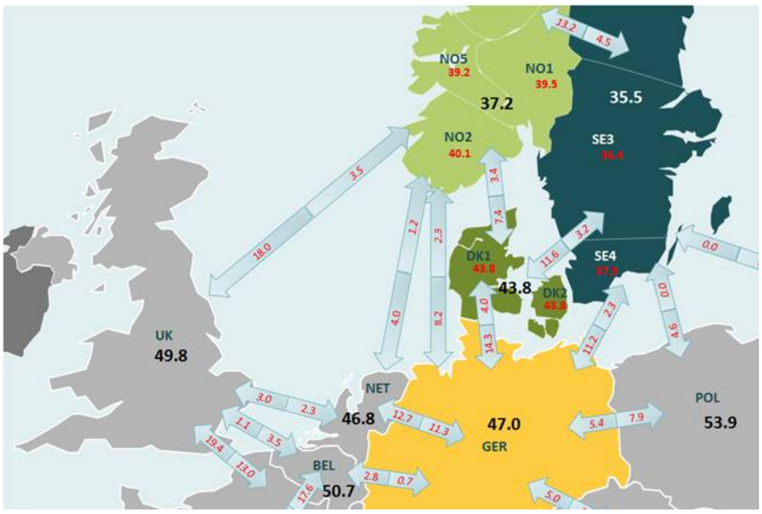

Figure 9.17 – Simulated electricity prices in €/MWh and interconnector flows in TWh for Northern Europe in 2030. The map is an output of the TheMA model.