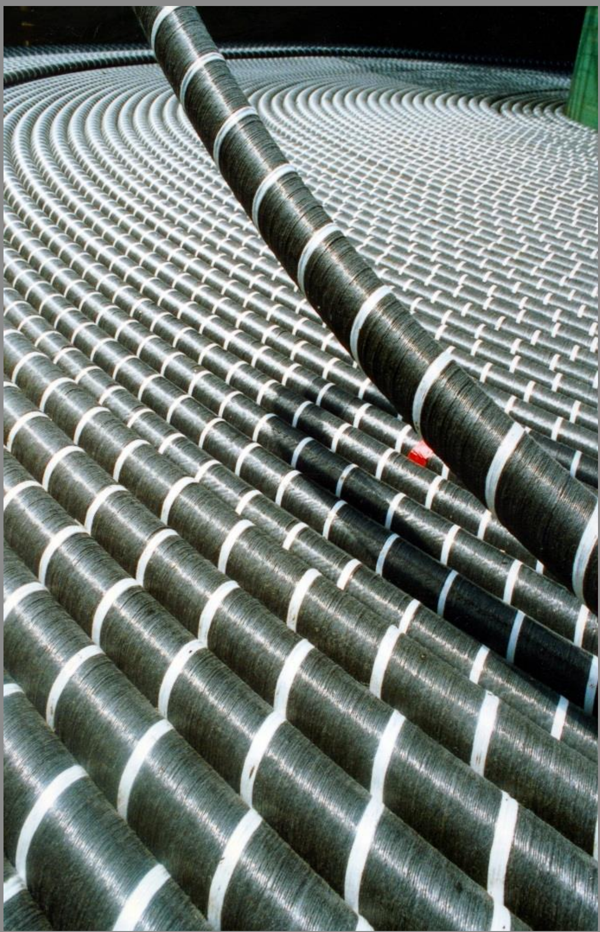
Statnett

Licence application

Interconnector Licence Applications - interconnectors between Norway and Germany, and Norway and Great Britain



May 2013

Statnett

DISCLAIMER

15 May 2013 Statnett SF submitted an application for a licence under Section 4-2 of the Norwegian Energy Act to the Ministry of Petroleum and Energy for facilitation of international power trading for two projects. One of the applications relates to power trading with Germany, while the other deals with power trading with the UK.

The purpose of this English translation of the application is to provide Statnett partners and the relevant authorities in Germany and the United Kingdom insight into what information this Norwegian application contains. Since this version of the application may contain inaccurate translations, we want to emphasize that it is the Norwegian version of the application which is the official version.

Oslo, 28 June 2013

Statnett

Interconnector License Applications - interconnectors between Norway and Germany, and Norway and Great Britain

Statnett SF hereby applies to the Ministry of Petroleum and Energy for a licence under Section 4-2 of the Norwegian Energy Act for facilitation of international power trading for two projects. One of the applications relates to power trading with Germany, while the other deals with power trading with the UK.

These are two independent projects and Statnett is applying for a licence pursuant to Section 4-2 of the Energy Act for each individual project. The basis for the two applications is largely identical, and Statnett has therefore opted to compile the applications in a single document.

We present the analyses of the socioeconomic benefit from day-ahead trading in a separate report attached to this document. The title of the report is «Cables to Germany and Great Britain – analysis of socioeconomic benefit from day-ahead trading».

Statnett is of the opinion that increasing power exchange capacity with other countries by constructing two new interconnectors of 1400 MW each makes good sense for Norwegian society. The planned interconnections to Germany and the UK, which are scheduled for completion in 2018 and 2020 respectively, will:

- Contribute to increase value creation in Norway while also being socioeconomically profitable
- Reinforce security of supply, particularly as regards securing access to energy in dry years
- Contribute to the development of a more climate-friendly energy sector by facilitating the adopted commitment to renewable energy in Norway and Sweden, and by supporting the conversion of energy systems for our trading partners.

Oslo, 15 May 2013

Auke Lont

President and CEO

Håkon Borgen

Executive Vice President, Projects Division

CONTENTS

DISCLAIMER II
INTERCONNECTOR LICENSE APPLICATIONS - INTERCONNECTORS BETWEEN NORWAY AND GERMANY, AND NORWAY AND GREAT BRITAIN III
CONTENTS V

SECTION I BASIS 1

SECTION II TRADE SOLUTIONS APPLIED FOR 8
1 GERMANY 9
2 THE UK 11

SECTION III SOCIOECONOMIC PROFITABILITY 13
3 ABOUT THE PROJECTS 14
4 COMPARISON OF SOCIOECONOMIC EFFECTS IN NORWAY 16
5 EXPECTED BENEFIT FROM DAY-AHEAD TRADING 22
6 OTHER BENEFIT 27
7 COST ESTIMATES 33
8 ROBUSTNESS AND SENSITIVITIES 38

SECTION IV APPENDICES 57
1 SOCIOECONOMICS – METHOD AND ASSUMPTIONS 58
2 CHANGES IN THE TARIFF BASIS 65
3 GRID REINFORCEMENTS AND SYSTEM OPERATIONS 69
4 ORGANISATION OF THE GERMAN POWER SECTOR AND POWER MARKET 82
5 ORGANISATION OF THE UK POWER SECTOR AND POWER MARKET 85
6 THE GERMANY PROJECT 88
7 THE UK PROJECT 93

SECTION I BASIS

This section briefly explains the significance of interconnectors for Norway. We also explain why Statnett believes it is necessary to expand the power trading capacity by connecting the Norwegian power system to systems with which we have not previously had direct interconnectors.

The need for interconnectors has been based on security of supply, efficient resource utilisation and value creation. In particular, trading opportunities contribute to improved resource use for unregulated renewable power production, including unregulated Norwegian hydropower. The interconnectors will make it easier to replace fossil power with renewable power while also maintaining security of supply.

Statnett's analyses show that the socioeconomic benefit of increasing trading capacity is both high and robust. The main reason is that the interconnectors contribute to more efficient resource use as power will flow from the country with the lowest price to the country with the highest price. This creates a high socioeconomic benefit within a wide spectrum of potential future development paths.

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Increased value creation, better security of supply and fewer greenhouse gas emissions

By licence, Statnett SF (Statnett) has been assigned the role of Transmission System Operator (TSO) in Norway. As the TSO, Statnett must ensure instantaneous balance between overall production and overall consumption of power, considering the power exchange with associated foreign systems. Statnett is responsible for ensuring efficient operations in a social economy perspective and for developing the main power grid.

The company wishes to achieve several objectives by expanding the power trading capacity with surrounding systems. How these objectives are weighted will differ according to the different stakeholders. The three overarching social policy goals are:

- Ensure increased **value creation** for Norwegian society by realising socioeconomic values through exchange of power between Norway and surrounding systems
- Contribute to strengthening **security of supply.** As TSO, Statnett is responsible for ensuring security of supply in the system. This entails ensuring that a physically robust power system is in place, along with functional market solutions. Security of supply is linked to access to sufficient output so that consumption can be covered at maximum loads, and the ability to cover the demand for energy over the course of a year
- Facilitate the phase-in of more renewable power in Norway and surrounding systems, thereby contributing to making power production more **climate-friendly**. The ability to regulate Norwegian hydropower can be utilised both through trading power in the day-ahead market and sale of system and balancing services. Through the interconnectors to Norway, the systems in Germany and the UK will gain access to cheaper and more climate-friendly regulating capacity. This will facilitate the conversion to a more climate-friendly power sector in these countries at a lower cost than would otherwise be the case.

The Nordic and Northern European energy systems are undergoing sweeping structural modifications. In Norway, new power stations need grid access and market access to sell their output at prices which make their investments profitable. This sets new requirements for the future main grid, and power trading across national borders will be even more significant than before, for security of supply, efficient resource utilisation and value creation. A vital element of Statnett's strategy for developing the Norwegian main grid is therefore to increase power trading capacity by constructing two new interconnectors to Germany and the UK. These projects are important for the development of the Northern European power grid and are a top priority for all parties involved. The partners have agreed that the goal for completion should be 2018 and 2020, respectively.

In Proposition to the Storting Prop. 113 L, "Changes in the Energy Act", Chapter 5 "Comments regarding proposed changes", the Ministry provides an account of which considerations will be emphasised in the socioeconomic assessment of when an interconnector licence should be granted. The applications with appendices have been prepared on the basis of these criteria, which should form the basis for a comprehensive assessment of the planned projects' total socioeconomic effects.

Both the Germany and the UK projects have reached a maturity level which Statnett’s Board of Directors has considered sufficient to apply to the Ministry of Petroleum and Energy (MPE) for an interconnector licence pursuant to Section 4-2 of the Energy Act. The projects have been developed in parallel since 2009, and the project schedules are based on Statnett making an investment decision with our partners for both projects in the summer of 2014. The licence applications are therefore submitted at the same time. The amount of cable that will be produced and installed is so substantial that the projects will claim a large part of the existing capacity in the global market for several years to come. The projects' schedules therefore also assume that the supplier industry has sufficient capacity to support the planned progress.

Balanced and socioeconomically profitable development of the power system

Statnett's analyses show that, with the expected development of overall power balance and power prices in the Nordic region and the rest of Europe, it will be socioeconomically profitable for Norway to increase the power trading capacity by another 2800 additional MW. The Norwegian power system is currently connected to surrounding systems through 13 interconnectors with a total transmission capacity of about 5400 MW in and out of Norway. Together with Energinet.dk, Statnett is now building Skagerrak 4, the fourth cable between Norway and Denmark. The 700 MW interconnector is scheduled to start commercial operation on 1 December 2014.

The socioeconomic profitability of the two planned investments, measured in present value, is in the order of NOK 18 billion. In addition, the projects have a number of positive ripple effects that cannot easily be quantified. The calculations show that the investments will have an internal rate of return of 10-11 %, which is high for infrastructure projects. The repayment period is short, about 10-11 years. After this, we will have two fully repaid interconnectors that will yield substantial benefits for Norwegian society throughout their technical lifespan, which could be up to 60 years.

The analyses show that the benefit is relatively robust vis-à-vis variations in several key assumptions. The main reason is that the cables can transfer power in both directions. The power follows the price signals from the connected power markets, and flows from the market with the lowest price to the market with the highest price. During some periods, the power flows almost continuously in one direction while there are frequent changes in the flow direction in other periods. It is this characteristic of power trading which gives the cables increased resource utilisation and thus a high socioeconomic reward within a broad spectrum of possible future development paths.

Generally speaking, international power trading contributes to more efficient exploitation of overall power plant resources. When all available production resources are shared in this way, the respective individual countries can get by with a lower installed production capacity without suffering negative consequences for security of supply. This means a lower need for investment, which also makes a positive contribution to the socioeconomic benefit of power trading.

Statnett's plans to increase the power trading capacity alone will help shape the development of the Norwegian power system in the years ahead. We must expect that they are included as assumptions in forecasts of future prices used as a basis for capital budgeting for players that will invest in new renewable power production, and that changes in our plans may thus have an impact on existing investment plans and thereby on the future development. Statnett believes the new interconnectors are well-aligned with the development we anticipate and that they are necessary to ensure a balanced and thus rational development of the Norwegian power system.

Strengthened security of supply and efficient resource utilisation

In the Norwegian hydropower system, where the annual water inflow can vary by about 60 TWh, and where the water inflow varies considerably throughout the year, power trading with our neighbouring countries has been a financially efficient method to balance hydrological fluctuations. The reservoir plants' ability to shift the production in time without incurring costs enables the hydropower system to also deliver short-term flexibility to the surrounding thermal systems. By using power cables and other interconnectors to trade power this ability is turned into value creation on both sides.

- During periods with power deficits, power trading helps secure access to energy and thus increases security of supply.
- In surplus situations, trade ensures that the renewable energy is put to use in other countries. It replaces output from thermal plants, and we achieve good resource utilisation while also facilitating reduced greenhouse gas emissions.

- Even in situations where net energy imports or exports are not needed, large volumes of power are traded over the interconnectors. This happens since the direction of the power flow is determined by the price signals from the interconnected power markets. Power flows from the market with the lowest price to the market with the highest price. Historically, the pattern has been that power flows to the thermal systems during the peak load periods in the daytime, and in the opposite direction during the off-peak periods in the evening and at night. We expect that an increasing element of volatile wind and solar power generation in the systems around us will manifest as more frequent shifts in the flow of power via the interconnectors.

An increase in power trading capacity of 2800 MW will strengthen Norwegian security of supply. The expected increased power surplus and construction of other new interconnectors from the Nordic region entail that the planned cables' significance in relation to securing energy access for Norway and the Nordic region will , in the short term, be less than for existing interconnectors. However, in the long term, power system developments may change this. In particular, the coal fired power plants in Finland and Denmark have benefitted as flexible producers in the Nordic region. Several Danish plants have already been shut down, and even more will be phased out as the competition from new renewable electricity generation becomes stronger. However, by using the interconnectors to Germany and the UK, Norway can, if necessary, import more power in less time, from more trade partners and at lower prices. Such a need can also arise if we, for example, experience problems with Swedish nuclear power production combined with low water inflow and winter temperatures. The probability of reservoirs running empty and rationing being imposed in spring when reservoir levels are generally low is also reduced.

A greater power surplus and more unregulated output when consumption is low will increase the need for export in the summer months. The revenues from export will be higher when the power trading capacity is increased. This partially explains the high socioeconomic benefit of the planned cables. We will have higher congestion revenues, receive better payment for net export and have a lower risk of water loss, which also means we will be able to use our resources more efficiently.

Trade revenues through day-ahead trading, trade in balancing services and participation in capacity markets

All day-ahead trading via the cables will be run by the new market connection algorithm developed for all of North-Western Europe. This entails that the transmission capacity is allocated through implicit auction, which provides the most effective capacity utilisation.

Congestion revenues from day-ahead trading, together with changes in producer and consumer surplus, are expected to constitute the largest contribution to power trading gains from the planned cables. We expect an additional benefit due to a high power surplus and a lot of unregulated production. But this does not mean that future benefit depends on this being the situation for the cables' entire lifetimes. In a situation with a deficit, we will also have high gains, but then mostly through cheaper import during dry years. During winter and spring, nearly all of the gains are in the form of congestion revenues, as a lot of wind and little sun result in the greatest price volatility on the Continent side during these periods. During summer and autumn, the need to export surplus power results in both high gains in the form of increased producer and consumer surplus and considerable congestion revenues, even though the price volatility in the markets we plan to connect with is relatively low at this time of year.

For both cables, the intention is to establish a trade solution which allows use of up to 300 MW for trading of automatic reserves. Balancing services trading generates potential higher revenues beyond energy day-ahead trading. We have estimated the higher revenue for Norway at NOK *50 million/year,* if we have a dynamic model that continuously allocates up to 300 MW of the transmission capacity for balancing services trading. The fact that the model is dynamic entails that, during some periods, 300 MW is used for balancing services trading, while less is used in other periods.

Development of new, renewable power production facilities is moving quickly and the authorities in several countries are worried about whether the market will provide a sufficient volume with reliable capacity to maintain security of supply. To ensure capacity, several countries are planning to utilise so-called capacity mechanisms. The side effect of implementing such measures is that the price peaks during periods with low renewable production and high consumption would be reduced. This results in lower price volatility and thus lower expected revenue from trading via the interconnectors.

The UK has come far in preparing for introduction of a capacity market. Germany has not yet decided to introduce such a market, but both the need and various approaches are being discussed. Empirical analyses show a clear correlation between flow, in the Skagerrak cables and NorNed, and prices in western Denmark and the Netherlands, respectively. With sufficiently high prices in these countries, i.e. when they have a scarcity of capacity, they have received full import from Norway. The planned interconnectors will contribute to the security of supply in Germany and the UK. We have therefore made it clear to partners and authorities that we assume the cables will be treated equally with national capacity and thus be compensated in future capacity markets. The estimated compensation is used as a basis in the profitability analyses for the planned interconnectors. If this assumption is not fulfilled, this could have consequences for the investment decisions.

Trade with new markets generates price and distribution effects

Several factors will impact the power prices in Norway in upcoming years. We expect the power prices to gradually increase up to 2030, in the Nordic region and the rest of Europe. The most important reasons for this are international factors outside of Norway's control, namely that the price of fuel and carbon is expected to rise. These factors determine the short-term marginal operating costs in thermal power stations and are the single most important factor for long-term price development in the Nordic region. The expected increase in the carbon price is particularly important. We assume that the carbon market will be used as an important instrument in reducing greenhouse gas emissions leading up to 2030, and that the quota price will be high enough to reach the goals for emission cuts. As a consequence of this assumption alone, the power price in Norway and the Nordic region in 2020 will be NOK 0.09 – 0.10/kWh higher than today.

The future carbon prices and the role the quota market will play as an instrument in climate policy are associated with considerable uncertainty. The current quota prices are very low, and there is a real possibility the carbon prices determined in the quota market will play a smaller part than other instruments such as subsidies for renewable power production, strict emission requirements for thermal power stations or a fossil fuel tax. The key point in this context, however, is that the marginal costs for thermal power stations will still be decisive as regards the Norwegian price level, despite the fact that Norway has nearly no thermal power stations. This will remain largely unaffected by the planned interconnectors.

The rapid development of renewable energy (and nuclear power in Sweden and Finland) will increase the power surplus, thus resulting in a lower price level, all else being equal. The ratio between the surplus in the Nordic power balance and total transmission capacity out of the area has a major impact on the price level. Following marginal production costs for thermal power stations, this factor has the biggest impact on long-term development of power prices in the Nordic region and in Norway. We would like to emphasise that in this context, the Norwegian overall power balance is only significant through its participation in the total Nordic balance. For example, if Sweden and Finland together have a major surplus, and Norway is in balance, new interconnectors from Norway will result in export of this surplus as well as higher prices in the entire Nordic region.

The phase-in of 45 TWh of new emission-free power up to 2020 will in isolation push prices in Norway, Sweden and Finland down. Without other adjustments, such production growth would result in very low prices compared with the rest of North-Western Europe, and a total price collapse for certain periods. But the markets adapt to expected price trends. However, we believe the actual surplus will be about 30 TWh due to consumption growth and because some fossil production will be phased out. Other adaptations, such as the expected transition to flexible trading between Finland and Russia will also help alleviate the price decline.

There is no simple and clear correlation between an increase in trading capacity and changes in the power price. Statnett considers the new interconnectors to be part of a balanced set of measures, where the development of the determined volume of new renewable power production assumes increased trading capacity with our neighbouring systems. Overall, these measures will, in most scenarios, contribute to reducing the Norwegian power price compared with a situation where the investments are not carried out.

We have nevertheless analysed a hypothetical, and probably unrealistic, situation where the renewables effort is carried out fully even if the cables are not built. Based on these assumptions, the analyses show that, seen in isolation, an increase in power trading capacity of 2800 MW will contribute to increasing the average price in Norway by between approx. NOK 0.025 and NOK 0.04/kWh in 2020.

However, it is not a given that the renewables effort will be fully implemented if the cables are not built. Moreover, there could be other adaptations such as increased power consumption in the industry and in the heating sector in the Nordic countries as early as 2020, and there could be smaller expansions in nuclear power than expected. Particularly in a time perspective beyond 2020, consumption and production will adapt to a changed price level, and thus dampen the price effects from trading.

We have examined how the analysis results are influenced by changes to our assumptions regarding the power balance in 2020 and 2030, but we have not analysed alternative development paths (with long-term changes to production and consumption) if the cables are not built. All experience shows that both the production capacity and consumption level will adapt to a changed price level over the long term, but it is very difficult to say where such changes will take place, which price level will trigger changes in various sectors and how quickly such adaptations will take place.

The analyses also show that the cables will impact the power prices in the markets we connect to. The price differences between the markets will be somewhat smaller. We expect the price in Norway around 2020 to be about NOK 0.045/kWh lower than the German price and about NOK 0.11/kWh lower than the UK price. We expect the UK to have a higher price level than Germany due to the carbon tax on fossil fuels that will be introduced, and because the UK is more dependent than Germany on gas fired power stations with higher marginal production costs.

An increase in the producer and consumer surplus constitutes a large part of the total Norwegian benefit from day-ahead trading in our basic estimates both in 2020 and 2030. The market benefits in the rest of the Nordic region come in addition. In simple terms, we could say that the increase in the producer and consumer surplus arises through the following three factors:

- Better paid export during periods with a more long-term need for net export
- Cheaper import during periods with an import need
- More pronounced price structure throughout the day

The basic estimates also assume that the surplus in the power balance in the Nordic region will increase from the current 10 TWh to about 30 TWh in 2020 and will then stabilise. In Norway we have assumed that, in a normal year, the surplus will increase from the current 4 TWh to about 12 TWh in 2020 before decreasing to 7 TWh in 2030. For Norway it is also significant that much of the surplus comes from unregulated hydropower where production is highest during the summer months when the export need is already at its highest. The largest benefit from producer surplus is therefore expected in the period from mid-May to late September where we will receive a large share of unregulated output. Of a total of 12 TWh in expected average annual export, given a situation with a considerable power surplus, 80% will take place during summer and autumn. During winter, the new interconnectors will generate somewhat higher export volumes from Norway during the day, but due to capacity constraints these volumes will be smaller than for the rest of the year. On the other hand, import during night-time increases significantly. This results in somewhat greater price variation throughout the day.

With a major Nordic surplus, the need for import to the Nordic region will be low even in very dry years. The benefit for consumers of cheaper import during dry years is therefore low in our basic estimates. However, considerable uncertainty is associated with the scenario assumptions, particularly in the long term. Various forms of long-term adaptations with a basis in a surplus situation will contribute to reducing the power surplus, which will eventually result in a larger consumer surplus. It is therefore not unlikely that the distribution effects in a 40-year perspective will be different than what is indicated in our basic estimates.

We expect that the price effect in Norway of building a cable to the UK will be about the same as to Germany, though the price level is expected to be higher in the UK. There is no direct correlation between the average price difference between two markets and the price impact of connecting the markets. The size of exports and imports impacts prices in Norway, not trade partners' power prices. The power flow runs every hour from the market with the lowest price to the market with the highest price. As long as the price difference is sufficient to yield profitable trade, the transmission capacity is fully exploited. A major price difference between the countries will thus not change the trading volume – and therefore does not create any other price impact in Norway.

A new interconnector will primarily affect the price level in Norway based on the *net export* generated by the interconnector. The net export is determined by the number of export hours less the number of import hours. The duration of periods with high and low prices in the markets to which we connect and variations in the Norwegian price (wet year/summer, dry year/winter) will be decisive as regards what type of trading pattern we will have and thus the magnitude of the net export we will see over time on a new interconnector. This is why trade with the UK is expected to yield about the same price effect as trade with Germany, although the price level will most likely be higher in the UK.

If an interconnector yields net export and increases the price level, this price effect will reduce the net export in other interconnectors out of Norway and the Nordic region. Thermal power production in the Nordic region will also produce more when the prices are higher, and export opportunities could result in less spillage of water in situations with a major hydropower surplus. These effects are included in the model calculations we described earlier. What the model calculations do not include, however, is more long-term adaptations in consumption and production: A somewhat higher price level in Norway, Sweden and Finland makes it more profitable to invest in new or expanded power production. In particular, improved export opportunities in wet years can make it profitable to expand production capacity in hydro-electric power plants so one can utilise the water inflow more efficiently. Somewhat higher prices in the Nordic region will also dampen consumption. These effects will contribute to a clear reduction in price effects, compared with what is indicated by the model calculations.

The relevant interconnectors both have a power trading capacity of 1400 MW

The decision is founded on three factors:

- *Profitability:* The profitability increases substantially with increased capacity. This is because the revenue per MW of additional capacity increases considerably more than the costs
- *Technical cable restrictions:* With the existing implementation plans for our projects, the only realistic alternative is to use conventional cable technology. This will result in a transmission voltage of 525 kV. 1400 MW is a natural upper limit when using this type of technology
- *System restrictions: The cable capacity is limited by dimensioning simultaneous loss of load in the interconnected systems. A capacity of 1400 MW is adapted to this limit*

The German cable will be connected to the Norwegian grid in Tonstad (Sirdal), and the UK cable in Kvilldal (Suldal).

SECTION II TRADE SOLUTIONS APPLIED FOR

In this section we explain how the transmission capacity in the new interconnectors will be used. The chosen trade solutions will provide the best utilisation of the planned transmission capacity in economic terms.

1 GERMANY

The cable will be used for energy trading (day-ahead and intraday trading), as well as trade in balancing services. Financial transmission rights (FTR) can also be sold.

1.1 Trading in the energy market

To prevent socioeconomically unprofitable trading, trading should only be carried out when the price difference is at least as large as the marginal cost of the transmission loss over the cable. A more detailed description of expected loss costs associated with transmission via the cable is provided later in the application.

1.1.1 The day-ahead market

Day-ahead trading via the cable will, as for our other interconnectors, be carried out through market coupling / implicit auction by the capacity being included in a joint market algorithm for Europe. This entails that prices and flows are determined simultaneously. This will ensure optimal commercial flow in the interconnector.

1.1.2 The intraday market

Intraday trading will be included in the European intraday platform that is under development. The trading platform will be designed in such a way that all bids and offers are gathered in a joint European order book. The German cable will then facilitate for Norwegian players to be able to trade intraday with players in all of Europe.

1.1.3 The long-term market

TSOs can sell long-term transmission rights. Long-term transmission rights can be designed as so-called "Financial Transmission Rights" (FTR). FTRs are purely financial products, where the owners have a right to payment equal to the day-ahead price difference between the areas. Assuming well-functioning power markets, financial transmission rights will not impact the physical flow in the cable, and the effectiveness of the trade will thus not be reduced as a result of the TSOs selling FTRs.

It is not desirable to exclude the possibility of trading transmission rights

Statnett has no tradition for selling long-term transmission rights, and currently has no plans to do so. At the same time, it is not desirable to exclude the possibility that sale of FTRs could be relevant in the future. To safeguard this possibility, it is opened up for the parties to sell the congestion revenue through FTRs.

If the parties have different preferences with regard to a potential sale of FTRs, each party can individually decide over their share of the capacity that is reserved for the energy market. In this connection, Statnett has considered the parties' incentives and the efficiency of the flow, and such a solution has not been found to result in unfortunate consequences.

- The parties will still have coinciding incentives for operation and maintenance of the cable. Both parties will still lose revenue if the cable is not operational and will want to repair it as quickly as possible. The loss will be lost congestion revenues and/or compensation for sold transmission rights
- The decisive factor for whether the flow in the cable is impacted is the properties of the products and the conditions related to use of the products that are traded, and not that the parties could have different financial allocation of the capacity.

Long-term transmission rights will be sold via a trading platform

If long-term transmission rights become relevant, they must be sold in an organised marketplace. A separate auction platform can be established, as for BritNed, or it can be done via an established platform, such as the TSO-owned company Capacity Allocation Service Company (CASC). Norwegian players will be able to trade FTRs via such a platform. It will thus not be necessary to establish a separate auction company in order for Statnett to be able to sell FTRs, or for Norwegian players to have access to these.

Furthermore, it cannot be excluded that the future European regulations for long-term transmission rights that are being drafted will entail that the parties are required to sell transmission rights via the interconnector.

1.2 Trade in balancing services

Up to 300 MW will be allocated to trade in balancing services, assuming it is at least as profitable as trading in the day-ahead market. A dynamic allocation mechanism is planned, so that the capacity that is actually allocated to trade in balancing services could vary between nil and 300 MW depending on profitability. Assessments of operational reliability can limit how much capacity can be allocated to trade in balancing services.

1.2.1 Trade model

At a general level, Statnett wants the dynamic allocation mechanism to be able to function as follows:

- Each day/week/month, the transmission capacity is distributed to energy and balancing services trading, respectively. It will be reasonable to adjust the length of the period to the purchasing system for reserves in at least one of the countries.
- The distribution of the transmission capacity is determined based on: a) prices for purchase of reserves and prognoses for power prices and b) evaluation of previous periods' relative profitability.

ENTSO-E is in the process of preparing a proposal for joint European regulations for trade in balancing services. The regulations are expected to include a requirement for allocation of capacity for trade in balancing services to be approved by involved regulators. It e.g. involves that the regulators will approve the allocation model, the length of allocations and the framework for which volumes can be allocated to trade in balancing services.

A description of the agreed allocation mechanism will be presented prior to the investment decision.

The value of allocating transmission capacity to trade in balancing services is described later in the application.

2 THE UK

The cable will be used for energy trading (day-ahead and intraday trading), as well as for trade in balancing services. Trade in financial transmission rights (FTR) or physical transmission rights can also take place.

2.1 Trading in the energy market

To prevent socioeconomically unprofitable trading, trading should only be carried out when the price difference is at least as large as the marginal cost of the transmission loss over the cable. It should also be assessed whether other costs should be taken into consideration.

2.1.1 The day-ahead market

Day-ahead trading via the cable will, as for our other interconnectors, be carried out through market coupling / implicit auction by the capacity being included in a joint market algorithm for Europe. This entails that prices and flows are determined simultaneously. This will ensure optimal commercial flow in the interconnector.

2.1.2 The intraday market

Intraday trading will be included in the European intraday platform that is under development. The trading platform will be designed in such a way that all bids and offers are gathered in a joint European order book. The UK cable will then facilitate for Norwegian players to be able to trade intraday with players all over Europe.

2.1.3 The long-term market

TSOs can sell long-term transmission rights. Long-term transmission rights can be designed as FTR or so-called PTRs (Physical Transmission Rights). FTRs are purely financial products, where the owners have a right to payment equal to the day-ahead price difference between the areas. PTRs are sale of physical transmission capacity which gives the owner the right to use the capacity. There are different variants with regard to which possibilities and commitments the owner has if the capacity is not used.

The interconnector flow will still be efficient

Financial transmission rights: Sale of FTRs is a purely financial agreement on pre-sale of congestion revenues, realised via the day-ahead market, and will not impact the physical flow in the cable, assuming well-functioning power markets. The effectiveness of trading will therefore not be reduced.

Physical transmission rights: Assuming well-functioning power markets, efficient flow in the cable will be ensured through:

- PTR owners must sell non-nominated capacity to the day-ahead market in line with the Framework Guidelines for Capacity Allocation and Congestion Management
- A so-called netting mechanism must be established for nominated flow, which ensures the physical flow will always be efficient.

It is not desirable to exclude the possibility of trading in transmission rights

Statnett has no tradition for selling long-term transmission rights, and currently has no plans to do so. At the same time, it is not desirable to exclude the possibility that sale of transmission rights could be relevant in the future. To safeguard this possibility, it is opened up for the parties to sell the congestion revenue through FTRs or PTRs.

If the parties have different preferences with regard to a potential sale of transmission rights, each party can individually decide over their share of the capacity that is reserved for the energy market. In this connection, Statnett has considered the parties' incentives and the efficiency of the flow, and such a solution has not been found to result in unfortunate consequences.

- The parties will still have coinciding incentives for operation and maintenance of the cable. Both parties will still lose revenue if the cable is not operational and will want to repair it as quickly as possible. The loss will be lost congestion revenues and/or compensation for sold transmission rights.
- The decisive factor for whether the flow in the cable is impacted is the properties of the products and the conditions related to use of the products that are traded, and not that each party decides over their share of the capacity independently. With the conditions described for use of PTRs above, efficient flow will be ensured.

The products will be sold via a trading platform

Long-term transmission rights must be sold in an organised marketplace and the players must qualify to trade there. A separate auction platform can be established, as for BritNed, or it can be done via an established platform, such as the TSO-owned company Capacity Allocation Service Company (CASC). Norwegian players will be able to trade FTRs or PTRs via such a platform. It will thus not be necessary to establish a separate auction company in order for Statnett to be able to sell FTRs or PTRs, or for Norwegian players to have access to these.

Furthermore, it cannot be excluded that the future European regulations for long-term transmission rights that are being drafted will entail that the parties are required to sell transmission rights via the interconnector.

2.2 Trade in balancing services

Up to 300 MW will be allocated to trade in balancing services, assuming it is at least as profitable as trading in the day-ahead market. A dynamic allocation mechanism is planned, so that the capacity that is actually allocated to trade in balancing services could vary between nil and 300 MW depending on profitability. Assessments of operational reliability can limit how much capacity can be allocated to trade in balancing services.

2.2.1 Trade model

At a general level, Statnett wants the dynamic allocation mechanism to be able to function as follows:

- Each day/week/month, the transmission capacity is distributed to energy and balancing services trading, respectively. It will be reasonable to adjust the length of the period to the purchasing system for reserves in at least one of the countries.
- The distribution of the transmission capacity is determined based on: a) prices for purchase of reserves and prognoses for power prices and b) evaluation of previous periods' relative profitability.

ENTSO-E is in the process of preparing a proposal for joint European regulations for trade in balancing services. The regulations are expected to include a requirement for allocation of capacity for trade in balancing services to be approved by involved regulators. It e.g. involves that the regulators will approve the allocation model, the length of allocations and the framework for which volumes can be allocated to trade in balancing services.

A description of the agreed allocation mechanism will be presented prior to the investment decision.

The value of allocating transmission capacity to trade in balancing services is described later in the application.

SECTION III SOCIOECONOMIC PROFITABILITY

New interconnectors to Germany and the UK are socioeconomically profitable, with good robustness in various scenarios.

In this section we provide a comprehensive picture of the socioeconomic profitability of the planned interconnectors. A description of the most vital assumptions is also provided.

Furthermore, we highlight the uncertainty in the cost and benefit estimates and robustness in the socioeconomic analysis.

3 About the projects

Throughout the years, Statnett has planned and constructed several HVDC (high-voltage direct current) cables; currently, we have interconnectors to Denmark (Skagerrak 1-3) and the Netherlands (NorNed), and Skagerrak 4, the fourth interconnector to Denmark, is under construction. Important lessons from history:

- Trading power with our neighbours has been necessary and profitable for Norwegian society through several decades where the overall power balance has fluctuated between major surplus and deficit
- Cable projects have long lead times, and it is challenging to develop them up to an investment decision. In the 1990s there were plans for two cables to Germany (Viking Cable and Euro Cable), but neither were realised. The plans for a subsea cable to the UK (the NSI project) were developed for four years before the project was stopped in 2003

The historic experience and results from analyses carried out in 2008 were key motives for establishing a larger portfolio of interconnector projects. In fact, Statnett's analyses showed that the revenues from energy trading as a result of increased power trading capacity with surrounding systems would be high, while also improving security of supply.

The Germany project

The Germany project is a cooperation between Statnett and DC Nordseekabel GmbH & Co KG ("DCNG").

The German interconnector will have a nominal capacity of 1400 MW. The connection points for the cable will be at Tonstad on the Norwegian end of the cable, and in Wilster on the German end. Statnett will own the northern half of the interconnector and the onshore facilities in Norway. DCNG will own the southern half of the interconnector and the onshore facilities in Germany.

DCNG is a German company, indirectly fully-owned by TenneT TSO GmbH ("TenneT") and KfW, each with 50%.

TenneT is one of four TSOs in Germany. In the same manner as Statnett, TenneT administers the main grid and the interconnectors, monitors the reliability and reliability of supply and ensures balance between production and consumption of power. TenneT is a subsidiary of TenneT B.V. which is currently fully-owned by the Dutch state. TenneT in the Netherlands is Statnett's partner for the NorNed cable, of which each of the parties own 50%.

KfW is a German, state-owned finance institution. KfW was founded in 1948 as part of the Marshall Plan, and the name is originally from Kreditanstalt für Wiederaufbau.

The project's history goes back to 2008 when Statnett and *Transpower Stromübertragungs GmbH* (formerly E.ON Netz GmbH) re-started the work on considering a cable between Norway and Germany. The project was called NORD.LINK. The feasibility study that was carried out concluded that the project was socioeconomically profitable for both countries and that the development should be continued into the next phase. In November 2009, *Transpower* was sold to TenneT. This transaction was completed in February 2010. The acquisition resulted in the termination of the cooperation with *Transpower* and Statnett continued the project development alone.

In June 2010, Statnett increased its ownership interest to 50% in the NorGer project, a project that was established in 2006 with the purpose of building a 1400 MW interconnector to Germany. The planned revenue model for NorGer was a so-called commercial interconnector that needed an exemption from the regulations for allocation of the congestion revenues. The other owners were Agder Energi, Lyse and Swiss EGL. The objective of purchasing NorGer was to ensure a coordinated development of the transmission capacity between Norway and Germany, as well as to increase the probability of realisation of the interconnector by having two options. However, the development that took place following the acquisition indicated that it would be difficult to realise both projects at nearly the same time which the original project plans assumed. The other owners then chose to sell their shares in the project to Statnett. Later, when TenneT bought in to the NORD.LINK project, they also purchased 50% of NorGer's ownership interests.

The UK project

The UK project is a cooperation between Statnett and National Grid NSN Link Limited ("NSN Link").

The nominal capacity of the UK interconnector will also be 1400 MW. The connection points for the cable will be in Kvilldal on the Norwegian end of the cable, and in Blyth on the UK end. Statnett and NSN Link will each own a physical half of the interconnector and onshore facilities.

NSN Link is a UK company indirectly fully-owned by National Grid Holding 1 Limited ("NGH1"). NGH1 is the holding company for the National Grid Group's activity in the UK, and is directly and indirectly fully-owned by National Grid Plc.

The ultimate parent company National Grid Plc. is listed on the London Stock Exchange, as well as the New York Stock Exchange. The National Grid Group owns and operates transmission grids in England, Wales and the US. In England and Wales, the transmission grid is owned through the subsidiary National Grid Electricity Transmission Ltd. ("NGET"), which is also the TSO for England and Wales and system operator for the UK. The National Grid Group is the partner on the UK side in existing and planned interconnectors to the UK.

From 1997-2003, Statnett and National Grid cooperated on developing the North Sea Interconnector cable project of 1200 MW ("NSI"). Statnett applied for a licence for the project in 2003, but the licence application was rejected, and the project was then terminated. The cooperation with National Grid was sporadically followed up in the years after the NSI project was terminated. The market development showed that a cable would be more profitable than assumed in 2003. In 2008 alone, half of the investment in NSI would have been paid off. The cooperation was therefore resumed in 2009 with the aim of assessing whether the possibility of building a subsea cable between Norway and the UK had changed significantly. After this, the partners applied the knowledge from the NSI project to develop a new project that is better adapted to the regulatory framework in both countries.

Other projects

During implementation of the NorNed project, a possible expansion of the power trading capacity at a later date was partially facilitated. In August 2009, Statnett and TenneT decided to collectively conduct a small feasibility study in order to make a decision for potential commissioning of the development of a NorNed2 project. However, different prioritisation of projects in Statnett and TenneT resulted in the project being considered unrealistic to realise within acceptable timeframes.

In the NorGer project, partners Statnett and TenneT have agreed to complete the process of applying for a technical licence in Germany. There are no on-going activities related to development of the project in Norway, and the partners will decide how to use a potential German licence at a later date.

Statnett has no other international projects under development apart from those discussed in these two licence applications. Cable projects of this scope have lead times of approximately 10 years. It is therefore not likely that other Statnett projects will reach a maturity level that comes close to these projects over the course of the next few years.

4 COMPARISON OF SOCIOECONOMIC EFFECTS IN NORWAY

This section compares the socioeconomic effects of the planned cable interconnectors consisting of a list of priced effects and assessment of non-priced effects.

The following investment alternatives are relevant:

- Alternative 0 – No new interconnectors (reference alternative)
- Alternative 1 – New interconnector to Germany in 2018
- Alternative 2 – New interconnector to the UK in 2020, assuming that alternative 1 is built as planned in 2018
- Alternative 3 – New interconnector to the UK in 2020

This way of describing the alternatives entails that alternative 2 shows the marginal effect of constructing a cable to the UK when a cable to Germany is already in operation. For alternative 3 we show the effects of only developing the UK project, i.e. without constructing the Germany cable. All figures in this chapter are real, i.e. have been converted to 2013 NOK. The conversion was carried out based on expected inflation in 2013. All assumptions presented in Chapters 4-7 are in 2012 NOK. The method of calculation is described in more detail in Appendix 1.

4.1 Priced effects

This section shows the annual priced effects with associated present values of the interconnectors.

(Million 2013 NOK, Norwegian share)	1)Germany	2) The UK| Germany	3) The UK
Annual values:			
Congestion revenues in cable	650	720	770
Trade in reserves	50	50	50
Revenues from capacity mechanisms	120[1]	120	120
Producer and consumer surplus	650	480	630
Congestion revenues from other interconnectors	-170	-170	-180
Operating and maintenance costs	-20	-25	-25
Transit costs	-8	-30	-30
System operation costs	-125	-125	-125
Transmission loss in the Norwegian grid	-100	-60	-60
Investment costs:			
Investment cost in cable and station	-6 400	-6 950	-6 950
Net cost domestic grid reinforcements	- 2 000	-1 500	-700

[1]From and including 2020

Table 1: Estimates of annual revenues and costs for the planned interconnectors. Investment costs (p50) for the actual facilities and for the necessary reinforcements of the Norwegian main grid that can be attributed to the cables' need. Some figures were rounded off in the presentation compared with the actual figures used in the calculations.

Present value (million 2013 NOK, Norwegian benefit)	1)Germany	2) The UK| Germany	3) The UK	Portfolio (total alt. 1 and 2)
Congestion revenues in cable	10 600	11 100	11 900	21 700
Trade in reserves	850	750	750	1 600
Revenues from capacity mechanisms	1 900	1 850	1 850	3 700
Investment cost in cable and station	-5 600	-5 750	- 5 750	-11 350
Operating and maintenance costs	-3 50	-350	-350	-700
Total project profitability	**7 400**	**7 600**	**8 400**	**15 000**
Producer and consumer surplus	10 800	7 400	9 800	18 200
Congestion revenues from other interconnectors	-2 750	-2 600	-2 700	-5 350
Transit costs	-150	-500	-500	-650
System operation costs	-2 000	-1 850	-1 850	-3 850
Transmission loss in the Norwegian grid	-1 600	-850	-850	-2 450
Net cost domestic grid reinforcements	-1 750	-1 200	-550	- 2 950
Residual value	150	100	50	250
Socioeconomic profitability for Norway	**10 100**	**8 100**	**11 800**	**18 200**
Internal rate of return	11%	10%	13%	
Repaid this year	2029	2031	2028	

Table 2: Calculated socioeconomic profitability for Norway. The total of the two projects indicates society's gains from implementing both projects.

As indicated in the table, the projects are socioeconomically profitable with a good margin, both individually and collectively. The following chapters document and discuss the most important figures.

4.1 Non-priced effects

It is not possible to satisfactorily determine the value of all relevant effects of the projects. However, the factors could be of considerable significance for the socioeconomic assessment. The following section assesses the non-priced effects of the cable interconnectors, whether they be consequences for Norwegian security of supply, the power market or climate and environment.

4.1.1 Security of supply

Security of supply means the system's ability to meet end users' demand for power with a certain quality at all times (energy access). Historically, the consideration for security of supply has been a very important driver for development of power trading capacity from Norway. This is because the Norwegian and Nordic power system experiences hydrological fluctuations that can be balanced through trading with other countries. This helps reduce negative consequences of lasting shortage of water inflow through access to power import.

All new trading capacity to surrounding power systems helps strengthen Norwegian security of supply. An expected increasing Nordic power surplus in combination with new transmission interconnectors still means that the cables to Germany and the UK, in the short term, will be less significant for security of supply than the existing interconnectors.

Beyond Statnett's plans, several other new transmission interconnectors from the Nordic region are under development. Relevant projects are:

- NordBalt between Sweden and Lithuania
- Cobra between Denmark and the Netherlands
- Jutland and Germany
- Sweden and Finland
- Sweden and Germany
- An interconnector between Denmark and the UK is also under discussion

At the same time, the two projects will have long lifespans, while our analyses are based on the power situations in 2020 and 2030. In the long term, after 2030, it is possible, and perhaps probable, that Norway and the Nordic region will experience a tighter power market balance than what our analyses indicate for 2030. Consumption in Norway and the Nordic region may increase as a result of new establishments and general consumption growth, while the Danish coal fired power plants and Swedish nuclear power plants may be shut down. In general, a tighter power market balance will reduce the calculated benefit, but increase the cables' significance for security of supply through energy access. The increased transmission capacity thus becomes a real option. If and when the transmission capacity is needed with regard to energy access, the cables will provide a positive contribution.

The future market development is uncertain and the cables provide the systems on both sides with more flexibility to also handle other development paths than what we consider most likely today. With 2 800 MW more in power trading capacity, Norway can, when needed, import more in less time and at a lower price than without the cables. Such a need could quickly arise if we enter into a period with problems in Swedish nuclear power production combined with low water inflow and winter temperatures as recently experienced. Together with the other upgrades of the main grid, the cables will enable the Norwegian power system to handle most situations and needs that may arise over the next 40 years.

Given the major changes planned in our surrounding power systems, and the uncertainty this entails, we will achieve increased security of supply by connecting the Norwegian power system to two major power markets which we are not already connected to. Statnett therefore considers the planned interconnectors to be of strategic significance for Norway.

4.1.2 A more well-functioning power market in the Nordic region and Europe

Increased trading capacity with markets outside the Nordic region stimulates increased competition in the power market. All purchase and sale bids are included in a joint optimisation process that involves more players than if trading was not possible. Players on both ends of the interconnector can meet in a common market, only restricted by transmission capacity. When transmission capacity is not restricted, prices and liquidity are shared. The risk of exercising market power is generally reduced when competition increases.

New interconnectors between the markets will furthermore result in increasing long-term price stability. Long-term price stability is improved as a result of a reduction in price fluctuations from annual variations in water inflow. Increased trading between two areas reduces the uncertainty with regard to future power prices, which is beneficial for both producers and consumers. Reduced uncertainty normally makes it easier for power producers and consumers to make the correct investment decisions while it can also contribute to increased liquidity in the financial power markets.

Some of the consequences of a more well-functioning power market are detected in the priced effects. Overall, we believe the cables have a positive supplementary effect on the Nordic power market beyond what is detected in the priced effects.

4.1.3 The environment

An impact assessment for the environment, natural resources and society at large is presented in the application for a construction licence for the Germany interconnector. The main conclusion is that the environmental consequences will be greatest in connection with the actual construction period and installation of the cable. In Vollesfjord, there is a risk of conflicting with already known protected cultural heritage sites in the sea, and this must be taken into consideration in the detailed engineering of the facility. When the cable is covered, the environmental consequences are minimal. The cable will be marked both in the sea and on maritime charts.

For large parts of the section between Vollesfjord and Ertsmyra in Sirdal, the overhead line will run parallel with existing upgraded 300/420 kV power lines. During the construction phase, the consequences will consist of noise and disturbances for both people and wildlife locally on the parts of the section where the construction work and transport are taking place. The solution involves insignificant exposure disadvantages for populated areas, and the consequences for the landscape and environment are acceptable. The converter in Ertsmyra is shielded from view.

On the German end there is a rich wildlife and nature conservation interests that must be safeguarded in the sea areas. Landing the subsea cables will require minor landscape interventions.

Correspondingly, the consequences of the UK interconnector have been assessed in connection with the construction licence application from 2001. Our upcoming supplementary application for the connection point in Kvilldal will also describe this in detail. The main conclusion is that the facility in itself results in very minor environmental consequences, since the power runs in subsea and ground cables from station to station. Co-localisation of the rectifier facility at the Kvilldal power station will cause negative consequences for the nature and environmental interests. Assuming good communication with fishing and shipping interests during installation of the cable, no special consequences are expected during the construction phase. The consequences are minimal during the operations phase.

Overall, the projects alone will have a relatively minor effect on the environment in Norway. Domestic grid reinforcements that are necessary for the two cable projects also have environmental impact. The environmental consequences of upgrading the voltage of the Western Corridor have been considered in the concept decision assessment for the next generation main grid in South-Western Norway. The assessment concluded that there would be minor environmental costs of implementing the voltage upgrade. In the same assessment, the value of new renewable power production in western Norway was considered to have positive environmental effects. This is not discussed further here.

For the UK project, the costs of Sauda-Samnanger are relevant, and other relevant costs should then also be described. In the on-going work on this project, the environmental consequences are considered insignificant, as this deal with upgrading the voltage of the existing power line.

The cables could result in somewhat more price structure in Norway and thus provide increased incentives for running power stations that, in turn, could have disadvantages for nature. The NVE (Norwegian Water Resources and Energy Directorate) has released a report on the "Environmental impact of rapid changes in water levels". A few observations from the report:

- Hydropower stations with outlets to a river that are being used as peaking plants (i.e. max output during short time periods) have a substantially greater risk of generating negative effects for physical and biological conditions compared with power stations with outlets to reservoirs, lakes and fjords.

- If it is technically feasible to carry out slow changes in the power production, this will reduce the negative effects on the entire ecosystem.
- The risk associated with rapid changes in water levels is greater during winter than summer in Norway as low water temperatures directly and indirectly lead to lower mobility in fish.
- Hydropower stations that are operated as peaking plants and other variable operation patterns that does not result in major changes in water-covered area, will generally not have major physical and biological effects beyond typical regulation effects already known through traditional power station operation.

The environmental challenges will vary from power station to power station, and will depend on operational patterns and potential restrictions. Statnett assumes that environmental challenges will be handled through licence terms, etc.

Overall, the projects alone will have a relatively minor effect on the environment in Norway.

4.1.4 Climate

The two planned interconnectors are an important precondition for a well-functioning Norwegian/Swedish power market and thus facilitate the planned development of 26.4 TWh of new renewable power in Norway and Sweden. Without new interconnectors that enable allocation of surplus power during wet years, we expect a significantly reduced willingness to invest in new power production.

This way, the new interconnectors will contribute to more emission-free power production, which can either form the basis for increased electrification of Norwegian industry or in households, or be exported and replace fossil power production in the rest of Europe.

Furthermore, the new interconnectors will contribute to the further integration of the northern European power market and strengthen the entire power system. The projects will support the ambitions to increase generation of renewable energy throughout the region and the EU's climate and energy targets. Several European countries are in the process of developing major renewable energy production that depends on backup power because it is less flexible. Development of the power trading capacity between countries makes it easier to restructure the European power systems from thermal power production to new renewable power production.

More interconnectors from Norway will help European countries like Germany and the UK to continue their large-scale development of pure wind and solar power. This allows the countries to carry out their political plans to phase out fossil energy production and to cut greenhouse gas emissions. This restructuring contributes to reduced carbon emissions by allowing new renewable power production from the Nordic region to compete with, and possibly replace, polluting power stations in Europe.

Unlike most other countries in Europe, Norwegian power production generates almost no carbon emissions, and it is also flexible. Norway is therefore an important contributor in the form of utilising our hydropower production to balance the growing power production in Europe that cannot be regulated. In order to achieve major emissions reductions in Europe, the countries must cooperate and increase trading capacity.

Since nearly all Norwegian power production takes place without greenhouse gas emissions, a reduction or increase in production will have little effect on Norwegian emissions. However, if there is a possibility for international trading, changes in Norwegian power production and consumption could impact international carbon emissions. However, the exact correlations are complex as a result of the quota market and the uncertainty in the long-term production composition and consumption development in Europe.

The existence of a carbon market with constant quotas entails that reduced emissions from the power sector provide available quotas that can be purchased by others. From this perspective, the total volume of emissions remains unchanged. Reduced power consumption and access to renewable power production could have positive effects when new and potentially lower quotas for emissions are determined. In any case, the decisions will finally be based on political ambitions, and not exclusively the access to renewable power production.

Increased international trading capacity, and possibilities for replacing polluting power production with emission-free power production, must be assumed to have a positive effect on emissions, even though the effect on long-term emissions is uncertain.

4.1.5 Real options

When domestic grid enhancements are realised, we still expect available capacity in the relevant parts of the Norwegian transmission grid. The interconnectors therefore do not displace other profitable projects. The available capacity has a value (real option), as it provides the possibility of increased use of the grid in the future, for example to more renewable power, new industry or further increases in power exchange. Overall, the measures could substantially increase the transmission capacity in the relevant grid. The positive value of the real option reduces the cost that will be attributed to the interconnectors.

It is uncertain how much available capacity there will be at this time, as well as what the capacity will be used for in the future. This makes it very difficult to determine the real option's value. We have therefore chosen not to put a figure on the option value.

5 EXPECTED BENEFIT FROM DAY-AHEAD TRADING

5.1 The expected annual benefit for Norway is EUR 120 to 160 million per cable

When the planned interconnectors to Germany and the UK enter operation, they will provide the systems on both ends with greater flexibility, and we will thus achieve greater utilisation of all power stations. This will generate a major socioeconomic benefit for both Norway and our trade partners.

- Thermal production in Germany and the UK will help the Norwegian-Swedish power system handle hydrological fluctuations by producing more when it is dry and less when it is wet
- Hydropower that can be regulated in Norway and Sweden delivers short-term flexibility to the markets in Germany and the UK by moving production in time

Our estimates for expected Norwegian benefit are EUR 120 to 160 million per year and per cable, when using all of the transmission capacity in the day-ahead market. The total Nordic benefit is a great deal higher, as Sweden in particular will receive a major benefit from the Norwegian cables. From a Nordic perspective, this strengthens the socioeconomic benefits of the projects.

The cables will make Norwegian power prices more similar to prices in Germany and the UK. At the same time, our analyses show that there will still be bottlenecks and major price differences most of the time, even with two times 1400 MW of increased trading capacity. Both price differences and more similar prices contribute to the socioeconomic benefit, in the form of congestion revenues and increased producer and consumer surplus, respectively.

Year	**2020**		**2030**	
Country	Germany	The UK	Germany	The UK
Congestion revenue from cable	83	102	79	86
Other congestion revenues	-21	-22	-20	-20
Increase in total Norwegian producer and consumer surplus	85	69	78	57
Total benefit	147	149	137	123

Table 3: Our estimates for expected benefit in 2020 and 2030, when using all of the cable capacity in the day-ahead market. Figures in million EUR.

As expected, we see a declining marginal benefit of increased transmission capacity out of the Nordic area. This has two important implications for our estimates:

- There will be a reduction in congestion revenues from existing interconnectors. This lowers the estimates for annual Norwegian benefit with about EUR 20 million per cable
- The benefit of the UK cable will be somewhat reduced as it will come after the Germany cable

Due to the declining marginal benefit the congestion revenues presented in the table for the Germany cable are higher than what they will actually be if we build both. When the UK cable enters operation, the congestion revenue from the cable to Germany is reduced, but in order to highlight the marginal benefit of the second cable, this reduction was added to the accounts for the UK cable, under the item “other congestion revenues».

Our analyses show a clear pattern for how the various parts of the benefit are distributed between the seasons. During winter and spring, nearly all of the gains are in the form of congestion revenues, as a lot of wind and little sun result in the greatest price volatility on the European side during these periods. During the summer and autumn period, the need to drain surplus power provides both high gains in the form of increased producer and consumer surplus and considerable congestion revenues, though the price volatility at the opposite end of the cables is relatively low. In total, nearly 70 % of total day-ahead trading benefit will come during the summer and autumn period.

The cables help strengthen security of supply, though, initially, an increasing power surplus reduces the cables' role in ensuring energy access in Norway and the Nordic region. With 2 800 MW more in power trading capacity, Norway can, when needed, import more in less time and at a lower price than without the cables. Such a need can also arise if we, for example, experience problems with Swedish nuclear power production, combined with low water inflow and winter temperatures.

5.2 Different system properties provide a major benefit from trading

The properties of the hydropower-dominated production in Norway and Sweden are currently fundamentally different from the thermal production that is found in Germany and the UK. We anticipate that there will still be major differences throughout the cables' lifespans. This results in significant price differences on an hourly basis and is thus the fundamental reason why the cables provide such a large socioeconomic benefit.

In Norway and Sweden, about 60-70% of the current total power production comes from hydropower, and, of this, regulated production constitutes about 60%. Regulated hydropower can modify production in line with the demand at nearly no cost. The ability to store water over time also makes it possible to move much of the production to periods with high prices. This results in considerably less short-term price variations in the Nordic region[2] than in Germany and the UK, where high regulation costs in thermal power stations generate high price volatility. Up to 2030-50, we assume that much of the fossil-based production will be replaced by unregulated solar and wind power. However, we anticipate that thermal power stations will still play an important role in the price formation. Combined with a larger percentage of prices approaching zero, as a result of more renewables, this will create short-term price volatility in these countries far exceeding the Norwegian in the future as well. Different regulation costs are thus a significant driver for the cables' expected congestion revenues.

The large percentage of hydropower in the Norwegian-Swedish system has advantages, but also challenges. Firstly, a large part of the hydropower is unregulated, where the majority of the production takes place in the summer months when consumption is at its lowest. Secondly, the inflow fluctuates considerably from year to year. In Norway alone, annual water inflow to existing hydro-electric power plants can vary between 90 and 150 TWh. The effect of temperature fluctuations that are positively correlated with the fluctuations in inflow comes in addition. In total, these challenges result in a great need for power trading capacity with neighbouring countries with sufficient levels of thermal production.

Looking ahead, the challenges of handling hydrological fluctuations will increase, particularly with regard to allocating excess production. Three key drivers for this are:

- Larger surplus in power balance in Norway and the Nordic region
- Development of more unregulated production
- Fewer coal power stations in Denmark and Finland

A larger power surplus and more unregulated production when consumption is low will result in a substantial export need during summer months, particularly in years with major water inflow. This increases the socioeconomic benefit of the cables. The congestion rent will be higher, we will receive better payment for the net export and a reduced risk of spillage.

5.3 The cables impact Norwegian prices and result in distribution effects between producers and consumers

When the Germany and UK cables enter operation, we expect prices in Norway and the Nordic region to be impacted in multiple ways. There will be more stable prices throughout the year, but also more short-term price volatility. Since we are assuming an increased Nordic power surplus and more unregulated production, seen in isolation, the cables will also result in a somewhat higher price level in Norway. With the assumptions

[2]The Nordic region usually refers to Norway, Sweden and Finland. Demark has a price pattern that is more similar to that of the Continent.

used as a basis in our basic estimate, our simulations show that the average price in Norway will increase by just under EUR 5/MWh[3] (NOK 0.04/kWh) in 2020 and just under EUR 4/MWh (just over NOK 0.03/kWh) in 2030, when both cables are in operation.

However, it is uncertain how large the price effect will actually be. If there is a lower Nordic surplus than what we have assumed, and a larger transmission capacity with other systems, the price increase will be smaller. If the development goes in the opposite direction, the increase will be larger. In addition to this, the market can adapt to the relatively low price level if the cables are not realised, for example by increasing industry consumption. If this happens there will be higher prices also without the cables, and the cables' actual impact on the price level will be reduced. The extent of such a potential market adaptation is uncertain, but if there is 5-6 TWh increased consumption, our simulations show that the difference in price level with and without cables will be reduced to approx. EUR 3.1/MWh (NOK 0.025/kWh) in our main scenario for 2020.

It is reasonable to look at the changes in price level, and distribution effects between producers and consumers in a larger context.

- Firstly, we expect increased carbon prices to result in a gradual growth in power prices up to 2020 and 2030, regardless of whether we build cables to Germany and the UK or not
- Secondly, the price increase we expect when the cables enter operation should be seen in context with the planned development of renewable power production in Norway and Sweden and the construction of a new nuclear power station in Finland. Together, this will contribute to a larger Nordic power surplus and more unregulated production during the summer months, which, seen in isolation, will result in lower power prices in the Nordic region. The basis for calculating the price impact of the planned interconnectors will thus be a low price level, relatively speaking
- Thirdly, the highest price increases are clearly in the wettest years. The price increase from the cables is therefore not a result of regular price growth alone, but also a consequence of less price variations throughout the year between wet and dry years.

Changed prices in Norway provide a major benefit in the form of increased producer and consumer surplus. At the same time, this results in redistribution between producers and consumers. Which of the two groups ends up the winner and loser on average is closely related to how the prices are impacted.

In situations with power export, the cables will contribute to Norwegian power producers being better paid, while consumers experience a disadvantage with rising prices. The price increase is normally greatest during summer and autumn, and particularly in wet years. Since Norway is a net power exporter in such situations, this means that the cables give Norway a benefit. Since nearly all power production is owned by the Norwegian state, this benefit will go to society at large.

The situation is reversed when it comes to power import. Consumers experience an advantage by having access to cheaper energy, while the power producers lose. The power price will usually decline during winter, particularly in dry years. Since Norway is a net importer in this situation, this means that Norway benefits from the trade.

The common denominator for both situations above is that the total producer and consumer surplus increases when the new interconnectors are established. Norway benefits from trading both with export and import.

In recent years, Statnett has carried out analyses of producer and consumer surplus related to interconnectors in many connections. Experience dictates that it is methodically challenging to estimate the two sizes in isolation, and that they are very sensitive to the analysis assumptions. At the same time, we have experienced that the total producer and consumer benefit is relatively stable and much more robust vis-à-vis changes in the assumptions. It is thus easier to estimate the benefit than how it is distributed between consumers and producers. In the socioeconomic calculation, the total is the relevant figure.

[3] Conversion was done by assuming an exchange rate of NOK 8 per EUR.

The energy balance is primarily what determines the benefit distribution between consumers and generators, i.e. whether export or import will dominate over time. Our analyses have assumed a substantial power surplus in 2020 and 2030. There will thus be a majority of export and the power producers will experience the greatest benefit. However, considerable uncertainty is associated with development of the energy balance, particularly in a long time perspective. The new interconnectors will most likely be operational for 60 years, until 2080. History shows that in a long time perspective we must also expect long periods with a power deficit, and in this perspective, the benefit distribution could turn out differently.

5.4 Many uncertainties result in many possible outcomes

Several of the most important drivers for the cable benefit are closely related to the future development of the power systems in the UK, Germany, Norway and the rest of Europe. This is uncertain, and the development of several of the drivers is therefore burdened with considerable uncertainty. This means that our estimates for expected benefit are uncertain. Our analyses show that the following factors are most significant for the uncertainty of the estimates:

- The size of the Norwegian/Nordic power surplus throughout the year and during the summer season
- The number of cables from Norway and Sweden, and the effect of more flexible trading between Russia and Finland
- The price level of thermal fuels and carbon quotas
- The degree of consumption flexibility in the UK, Germany and in the other countries on the Continent
- The future capacity margin in Germany and the UK
- System and market effects of an increasing percentage of renewables among our trade partners
- Further development of the power systems in Norway, the Nordic region and Europe after 2030

To outline a possible outcome that could last for much of the cables' lifespans, we have prepared a low and high scenario for the cable benefit in both 2020 and 2030 by changing the value of the uncertain factors within the expected variation area. To illustrate the size of the potential outcome for the benefit, we have intentionally adjusted factors that lower (low scenario) and increase (high scenario) the benefit, respectively, in the same direction. The result is that, for each 1400 MW cable, there will be a difference in expected annual benefit of EUR 70 – 90 million between the high and low scenarios.

We believe this provides a realistic picture of the uncertainty, at the same time as it is possible to make assumptions that create a larger outcome. Implicit in the construction of a high and low scenario is an assumption of another market development than that used as a basis for our main scenario. Semi-annual fluctuations in weather and varied fuel prices could, in the same manner as for the basic estimates, result in considerable deviations from this.

It is our assessment that our model simulations provide a representative picture of the situation leading up to 2030-35. At the same time, weaknesses in the model and data basis represent an uncertainty in our estimates. We have taken some of this into consideration by correcting the model results manually where possible.

5.5 The benefit is robust despite the uncertainty

Despite the uncertainties, we consider the benefit to be relatively stable and robust.

The fundamental difference between the hydropower-dominated Nordic power system and the power systems in Germany and the UK, where thermal as well as wind and solar power are dominant, will remain. The fundamental differences in the systems provide fertile ground for profitable trading. The cables will allow for trading both ways, either in the form of nearly continuous flow one way or with frequent changes in the flow direction. This flexibility means that the cables can contribute to increased use of resources, thus creating high socioeconomic gains, in a broad spectrum of future development paths.

Many of the most important drivers for the benefit have low uncertainty. Among other factors, we already have considerable challenges with handling hydrological fluctuations, and hydropower undoubtedly has a substantial potential to move the production in time and thus deliver more short-term flexibility. On the European end, the short-term price volatility could be both greater and smaller than today, but will regardless be greater than in Norway and the Nordic region.

As regards the future market development, much naturally remains uncertain, but the main characteristics are still clear. Europe is heading towards a restructuring of the power system with a significantly higher percentage of renewable production and lower greenhouse gas emissions. Norway and Sweden will have more unregulated production through the certificate market and the entire Nordic region will receive a larger power surplus - the question is how large it will be and how long it will last. This reduces the uncertainty in the cable benefit, particularly for the first ten years of the cables' lifespans.

The major increase in the total producer and consumer surplus also has a stabilising effect on the Norwegian benefit. This spreads the risk, and means that several factors must pull in the same direction in order to have a significant effect on total benefit. The increase in producer and consumer surplus, congestion revenues and loss in existing interconnectors are also closely linked through the cables' effect on Norwegian power prices. During periods where price effects are small, nearly all of the benefit will be in the form of congestion revenue. The total producer and consumer surplus, and congestion revenues from other interconnectors, remain nearly unchanged. However, in periods with major price effects, congestion revenues will be lower, and we will experience considerable loss from existing interconnectors. However, this is offset by a major increase in the producer and consumer surplus. These correlations help make Norwegian benefit more stable.

We assume that the carbon market will be used as an instrument to reduce greenhouse gas emissions leading up to 2030-50. However, the prices are currently very low, and it is possible that the entire market will be discontinued in favour of increased use of other instruments. If this happens, the average power prices will be lower in all of Europe, and the value of power trading will thus be reduced. At the same time, this could cause major differences between the short-term marginal costs of coal and gas power and thus greater price volatility in both Germany and the UK. This increases the congestion revenues and our analyses therefore show that, even with a carbon price of zero, the reduction in our basic estimates will be no more than 10-20%.

Our high and low scenarios indicate that the potential outcome for the cable benefit is large. At the same time, if we put together a combination of assumptions that either provide a very low or high benefit, this often indicates imbalance in the market. And the larger the imbalances, the greater the probability is of other market-based adaptations emerging to help re-establish this balance. Examples of these types of adaptations include:

- More consumption flexibility as a response to a development resulting in greater price volatility in Germany and the UK.
- Less new transmission capacity from Sweden vis-à-vis Poland and Germany as a response to a lower power surplus in the Nordic region and less price volatility on the Continent

These types of adaptations reduce the theoretical outcome for the benefit, and also make the extremes less probable than our more balanced basic estimate.

6 OTHER BENEFIT

6.1 Trade in balancing services

Trading automatic secondary reserves, also called aFRR or LFC, via the planned interconnectors is planned. Trade in such balancing services (= balance energy + reserves) creates potential higher revenue beyond day-ahead trading with energy. It is difficult to estimate this higher revenue as the current products for balancing services are not directly comparable, because the markets for these services are immature, and because the models to simulate these markets are not good enough. Our estimates are therefore largely based on empirical analyses, as well as knowledge of theoretical correlations. We have also used power market models.

The higher revenue is estimated at NOK 100 million/year, where the Norwegian share is NOK 50 million/year per cable, if we apply a dynamic model that continuously allocates up to 300 MW of the transmission capacity for trade in balancing services. The fact that the model is dynamic entails that, during some periods, 300 MW is used for balancing services trading, while less is used in other periods.

6.1.1 Empirical analyses

Based on historical data, analyses have been carried out to estimate activation revenues (revenues from trade in balancing energy) and reservation revenues (revenue from trade in reserved aFRR capacity). Theoretical activation revenue is calculated by multiplying relevant activation volumes by the relevant price difference for activation. Correspondingly, the reservation income is the reserved volume multiplied by the price difference for reservation.

Furthermore, concrete prices from the SK4 agreement were used. The SK4 agreement entails selling 100 MW aFRR to Energinet.dk over SK4 for a period of five years. On the Norwegian end, this volume is secured through agreements with two players. The agreed prices are fixed throughout the delivery period. Empirical analyses were also carried out to estimate activation revenues.

All analyses point in the direction of considerably higher revenue when trading in balancing services. The below figures show this.

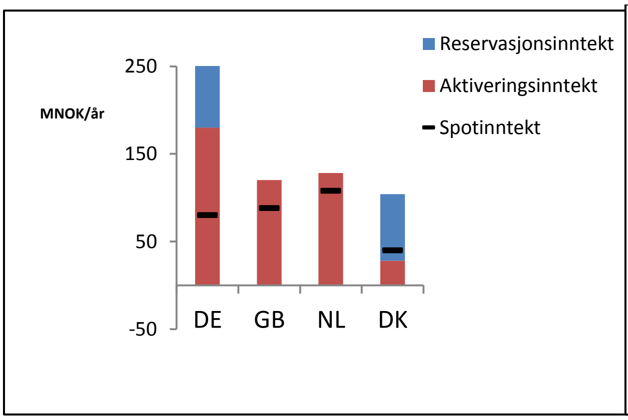

Figure 1: Estimated revenues from trade in balancing services and in the day-ahead market (100 MW) via interconnectors to Germany (DE), the UK (GB), the Netherlands (NL) and Denmark (DK) (Empirical analyses based on data from various periods in the years 2010-2012.)

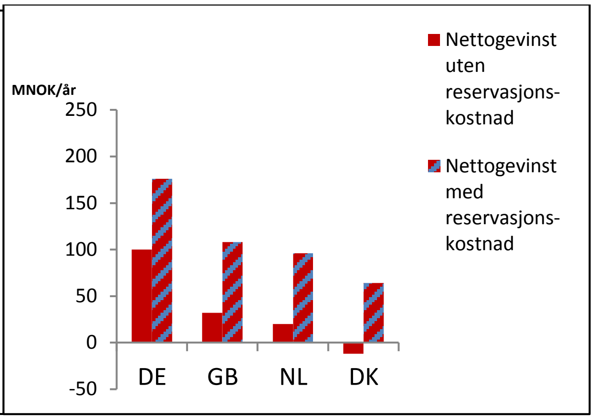

Figure 2: Estimated added value for trade in balancing services when German reservation revenue is used as an estimate for the UK and the Netherlands.

Figure 1 shows estimated trade revenues from allocation of 100 MW of transmission capacity to balancing services and day-ahead trading, respectively, to various countries. The revenue is split into activation revenue (red) and reservation revenue (blue). The black lines show estimated day-ahead revenue in the analysis periods for the same 100 MW. Reservation revenue was not calculated for the UK and the Netherlands as we did not have access to prices. The main reason for the Danish activation revenue being much lower than for the other countries is that the average activated volume is far smaller since it is a smaller market.

In Figure 2 the estimated day-ahead revenue is deducted to show the estimated total net benefit from trade in balancing services. Here the calculated German reservation revenue was added to the activation revenues for the UK and the Netherlands since we do not have reservation prices for these countries. The revenue from trade with Germany is thus our best estimate for the value for the UK and the Netherlands as well.

Based on results as shown in Figure 2, the added value for trade in balancing services with Germany and the UK is estimated at between NOK 100 and 150 million. The estimate applies to a static model where 100 MW are allocated to balancing services.

6.1.2 Model analyses

Statnett has carried out calculations with two energy and reserve market models:

- A model where the Nordic and northern European production system is represented with water reservoir, production and transmission connections. Various scenarios have been used to study the effect of varying water inflow. The model is a further development of Thema's spot market model.
- A principal model where we have a more detailed representation of the costs for a few producers distributed across a hydropower system and a thermal power system combined with wind power. The model is used for detailed analysis of short-term optimal allocation.

An important result from these studies is that optimal allocation between day-ahead and reserves varies significantly with the market situation on both ends of the cable, particularly with variation in water inflow on the Norwegian side both within one year and over several years. This confirms that dynamic allocation of capacity can be important to realise added value with combined use of transmission capacity for energy and balancing services.

Prices and trading revenues are only estimated by the first model and dynamic allocation in the first large model provides a benefit from trade in balancing services of 5-10% of total socioeconomic surplus for the entire interconnector. Measured in NOK, this is less than the results from the empirical analyses. One reason for this deviation is that the model has a simplified representation of the costs of keeping reserves. The model is also based on perfect information, and does not consider unforeseen incidents before and after the hour of operation that increase the balancing costs.

Due to considerable uncertainty and significant simplifications, we choose to place little emphasis on the quantitative results from these analyses.

6.1.3 Overall assessment and conclusion

There are several reasons why the results from the empirical analyses cannot be used as direct estimates for future value. Among other factors, the empirical data naturally does not detect future development in markets and prices. The below table shows our assessments of which factors will impact profitability:

Factors that contribute to increasing the	Factors that reduce the gains
• **Potential change of German market design for aFRR could result in increased reservation prices** The German market for aFRR is such that only the players whose reservation in the capacity market has been accepted can participate in the balance. This means that the players can offer a strategically low reservation price which they can recover from an activation price that is higher than the marginal cost. • **Introduction of a dynamic model where up to 300 MW can be allocated to trade in balancing services.** • More renewable energy results in more volatile energy prices, increased international reserve costs and increased volumes.	• **Norwegian reserve prices will increase.** • **A possible change of German market design for aFRR could result in lower activation prices.** • Norwegian prices for aFRR will be higher than the RK prices used as a basis for the analysis. • More cooperation between countries will reduce the needs (volumes).

Table 4: Factors that we consider significant for the future profitability of trade in balancing services. Bold factors are considered particularly important. Other factors are considered to pull in different directions, and, overall, have little significance.

In particular, the bold items in the above table are assumed to be significant for future profitability. Our assessment is that the factors that reduce the gains; Increase in Norwegian prices and lower German activation prices, dominate over the factors that increase the gains. This gives us reason to stay at the lower end of the interval for the added value that was outlined in the chapter on empirical analyses.

The other factors in the table (not bold) pull in different directions and it is our assessment that this, overall, does not give reason to change the estimate.

The added value of trade in balancing services with dynamic allocation of up to 300 MW is estimated conservatively at about NOK 100 million/year both with Germany and the UK. The estimate is based on an assessment of the SK4 agreement, empirical analyses, as well as assessments of future changes in market design and prices. The Norwegian added value is NOK 50 million/year.

6.2 Participation in capacity markets

Development of new, renewable power production facilities is moving quickly and the authorities in several countries are worried about whether the market will provide a sufficient volume with reliable capacity to maintain security of supply. To ensure capacity, several countries are planning to utilise so-called capacity mechanisms. The side effect of implementing such measures is that the price peaks during periods with low renewable production and high consumption would be reduced. This results in lower price volatility and thus lower expected revenue from trading via the interconnectors.

There are two main types of capacity mechanisms: «market-wide» capacity mechanisms and strategic reserve. There are several different variants under each of these two main categories.

A market-wide capacity mechanism entails a form of additional payment to *all* capacity necessary in a *strained power* situation. This production capacity also participates in the ordinary energy market.

A solution with strategic reserve entails that capacity that is kept outside the ordinary energy market is purchased, and it is only activated based on pre-determined criteria. With a strategic reserve, only the volume that is assumed to be missing in the ordinary energy market in a shortage situation and that is necessary in order to provide satisfactory security of supply is purchased.

Unlike a market-wide capacity mechanism, a strategic reserve does not provide additional investment signals for "normal" production capacity. How much a strategic reserve impacts the ordinary energy market depends in part on the activation criteria. A market-wide capacity mechanism will have a far greater impact on the energy market than a strategic reserve.

6.2.1 Design of capacity mechanisms in Germany

During the winter of 2012/2013, Germany had a strategic reserve. In November 2012, the Energy Act was amended so that the regulator BNetzA received the authority to order power station owners to postpone planned shutdowns of power stations if necessary out of consideration for security of supply. At the same time, a debate is on-going in Germany on the need for, and potential design of, a capacity mechanism in the long term. Statnett's analyses show that there will most likely not be enough production capacity in Germany in the long term without some form of capacity mechanism.

6.2.2 Design of capacity mechanisms in the UK

As part of the "Electricity Market Reform", the UK has made great strides in the work on introducing a capacity mechanism. The Department of Energy and Climate Change (DECC) is planning to introduce a market-wide capacity mechanism, and published an updated status for the design of the capacity mechanism in November 2012. They plan to publish further details in May 2013 and there is a possibility that the first capacity auction will be held in 2014.

In their memo from November 2012, DECC points to a number of reasons why international capacity should be able to participate in the capacity mechanism and that, in principle, this is desirable, assuming it can provide a corresponding contribution to the UK security of supply as to domestic production capacity. In March 2013, DECC published a proposal for how international production capacity can be included in the capacity mechanism. The proposal was submitted to the "Capacity Market Expert Group». DECC also states that they will discuss with the EU Commission how international production capacity can participate in the UK capacity mechanism.

6.2.3 Norwegian production capacity should be incentivised if a capacity mechanism is introduced

Cables from Norway will give Germany and the UK access to the flexible Norwegian hydropower system, and will provide a considerable contribution to the countries' security of supply. This is illustrated in the below figure, which shows the flow between Norway and the Netherlands in the NorNed cable. In the figure, all hours since the start-up in 2008 are sorted according to Dutch prices[4]. The red area shows average export from the Netherlands, while the blue area shows import to the Netherlands. The figure shows that, when there are high prices in the Netherlands there is maximum import to the Netherlands from Norway, which indicates that the Netherlands import when they are short of capacity.

[4] Hours of failed market coupling have been removed from the data basis.

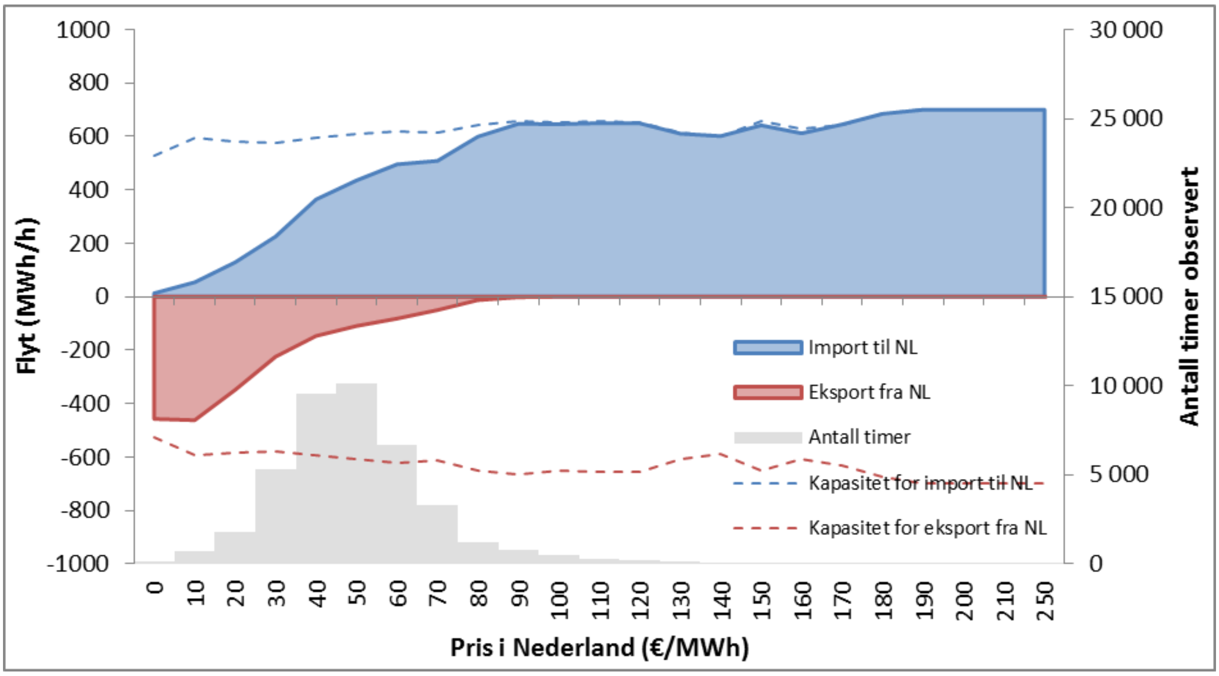

Figure 3: Average market flow in the NorNed cable during the period 2008-2012 (first y axis) as a function of Dutch power prices sorting in ascending order (x axis). The blue area shows import to the Netherlands, while the red shows export from the Netherlands. The blue and red dotted lines show how much transmission capacity was made available to the day-ahead market. The grey histogram shows how many hours (second y axis) the price has reached the various levels during the analysis period. The market connection algorithm malfunctioned one day in 2011. Data from this date have been removed from the data basis.

6.2.4 Expected revenues in capacity markets

Method

In cooperation with Pöyry, we have calculated the price we can expect in the capacity markets, in order to determine what revenues a cable could achieve through participation in such markets. Pöyry has developed a model that, among other things, can be used to analyse capacity markets. This was also used when Pöyry worked on capacity markets for the UK authorities. The model has concrete assumptions regarding:

- How the capacity market is designed, e.g. related to how much capacity should be available in the market
- The size of the payment thermal power station owners need to either invest in new power stations or keep power stations that are not profitable, based on the prices in the day-ahead market
- Which players (production, consumption and grid) can participate in the capacity market, and how they are rewarded for their reliability

Our calculations indicate that a maximum price in the capacity market is around EUR 60-80 million/year, which is about the cost of building a new peak load facility. We do not anticipate that the price will be set at this level each year, as the price will also be set by new power stations that earn money both in the capacity and day-ahead markets, or from existing power stations.

Pöyry has estimated that the auction price in the British market could be, on average, approx. GBP 20 000 – 25 000/MW/year[5] between 2020 and 2030. For a 1400 MW cable, the potential revenue is then EUR 34 – 42

[5] This is real 2012 GBP.

million annually. [6]. We use EUR 30 million. annually as an estimate for both interconnectors. This e.g. takes into account the uncertainty related to how participation in capacity markets will interact with trade in balancing services.

Pöyry argues that a German capacity price could be somewhat lower because the country has stronger connections to its neighbouring countries than the UK, and thus has a lower need for domestic capacity. However, our assessment is that there are so many uncertain factors, e.g. related to the design of capacity markets, that it is not expedient to differentiate between estimated capacity prices in the two markets at the current date. Still, we have assumed that a market-wide capacity market in Germany will not be in place until 2020.

[6] This assumes an exchange rate of 1.2 EUR/GBP

7 Cost estimates

This chapter presents cost estimates for the cables, associated land-based facilities and relevant domestic grid reinforcements. Other relevant costs associated with the interconnectors are also presented here.

This chapter provides all amounts in 2012 NOK.

7.1 Investment costs

7.1.1 Investment costs for subsea cables, land cables, power lines and land-based facilities

the socioeconomic analysis must, to the extent possible, be based on unbiased estimates. This means that the estimates for investment costs must include an addition for uncertainty. The addition is calculated based on an uncertainty analysis of the cost estimates for a substation, subsea cable, onshore facility and power line in line with Statnett's procedures for cost estimation.

The cost estimate is based on experience from previous projects in Statnett, e.g. from NorNed and SK4, and relevant assumptions for the future. Both projects are still in the development phase, and the investment costs are therefore not yet tied up in fixed price contracts. Uncertainty associated with the investment costs is assessed to be within an interval of +/- 40% with a confidence interval of 80%.

Numbers in million NOK (2012 NOK)	Germany	The UK
Expected investment cost (incl. uncertainty mark-up)	**6 300**	**6 850**

Table 5: Expected investment cost including uncertainty mark-up (in actual 2012 NOK). Building loan interest is not included. Norwegian share.

Building loan interest has not been included in the expected investment cost since it, in line with normal practice, is taken into consideration in the discount rate. Accrued costs to date are not relevant in the socioeconomic profitability assessment. We would like to emphasise that these investment costs are in actual Norwegian kroner and without building loan interest. In the project implementation the figures will be based on nominal sizes including building loan interest.

7.1.2 Investment costs for domestic grid reinforcements

New interconnectors could result in increased costs in the domestic grid. These are primarily costs associated with the need for developing new capacity, and in certain cases associated with the need for available capacity to be used up so that other use of the grid can be restricted.

We use the following principles as a basis for allocation of costs for the interconnectors:

- Accrued costs are not included
- If cables displace other use, relevant lost benefit is included as a cost
- No cost is allocated if the measure is socioeconomically profitable without the cable interconnectors
- For investments that are triggered, and that are not socioeconomically profitable by themselves, the cost, less potential increase in other benefit (net cost) is attributed to the cables

The total net cost that can be allocated to the two planned interconnectors is NOK 3.5 billion (see Appendix 3). Of this NOK 2 billion is allocated to the Germany cable and NOK 1.5 billion to the UK cable. This assumes the Germany cable is built first.

It is assumed that domestic grid reinforcements will mostly be in place for commissioning and have a construction time of three years with a regular cost mark-up each year. These costs are not shared with a partner.

7.2 Operating costs

7.2.1 Operating and maintenance costs

Statnett has calculated annual operating and maintenance costs with a basis in a planned maintenance programme and an insurance scheme corresponding to the one we currently have for corresponding interconnectors. Since the insurance cost is included, we do not take into account future repair costs beyond what is covered by the insurance.

In principle, reinvestments in components with shorter lifespans than the analysis horizon should be included as part of the socioeconomic analysis. In the relevant projects, there are few components with an expected lifespan of less than 40 years. The identified factors are mainly related to control systems and associated IT solutions connected to the substation facilities

Based on experience, the control system is replaced after about 20 years at a cost of NOK 40 million per substation. For practical reasons, the cost has been included in the estimate for operating and maintenance costs.

Annual (million 2012 NOK)	Germany		The UK	
DV	Years 1-25	Years 26-40	Years 1-25	Years 26-40
	29	25	33	28
Insurance	10		15	
Reinvestment after 20 years	80		80	

Table 6: Estimated annual operating and maintenance costs (OM) and insurance costs for the two interconnectors. Expected costs for reinvestment after 20 years.

The analyses assume that the Norwegian share will constitute half of the costs in the table. Our share of the annual operating and maintenance costs, including insurance, will constitute just under NOK 20 million for Germany and about NOK 20 million for the UK.

7.2.2 Transit costs

Pursuant to EU Commission Regulation 838/2010, a joint European system (Inter TSO Compensation, ITC) has been established to ensure that countries are compensated for both loss costs and capital expenditure related to transit. This compensation is paid by those who pay tariffs in the countries with so-called net power trading, i.e. countries with net purchase or sale measured on an hourly basis. The purpose is to provide a reasonable distribution of tariff costs between domestic and international grid users.

Compensation for loss is based on load flow analyses and energy costs. Historically, the total amount for loss compensation has been EUR 100-150 million/year. The total compensation for capital expenditure is set at EUR 100 million/year.

The European ITC settlement has resulted in international trading costs for Norway. This is expected to continue in the future, because the flexibility in the Norwegian power system means that we function as a battery for the surrounding power systems. This means that we will often have synchronous flow in all our interconnectors, and therefore that we have major net power trading.

The ITC payment is a socioeconomic cost associated with the cable projects and should therefore be included in the profitability assessment of the project. We thus need to estimate the scope of the effect the planned interconnectors will have for our ITC cost. To estimate the annual ITC cost we have used two alternative approaches:

Pro rata aggregate/increase. We have used the annual ITC cost/payment and annual gross flow for the two countries being connected as our basis. Data from 2010 up to and including September 2012 has been used. We have calculated a 'unit ITC value' of flow by dividing ITC payment by gross flow. We then multiplied this by the expected gross flow on the new cable. In other words, we have calculated the impact of the cable assuming that power trading on this will have the same cost or revenue per MWh of flow as existing interconnectors.

Empirical flow analysis. We have used prices and actual power flow as a basis in 2012. Based on prices, we have assumed what the flow in the new interconnectors would be, and in turn assessed what the ITC consequence would be for the two countries.

Changes in the energy mix or new interconnectors will result in a different flow pattern than what has been observed historically:

- In Germany, more wind and solar energy is expected in the future. It is reasonable to assume that this will result in more synchronous power trading with other countries and less transit
- For the UK, it is expected that more wind power will result in more synchronous power trading with other countries, while more cables to other countries results in more transit and less net power trading with other countries
- More cables results in somewhat more transit through Norway
- Increased trading in Europe contributes to reducing all sizes.

There were no assessments of increased or reduced total compensation for capital expenditure.

Our estimate is that a Germany cable will increase Norway's costs by EUR 4 million/year, and increase Germany's revenues by EUR 2 million/year. Furthermore, we estimate that an interconnector to the UK will increase Norway's ITC costs by EUR 4 million/year and that the UK's ITC costs will also increase.

Sharing costs and revenues

In a letter to Statnett dated 11 June 2012, Bundesministerium für Wirtschaft und Technologie signalled that the net impact associated with the European transit settlement, caused by flow in the planned Germany cable, can be split between Germany and Norway. The project has a good dialogue with the German regulator regarding the details of such a split.

Based on our estimates, the signed agreement to distribute the net impact of the cable on the ITC settlement equally, will reduce Norway's cost by EUR 3 million/year. This means that Norway's net ITC cost will increase by EUR 1 million/year as a result of establishing an interconnector to Germany.

The UK and Norway have not agreed to share ITC costs and revenues as a result of establishment of a new interconnector between the countries.

7.2.3 System operation costs

New international trading capacity will have an impact on production, consumption and transmission in the Norwegian grid, which will have consequences for Statnett's system operation costs. We anticipate these to increase as a result of increased international trading.

The biggest change is related to the need for automatic reserves. The need for automatic reserves is estimated at about 140 MW per cable (10% of transmission capacity) with an associated cost of about NOK 60-80 million per year. There are also some increased costs for increasing and decreasing regulation, as well as reactive power.

Annual (million 2012 NOK)	Germany	The UK
Automatic reserves	60-80	60-80
Increase in generation	20-30	20-30
Decrease in generation	20	20
Reactive power	5	10
Total costs	**120**	**120**

Table 7: Overview of expected system operation costs associated with increasing trading capacity by 2800 MW. In the socioeconomic analyses it is assumed that annual system operation costs will increase by approx. NOK 120 million for each of the two planned interconnectors. These costs are not shared with a partner.

7.2.4 Transmission loss in the Norwegian grid

When the two cables become operational, the transmission loss in the Norwegian grid will increase. The power price increase caused by the cables will contribute to increasing the costs associated with covering the existing transmission loss in the Norwegian grid. The transmission loss in the actual cables has been taken into consideration when calculating the congestion revenues. Here it is also assumed that loss in the cables is taken into consideration implicitly in the market algorithm.

The estimated annual value of the increased loss costs in the Norwegian grid will be EUR 12 million/NOK 97 million for the Germany cable and EUR 7 million/NOK 56 million for the UK cable. The analyses show that the average cost per GWh transmission loss is higher for the UK than for Germany. The reason is that the UK cable increases the power prices which, in turn, increase the costs of the transmission loss caused by the Germany cable.

Annual (million 2012 NOK)	Germany	The UK
Volume (GWh)	240	110
Cost	97	56

Table 8: Estimated annual value of increased loss costs in the Norwegian grid. The conversion from EUR to NOK is based on an exchange rate of 8.1 NOK/EUR. The costs are not shared with an international partner.

7.2.5 Tariffs

Interconnectors are not considered a client that must pay a grid tariff in Norway, Germany or the UK. If tariffs are introduced that are directly paid by interconnectors, the party in the country in which the tariff is introduced is responsible for paying the entire tariff amount. The parties are thus only responsible for paying tariffs in their own country. This solution helps reduce Statnett's risk associated with changes in regulatory regimes in Germany and the UK.

Introduction of tariffs for interconnectors would also conflict with the EU's ban on border tariffs.

7.3 Financial consequences of temporary limitations in trading capacity

The revenues from the new transmission interconnectors could be reduced due to the fact that not all of a cable's transmission capacity can be made available for day-ahead trading in all operating situations. Adaptations of the transmission capacity pursuant to the condition in the domestic grids both in Norway and with our trade partners must be expected. The financial consequences of this are strictly speaking not a cost, but a reduction of the calculated socioeconomic benefit of a cable. We have chosen to include this here instead of in the chapter on benefit from day-ahead trading, as the largest limitations are only temporary. The reduction in revenue must be seen in context with the value of operational flexibility and, overall, this could thus still be positive for Norwegian society.

Grid reinforcements in Norway are necessary for both planned cable interconnectors. A detailed description of the planned grid reinforcements in Norway and in partner countries is provided in Appendix 3. The projects in the Western Corridor are most relevant. Delays in relation to the scheduled times of completion for the various parts of the Western Corridor could cause restrictions in trading capacity on both interconnectors during the first years of operation. Our simulations, which assume that the rest of the grid is intact, indicate relatively minor net socioeconomic consequences of this. The calculations assume that the Sauda – Lyse section (Step 2 in the Western Corridor) will not be complete until the beginning of 2020. This has an overall negative effect on the revenues corresponding to approx. EUR 7 million. In addition, the simulations indicate that increased power flow on the cables can create a bottleneck north of Sauda.

Local, regional and national grid conditions in Germany could result in reduced trading capacity for the Germany cable. The financial consequence of limited trading capacity will depend on the frequency and duration of the restrictions and the price difference between the markets in the relevant time period. Most restrictions are expected to take place with export from Norway to Germany during the peak load hours on weekdays. We assume that this will have a negative annual effect corresponding to 5-10% of the congestion revenues, and that the restrictions will be gradually reduced until all necessary measures are in place. Specifically, we are reducing the congestion revenues by the following rates:

- 2018: -7%
- 2019: -7%
- 2020: -5%
- 2021: -5%
- 2022: -3%

Decreasing generation in the interconnector will likely have to take place in return for financial compensation. This is not included in the socioeconomic analysis, as the terms for a potential decrease in generation are not known at this time.

Significant temporary reductions in trading capacity as a result of limitations in the domestic grid are not expected for the UK cable.

8 ROBUSTNESS AND SENSITIVITIES

The cost and benefit estimates will always be associated with uncertainty. Uncertainty is often considered to be somewhat negative, and something to be avoided. It is important to note that uncertainty also provides possibilities. The term covers both estimate uncertainty and incident uncertainty. Estimate uncertainty is related to whether the level of our estimates is reasonably accurate, while incident uncertainty is whether or not something occurs, and the consequence of this. In addition to the risk and possibilities of implementing measures, there is also a risk from not implementing these measures. The latter will not be described further.

Uncertainty can be processed in multiple ways in a socioeconomic analysis. The most common involves using a risk-adjusted discount rate which reflects systematic risk. We also do this for this analysis. In addition, we approach uncertainty in the following manner:

- Description of all assumptions that form the basis for estimation (see previous chapters)
- Description of individual deviations from the assumptions
- Description of risk (downside)
- Description of possibilities (upside)

The analysis shows that there are many drivers for uncertainty and that the financial consequences could be considerable. The potential outcome for the energy trading revenues is particularly large. The trade solutions and the applied discount rate are also vastly significant for socioeconomic profitability. An overall assessment indicates that the socioeconomic profitability of both projects appears to be very positive for Norway.

There will most likely be uncertainties that we are not yet aware of.

The uncertainty review focuses on alternatives 1 and 2, as described at the beginning of Chapter 3.

8.1 Potential outcome of expected benefit from day-ahead trading

To get a general overview of what the different uncertainties entail for the overall trading benefit, we have prepared a low and high scenario for both 2020 and 2030. Here we changed certain assumptions in the basic data sets that have considerably high uncertainty and that we know have a major impact on trading benefits. The objective has been to change multiple assumptions simultaneously that pull the benefit in a positive or negative direction, respectively.   However, we have been restrictive in relation to how much we pull. The goal has not been to illustrate the extremes, but rather to outline a possible outcome that could last for much of the cables' lifespans.

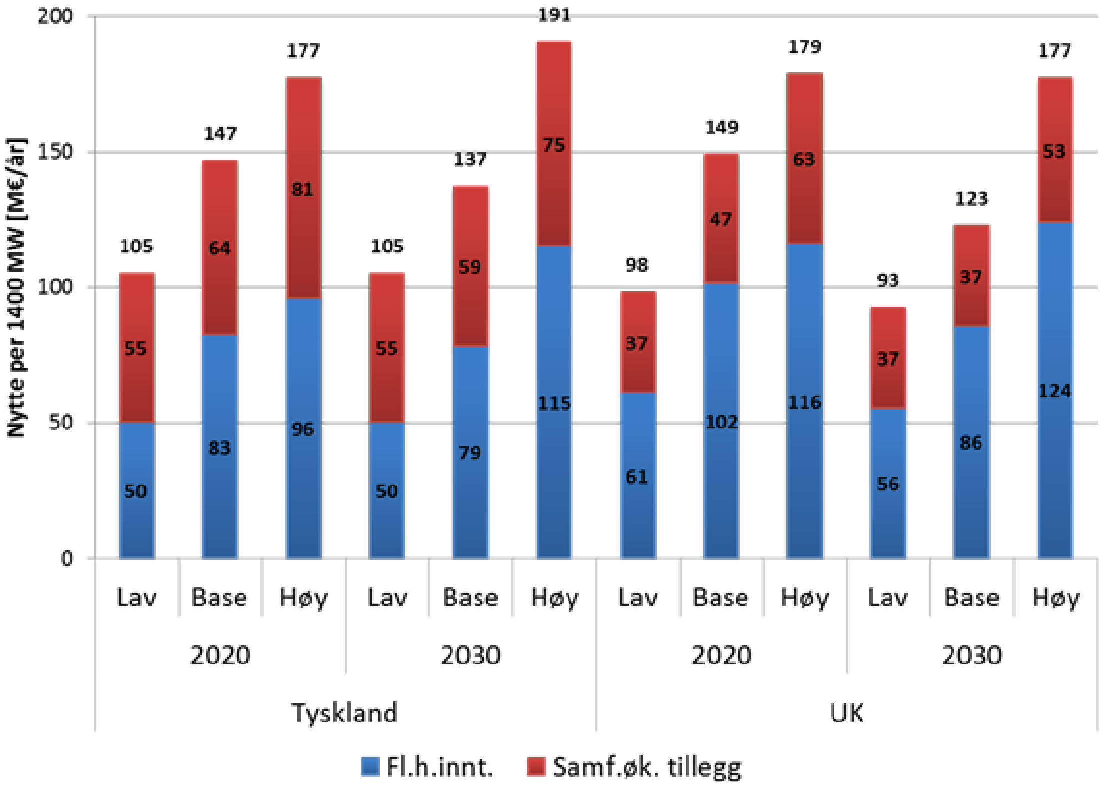

Figure 4: Basic estimate and outcome illustrated with low and high scenarios for 2020 and 2030. (Fl.h.innt. = congestion revenue. Samf.øk. tillegg = "socioeconomic supplement")

As shown in the above figure, with our assumptions, there is a difference in annual benefit between a high and low scenario of EUR 70 to 90 million per 1400 MW cable. We believe this provides a realistic picture of the uncertainty. At the same time, it is important to know that it is possible to put together other combinations of assumptions that both provide a corresponding and larger potential outcome.

Another point is that high and low scenarios are an approach to expected benefit with another market development. As with the basic estimates, fluctuations in weather, fuel prices and consumption could result in major deviations from this.

8.1.1 Low scenario: Lower power surplus in the Nordic region - less consumption and less renewables in the rest of Europe

Economic downturn will continue until 2020

The mind-set behind our low scenario for 2020 is that the economic downturn will continue in Europe. This results in less consumption and less development of renewable production here. However, we have chosen to keep the Nordic system unchanged from the basic data set. We do not consider it probable that the surplus in the Nordic region will be reduced if the economic downturn continues because much of the production growth is already in the works, while the growth in consumption is positively correlated with the financial growth in Europe. Specifically, we have adjusted the following factors (all figures are referenced with our assumptions in the basis for 2020 and 2030):

- Consumption is decreased by 5 per cent (outside the Nordic region)
- Development of new renewables is reduced by20 per cent (outside the Nordic region)
- The gas and carbon prices have been reduced to EUR 7/MWh and EUR 7/tonnes, respectively. This corresponds to a reduction of EUR 15/MWh in marginal costs for a typical gas fired power station. It is

just as important for the benefit that we achieve more similar marginal costs in coal and gas fired power stations.
- Better capacity margin (outside the Nordic region)

More cost-efficient reduction of greenhouse gas emissions towards 2030

When we get to 2030 be believe it will be unrealistic to assume that there will still be an economic downturn. We still have lower consumption and less renewables than in the basis, but this now comes as a consequence of more energy efficiency. This is a more cost-efficient alternative for reducing emissions, and thus not quite feasible. On the Nordic side we have also reduced the Nordic power surplus.

- Consumption and renewable power production on the Continent is reduced by 12 and 20 per cent, respectively. This corresponds to a decline of 200 TWh in consumption and 140 TWh in new renewable production
- The surplus in the Nordic region was reduced by removing 11 TWh in Swedish nuclear power production and 3 TWh in small-scale power in Norway. This results in a Nordic surplus of 15 – 20 TWh
- The capacity margin in all countries outside the Nordic region has been increased
- The mark-up in the $_{\text{carbon}}$ price in the UK has been removed so the carbon prices are the same across Europe
- The fuel prices are otherwise the same as in the basis for 2030
- Sweden is not building any more cables after NorBalt, as a result of lower price volatility on the Continent and a lower surplus in Sweden/the Nordic region

The congestion revenues primarily decrease in the low scenario

The distribution of congestion revenue and "socioeconomic supplement» in Figure 4 shows that the congestion revenues are the primary reason for the decreased total benefit in our low scenario. There are mainly two reasons for this:

1. Many of the factors we adjusted contribute to lower price volatility on the Continent. This reduces the congestion revenue but has little impact on the PS (producer surplus)/CS (consumer surplus) benefit
2. fluctuations and a large share of regulated hydropower result in the PS/CS benefit remaining at a high level, even though there is a lower Nordic surplus and a reduced price level with our trade partners

The reduction in congestion revenue from existing cables also becomes smaller when the price volatility declines with our trade partners. The same applies if the PS/CS benefit becomes lower, as is the case in 2030 where we reduced the surplus in the power balance in both Norway and the rest of the Nordic region. Both of these correlations cause the total benefit apart from the congestion revenues to vary less between a high and low scenario.

The price volatility declines in Germany and the UK

Most adjustments for 2020 and 2030 pull in the direction of lower price volatility in Germany and the UK. However, if one does not predict a technological revolution within storage of energy and/or substantial consumption flexibility, there is a limit to how low the price volatility in Europe can become, even with the introduction of capacity markets. In addition, the incentives for developing more flexibility are low when volatility is low, because price volatility is in fact the payment for this. We therefore have somewhat less consumption flexibility in our low scenario for 2030 than in the basis.

8.1.2 High scenario: Higher power surplus in the Nordic region - increased fuel prices

We have adjusted a selection of factors that increase the benefit, and that could conceivably occur at the same time. The most important changes are a larger Nordic power surplus, higher fuel prices and more price volatility on the Continent and in the UK.

Specifically, we have increased the Nordic power surplus to about 35 TWh in both 2020 and 2030. Of the 8-10 TWh of additional surplus, approx. 3-5 TWh will be in Norway. This results in a total surplus in Norway of approx. 15 TWh in 2020 and 12 TWh in 2030.

In 2020, the marginal costs were increased by 20% in all coal and gas fired power stations. The carbon mark-up in EMR in the UK has increased from EUR 6/tonne to EUR 8/tonne. Otherwise, 2020 is the same as the basis for 2020 as regards capacity composition and consumption on the Continent

In 2030, we removed the consumption flexibility on the Continent which we included in the basis. Together with a tighter capacity margin, this results in higher price peaks and fewer zero prices. Both coal and gas prices have been increased by 20 per cent, while the carbon prices remain unchanged. The mark-up in the UK is the same as in the basis.

Both higher congestion revenues and greater PS/CS gains increase the benefit

In 2020, the distribution between increase in congestion revenue and "Socioeconomic supplement" is relatively even». More price volatility in Germany and the UK, as well as a larger power surplus in the Nordic region results in greater congestion revenues. The combination of a larger surplus and higher fuel prices increases the PS/CS gains. The reason why what we call the socioeconomic supplement does not increase more, is that there is a simultaneous loss in existing interconnectors.

When we get to 2030, the impact on the PS/CS gains is somewhat weaker, due to a smaller surplus in Norway and more cables from Sweden. On the other hand, the price structure on the Continent is significantly higher, which results in a corresponding increase in congestion revenues.

It is worth noting that the benefit in this scenario is so high that there will most likely be more cables from the Nordic region than what we have predicted. This will reduce the trading benefits, and one could therefore argue that the level is not sustainable in the long term. At the same time, building cables takes both time and resources. Trading benefits at this level could therefore last for long periods. In addition, various market shocks could make the benefit very high for short periods so the average also becomes very high. With the major changes we expect/do not expect to occur both in the European and Nordic power systems in the next 10-30 years, the possibility of imbalances in the market, and thus high trading benefits, also increases.

Greater price volatility in Germany and the UK

In 2020, there is a large difference between the three scenarios, which is caused by different assumptions regarding fuel prices. In 2030, the price level is about equal in the low scenario and in the basic scenario because the fuel prices are the same. They are increased by 20 per cent in the high scenario. The price volatility in the high scenario mainly increases due to higher prices during peak load. This is particularly evident in 2030, where the night-time prices are about equal in all three scenarios, but the peak load periods are significantly higher in the high scenario. Here it is important to clarify that our high scenario is no key to what could potentially drive a development with higher benefit than what we have in our basic estimates. For example, a development with more renewables and a less tight capacity margin will result in about equal gains, but with lower price peaks and more hours approaching zero.

8.1.3 Major benefit despite uncertainty

The potential outcome for the size of the future benefit of building cables to Germany and the UK is considerable. At the same time, our analyses show that the benefit is relatively stable and robust. We will briefly review a few key arguments for this.

Increased trading capacity results in high benefit in a broad spectrum of future development paths

The cables will allow for trading both ways, either in the form of nearly continuous flow one way or with frequent changes in the flow direction. This flexibility means that the cables can contribute to increased use of resources, thus creating high socioeconomic gains, in a broad spectrum of future development paths.

The present situation is that the hourly price differences between Norway and Germany and the UK, respectively, are considerable and Norway and Sweden have a lot of regulated hydropower that no doubt constitutes a major and unused potential for moving the production. The cables would therefore generate major congestion revenue if they were ready to be used now[7]. The current system also has a large share of unregulated production during the summer months and hydrological fluctuations have resulted in several periods with extremely low summer prices in recent years. With the current system, we would thus receive a major benefit from the cables in the form of increased producer and consumer surplus.

In our estimates there is an additional benefit caused by expectations of a major power surplus and substantial volumes of unregulated production. However, this does not mean that the future benefit depends on this becoming the actual situation based on the cables' lifespans. For example, should there be a situation with a shortfall, this would also create a very high benefit, but then largely through cheaper import during dry years.

Our analysis demonstrates that the benefit is robust in a large number of alternative development paths for the European power system.

Future market development is uncertain, but main characteristics are clear

Despite the uncertainty associated with the power systems in North-Western Europe, the main characteristics remain relatively clear.

- Europe is heading towards a restructuring of the power system with a significantly higher percentage of renewable production and lower greenhouse gas emissions. Germany and the UK are well on their way and have established concrete political goals and measures
- There will be a sufficient capacity margin in the UK and on the Continent, caused by either pressure from national authorities or the EU
- The Nordic region will have a larger power surplus, and there will be more unregulated production in Norway and Sweden through the electricity certificate market
- The transmission capacity out of the Nordic market will be greater from Sweden, Finland and Denmark, and trade between Finland and Russia will be flexible

This limits the scenario uncertainty of the estimates.

More short-term price volatility in Norway is likely to have a moderate effect on cable benefit

There is little doubt that the short-term price volatility in Norway will increase when the cables to Germany and the UK enter operation. This reduces the congestion revenues and explains why the marginal benefit of new transmission capacity is declining. Due to model simplifications, we cannot fully see these correlations in our simulations, and it therefore constitutes an uncertainty in our estimates. Overall, we still believe the effect on total Norwegian benefit of increased short-term price volatility in Norway will be moderate for the two cables. We can explain this by the following:

- There is still a major potential for reallocating the production from regulated hydropower, which alleviates the increased impact from the German and UK price structure
- We will have a larger producer and consumer surplus when the short-term price volatility increases, and we will keep this ourselves

Overall, this is likely to compensate for much of the reduction in Norway's share of the congestion revenue. At the same time, this means that we are most likely exaggerating the congestion revenue and underestimating the change in the producer and consumer surplus in our estimates.

A larger increase in trading capacity than what we use as a basis is no major threat

More interconnectors out of the Nordic area than we have assumed will reduce the benefit of the Germany and UK cables. However, we still do not consider this to be a major uncertainty in our estimates.

Firstly, it takes a long time to decide on and engineer new interconnectors, and with the exception of North Connect, we are not aware of any concrete plans beyond what we have already used as a basis for our

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[7] Historical price differences indicate that the congestion revenues would beEUR 80-90 million per cable over the last ten years, on average.

estimates. Sweden recently published its perspective plan which includes the possibility of a new interconnector to Germany. However, it is not scheduled to be ready until around 2025, and will likely correspond to about the same capacity increase as we have already assumed in our estimate for 2030. With a normal development time of at least 10 years, it is therefore unlikely that there will be any entirely new projects until 2025 at the earliest, seven years after the Germany cable is scheduled to become operational.

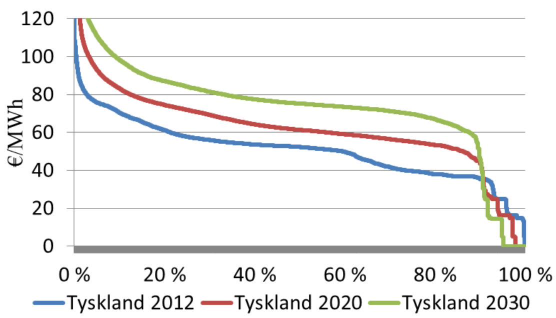
Secondly, we can also expect that more cables assume that they have a positive socioeconomic cost/benefit, since this is a requirement for obtaining a licence. If so, we will probably be in a situation where the gains from the Germany and UK cables are also high. An exception from this is if the investment costs are significantly lower or if the cables are built by hydropower producers. The latter could benefit greatly from building cables, even with a weak socioeconomic cost-benefit, since the value increase of own hydropower production is very high in many cases. However, we believe that the licence authorities will stop new projects with negative socioeconomic profitability.

Thirdly, more interconnectors will most likely require investments in more output in the hydropower system. In this case, it will halt the declining benefit and thus protect the gains from the first cables.

The price volatility in Germany and the UK is expected to remain stable, even with more renewables

The future price volatility in Germany and the UK will still be considerably higher than in Norway. And, as shown by the duration curves in Figure 5 the price scenario in our simulations for 2020 and 2030 is very similar to the current situation, apart from the difference in price level. This is despite a drastic growth in the percentage of renewable production during the same period.

The reason there are no major changes in price volatility is that thermal power stations will still determine the price most of the time, even in 2030. This means that marginal costs and start and stop costs for thermal power stations are still the most important price driver on the Continent. Start-stop costs could have even greater significance because production that cannot be regulated means that thermal power stations have to be started and stopped more frequently to balance out these variations. More renewables do not generate greater volatility, but as we can see in the curves, there is very little growth in the percentage of hours with very low power prices. In 2030, the prices are lower than EUR 20/MWh for less than 10 per cent of the time, both in Germany and in the UK.



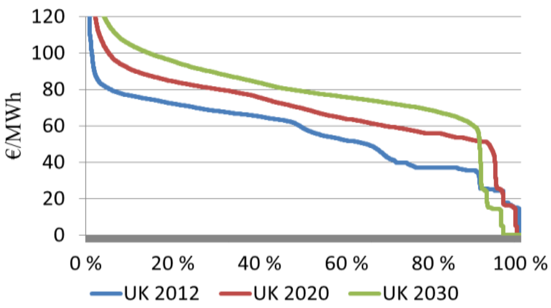


Figure 5: Duration curves for simulated price for Germany and the UK in 2012, 2020 and 2030

We have carried out a number of sensitivity analyses where we e.g. changed the percentage of renewable production in both Germany and the UK. What we saw was that we need to increase the renewables percentage substantially in order to create significant changes in price volatility. This is firstly because major volumes are needed before the consumption can be covered by renewable and nuclear power alone. Considerable transmission capacity internally and vis-à-vis other countries[8] is also an important reason for why the percentage of hours with prices down to nil is relatively low.

[8] With our assumptions the total transmission capacity from Germany would be 26 000 MW in 2030

The introduction of capacity mechanisms is another important reason why growth in renewable production does not cause such major changes in price volatility. This ensures a better capacity margin than if thermal power stations would receive all of their earnings from the day-ahead and regulating power markets alone. And with a better capacity margin, we have fewer and lower price peaks during periods with high consumption and low renewable production.

Continued growth in renewables after 2030 can also cause increased volatility, but then more increased consumption flexibility is also more likely. This helps stabilise the volatility, and thus the benefit of our cables, over time.

Different factors offset each other and create more stable benefit

The many factors that impact benefit can and will in many cases offset each other. Overall, this has a stabilising effect on the total Norwegian benefit.

Congestion revenue and producer surplus (PS)/consumer surplus (CS) are partially negatively correlated

The producer and consumer surplus, congestion revenues and loss in existing interconnectors are also closely linked through the cables' effect on Norwegian power prices. During periods where price effects are small, nearly all of the benefit will be in the form of congestion revenue. The total producer and consumer surplus, and congestion revenues from other interconnectors, remain nearly unchanged. However, in periods with major price effects, congestion revenues will be lower, and we will experience considerable loss from existing interconnectors. However, this is offset by a major increase in the producer and consumer surplus. These correlations help make Norwegian benefit more stable.

The major increase in the total producer and consumer surplus also causes the risk to be distributed across several different factors. Thus, multiple factors need to pull in the same positive or negative direction if they are to have a major effect on the total Norwegian benefit.

Long-term market adaptations reduce potential outcomes

It is possible to link preconditions that create both higher and lower benefit than what we have outlined in our more conservative potential outcome. At the same time, if we turn to a combination of preconditions that either create a very low or high benefit, this often reflects a system that is out of its natural balance. The more out of balance the system is, the greater the probability of adaptations taking place to re-establish the balance. Examples of these types of adaptations include:

- More consumption flexibility with continued growth in the renewables percentage in Germany and the UK, beyond what we have used as a basis for 2030. This lessens the increase in price volatility with more renewables
- Less new transmission capacity from Sweden to Poland and Germany if we get to 2020 and then find ourselves in the low benefit scenario

These types of adaptations help reduce the theoretical outcomes and thus make our benefit estimates more robust.

Independence between the benefit drivers creates more stable estimates

Many of the benefit drivers are independent of each other. *The probability* of several factors pulling in the same direction is therefore lower than if they had been correlated. For example, there is little correlation between future fuel prices and the size of the Nordic power surplus. This helps reduce the probability of extreme outages thus making the estimates more stable.

8.1.4 Socioeconomic profitability in low and high scenarios

Based on applicable cost estimates for the Germany cable, EUR 86 million/NOK 700 million is necessary in annual utility values to achieve an internal rate of return that is equal to the required rate of return of 4%. In the low scenario, the total of annual changes in congestion revenues and PS/CS is expected to be, on average, approx. NOK 860 million. The estimated internal rate of return will then be about 8% and the net present value is NOK 5 500 million if other assumptions regarding the cost and revenue remain constant. An overall assessment indicates that the project is robust vis-à-vis the scenario with low revenues. In the scenario with high revenues, the internal rate of return will be about 14% with NOK 16 400 million in net present value.

For the UK cable, EUR 86 million/NOK 700 million is necessary in annual total utility values to achieve an internal rate of return that is equal to the return requirement of 4%. In the low scenario, the total of annual changes in congestion revenues and PS/CS is expected to be, on average, just under NOK 770 million. Annual higher revenue for Norway from trade in reserves is expected to be about NOK 50 million and capacity mechanisms contribute NOK 120 million annually. Total annual gains are then about NOK 940 million, and the calculated internal rate of return is about 6% and the net present value is NOK 3 850 million if other assumptions remain constant. An overall assessment indicates that the project is robust vis-à-vis the scenario with low revenues. In the scenario with high revenues, the internal rate of return will be about 13% with NOK 14 300 million in net present value.

8.2 Uncertainty associated with temporary restriction of trading capacity

On the Norwegian side, it is uncertain whether the capacity of the new interconnectors can be fully utilised from start-up due to the uncertainty associated with the progress in the projects in the Western Corridor. This issue is temporary in nature in the sense that the planned measures are expected to be sufficient in order to fully utilise the trading capacity when they are implemented.

The scope and complexity associated with the work in the Western Corridor is substantial. This results in implementation risk.

- Step 1 of the Western Corridor is scheduled to be complete by the end of 2018
- Upgrade of the voltage on Lyse-Sauda (Step 2) will be completed in 2019
- The 420 kV Ertsmyra-Solhom-Arendal (Step 3) will be completed in 2020.

Delayed completion of Step 1 will result in both cables being run with restricted capacity for a longer period than what has been used as a basis. The UK cable is scheduled to be complete in December 2020, so the delay would have to be significant in order to impact this. If, for example, none of the upgrades of Lyse- Duge and Solhom-Tonstad to three-bundle conductors, Sauda-Hylen-Lyse (from Step 2) or Lyse-Støleheia (separate project), are finished as planned, the societal benefit could be reduced by up to EUR 10 million per year with an otherwise intact grid. Such a delay could also cause further bottleneck issues in the Norwegian grid. Further delays of Steps 2 and 3 could entail a limited socioeconomic loss of EUR 7 million per year. The Germany cable is particularly exposed since it is connected to the grid further south and since commissioning is planned two years earlier than the UK cable.

Statnett can adjust the activity and measures in the Western Corridor to the progress of the Germany project. The cost estimates for Steps 2 and 3 already include this uncertainty. With planned shutdowns that cannot be avoided in 2018 and 2019, or if the grid is not intact for other reasons, the financial consequences could be greater. In these situations one must compare the value of utilising the capacity against the costs of having the capacity available. We therefore did not further reduce the profitability of the projects in our calculations to take into consideration such possible situations.

A potential delay in the upgrade of Sauda – Lyse could lead to a 15% reduction in trading capacity in the UK cable during the summer months. This only applies in export situations. The reduction could be up to 500 MW. A delay of one year will, overall, have little financial consequence for the project. In general, we consider both the risk and consequence of the UK interconnector experiencing reduced trading capacity beyond what we have already used as a basis to be minor.

The Lyse-Støleheia project is in an early phase and a licence application will be submitted in the spring of 2013. However, our analyses indicate that the market-related consequences for the cables are relatively small with an intact grid if this project is delayed.

The upgrade of the Sauda – Samnanger section will take place after the UK interconnector becomes operational. However, as is the case today, it will be necessary to have a bidding area north of Sauda. This entails that the market will handle restrictions in the grid as a result of the modification. This means that there will most likely not be a need to reduce the trading capacity on the cable.

Conditions may also arise in the transmission grid that would require the capacity to be restricted out of consideration for operation of the Norwegian system that we are not currently aware of. One possible source is planned shutdowns, and the financial consequence will depend on the situation. Beyond what we have already taken into account in our calculations as regards planned shutdowns, we do not expect major negative financial consequences over time.

In Germany, the necessary measures have been identified and are part of the existing plans for development of the grid. However, there is still a risk that the upgrades will not be completed as planned in 2022. This could potentially have a negative financial consequence. Based on routines, we previously assessed a possible loss of 5-10% of annual congestion revenues per year. In this case, this could mean a reduction in Norwegian congestion revenues of EUR 4 – 8 Mill per year.

However, whether the benefit is pulled in a positive or negative direction depends on how the bottlenecks are handled and the extent of the delays. The two most common methods for handling bottlenecks are use of price areas and counter purchase (special regulation). The German regulator has, so far, determined that it is not appropriate to introduce price areas in Germany, and that counter purchase would be preferred. This means that until the necessary grid reinforcements are in place in 2022, generation could be reduced in the interconnector for some periods, particularly in cases with too much power production in northern Germany. However, in the worst case scenario, Germany could be forced to introduce price areas to handle the major bottlenecks. However, a study conducted by Aachen University concludes that, should price areas be introduced in Germany, the congestion revenues for the planned transmission interconnector would increase. This is related to the fact that, together with introduction of price areas, the power prices in Northern Germany will to a greater extent be correlated with the wind power production, which will contribute to increasing price volatility.

The UK main grid will also undergo major reinforcements, both onshore and offshore, to ensure that there is sufficient capacity to handle the large volumes of new renewable power production which will need grid connection and market access in the years ahead. However, in the UK, the system is designed in such a way that the TSO guarantees connection to the main grid with no restrictions from a certain date. If the guarantee is not fulfilled, the cable owners will be compensated for their loss. We therefore did not reduce expected congestion revenues from the UK cable.

8.3 Uncertainty in other trade solutions

The trading capacity in the two interconnectors can be used in a number of ways. The most common practice in Norway is to give the capacity to the day-ahead market and sell it at implicit auction. Other usages include intraday trading, trade in reserves and long-term transmission rights. A fundamental principle for Statnett is to seek out the trading solutions that generate the greatest possible socioeconomic surplus. In addition, the increase in the tariff basis will be lower the more operating revenues the interconnector is able to generate.

Not using the capacity for normal day-ahead trading is primarily done because it will be more profitable or have other significant advantages. An important point is that trading with more products (day-ahead trading, reserve trading and revenues from capacity mechanisms) contributes to reduced uncertainty in the projects because which product is most profitable will vary over time and by situation. Being able to use more products will therefore generate higher and more stable revenues over time. If the capacity is only used for day-ahead trading, the profitability will be reduced by NOK 2 700 million for Germany and NOK 2 600 million for the UK.

The following section describes the uncertainty associated with the assumptions made for trade solutions. Significant deviations in trade solutions from what we expect now will be detected in the analyses before the final investment decision in 2014.

8.3.1 Long-term transmission rights

Pursuant to European guidelines, all players in the European electricity markets must have sufficient possibilities for hedging against risk between bidding areas. If there are not already liquid financial markets for hedging between bidding areas, the Framework Guideline for Capacity Allocation and Congestion Management stipulates that the system operators are required to provide long-term transmission rights ("LTR"). ENTSO-E believes there should be an exception which ensures Statnett is not required to issue LTR, but EU's member countries will make a final decision on the binding regulations. At the current date, we do not know the outcome of the case, and there is thus a certain risk that Statnett will be required to issue long-term transmission rights. However, the contract length such an order could entail is uncertain, but it is not probable that it will be significantly longer than one or two years.

If this happens, or we choose to introduce LTR ourselves, this could result in different distribution effects of the useful benefit we have used as a basis. The congestion revenues could be somewhat lower, while other players could increase their revenues. On the other hand, use of LTR will be able to provide more stable revenues and could thus be significant for the financing costs. Statnett has traditionally sold all capacity in the day-ahead market with the basis that we do not need to sell capacity in advance out of consideration to the financing, in addition to the fact that we have instruments that enable us to distribute the tariff effects of short-term fluctuations in the congestion revenues over long periods.

At the same time, it is not desirable to exclude the possibility that sale of transmission rights could be relevant in the future. To safeguard this possibility, the parties have been allowed to sell the congestion revenue through FTRs and PTRs. If the parties have different preferences with regard to such a potential sale, each party can individually decide over their share of the capacity that is reserved for the energy market. In this connection, Statnett has considered the parties' incentives and the efficiency of the flow, and such a solution has not been found to result in unfortunate consequences for the socioeconomic value of the cables.

8.3.2 Trade in reserves

Statnett assumes that we can use parts of the capacity to trade in reserves. This is done under the assumption that it provides added value beyond using the capacity for day-ahead trading. Since not all necessary regulatory permits are available at the current date, there is a risk that trade in reserves will not be possible. The European regulations describe the possibility of trade in reserves. The main rule is that trading capacity should be made available to the day-ahead market. However, there is an exception for when it can be documented that reservation contributes to a socioeconomic surplus. The financial consequence of not trading with reserves is that calculated profitability declines by NOK 850 million for Germany and NOK 750 million for the UK.

Considerably uncertainty is also associated with the actual value estimate for trade in reserves. This is because the current products for balancing services are not directly comparable as the markets for these services are immature, and because the models to simulate these markets are not good enough. Our estimates are therefore largely based on empirical analyses, as well as knowledge of theoretical correlations. We have also used power market models.

Our estimates are based on being able to use up to 300 MW for trade in reserves.

8.3.3 Capacity markets

The basic estimates for day-ahead trading benefit assume that capacity markets are introduced in both Germany and the UK. The primary effect of this is that the revenues from the cables become lower than if such mechanisms are not introduced. Statnett assumes that the cables' contribution to the other countries' security of supply is compensated.

We have assumed that both cables generate an annual revenue of EUR 30 million from capacity markets (6.2.4). It is assumed that these revenues will be split equally between the cable owners. The estimates have been added as part of the financial foundation for the calculations presented in this application. As considerable uncertainty is associated with many factors regarding such markets, considerably uncertainty is also associated with the estimates.

8.3.4 Ramping

Restrictions on ramping the cables from the Nordic synchronous area are necessary out of consideration for operational reliability, but reduce the benefit of each cable. With more cables connected to the Nordic system, it is important to look at possible improvements to the ramping rules, to reduce the consequences of operational restrictions.

The current Nordic ramping rules, which allow for flow changes of 600 MW/hour per international interconnector entail that it takes less than five hours to reverse the flow on a 1400 MW cable. Statnett is already working to change the ramping regime before Skagerrak 4 enters operation. If this is successful, continuous ramping will be in place before the planned interconnectors to Germany and the UK enter operation. If we can introduce continuous ramping, Statnett assumes that the flow could be changed with 1000 MW/hour.

This is a change from the current practice, with ramping taking place only ten minutes before and after the hour, a total of 20 minutes per hour. Continuous ramping will require amending the Nordic system operation agreement. Nordic TSOs and other affected TSOs in the CWE area have initiated work to introduce continuous ramping. According to the work plan, necessary changes to the system operation agreements in the Nordic region and central Europe must be approved by the regional operating committees.

In principle, shortening the time it takes to reverse the flow will lead to increased trading revenues from the interconnector. The basic estimate assumes 1000 MW/hour, and the profitability will be reduced if this is not achieved. The scope will depend on the price differences during the relevant time period and how quickly the flow can actually be reversed. Systematically, the price differences during ramping hours are smaller than otherwise, but the lost benefit could still be considerable with a long ramping period.

Our analyses indicate that the loss from the cables not being able to reverse the flow immediately corresponds to about 1% of the congestion revenues. This is included in the applicable estimates. Further loss of revenue with a ramping rate of 600 MW/hour is about 1% for the UK and 2% for Germany. If the flow is reversed based on 400 MW/hour, the total loss in congestion revenues will be about 3.6% for the UK and 7.1% for Germany, respectively. The reason why the commercial consequences of non-continuous ramping are greater for Germany is likely to be related to the duration curves for the power prices and associated power flow. We expect more one-sided power flow in the UK interconnector, and thus less need for ramping, due to expectations of higher power prices there.

Agreed ramping regime initiative

The parties in both projects agree to try and establish a good ramping solution. Nordic TSOs and other affected TSOs in the CWE area have initiated work to introduce continuous ramping. The system operation agreements in the Nordic region and in central Europe have to be changed, and the changes must be approved by the regional operating committees.

An agreement on the ramping regime in each project will be achieved before an investment decision is made.

8.3.5 Flow-based market clearing

Statnett analyses and assesses the possibility of introducing flow-based market clearing. A transition to flow-based market clearing in the Nordic region could potentially have consequences for the profitability of new cable interconnectors through strengthening the capacity in the Nordic power grid. This work is at a very early stage and it is not currently possible to explore how a potential introduction would impact the cable interconnectors.

8.4 Uncertainty in cost estimate

The assumptions for the cost estimates are associated with uncertainty. The below figure shows the general correlation between the percentage of permanent changes in annual costs and change in calculated present value. The figure also shows that the investment costs (including domestic grid reinforcements) are the only significant cost item.

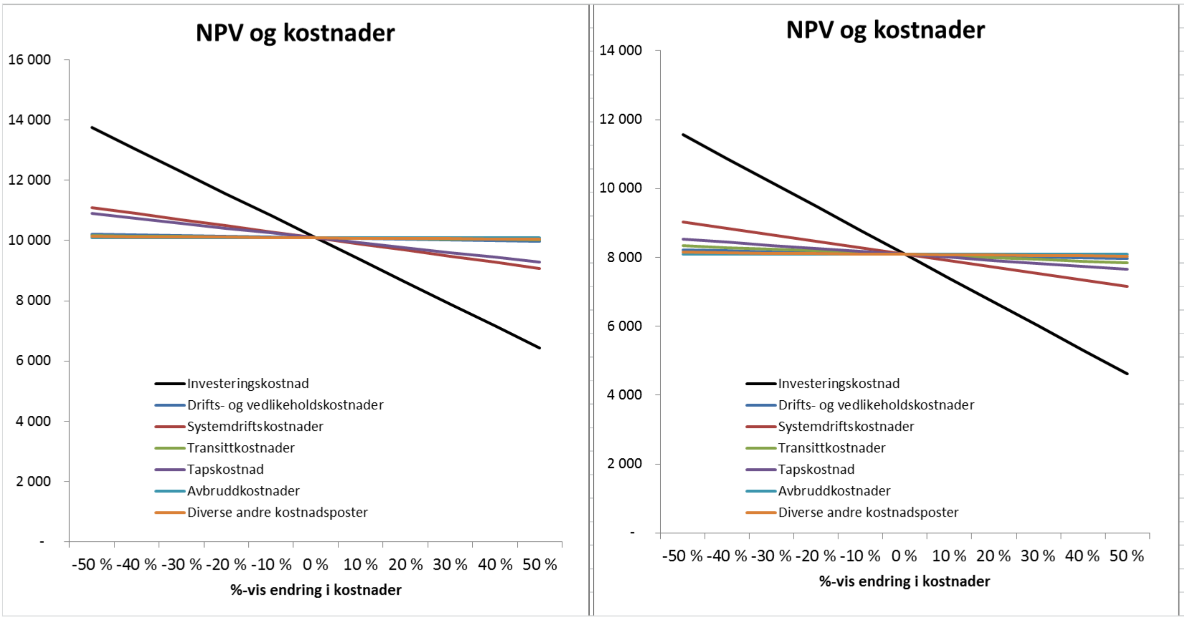


Figure 6: The correlation between the percentage of permanent changes in costs and present value for Germany (left) and the UK (right).

The following section discusses the uncertainty in the various cost elements in more detail.

8.4.1 Investment costs cable, power line and onshore facility

The result from the cost estimation for Germany shows a basic estimate without building loan interest of NOK 10 800 million, and an uncertainty mark-up of about NOK 1 800 million. The expected investment cost for the cable, power line and onshore facility is then NOK 12,600 million (Statnett's share is 50 %). The expected cost framework (P85, the cost the project is within with 85% probability) is NOK 15 200 million. The uncertainty is in the interval +/- 25%. Costs from domestic grid reinforcements are not included in these figures.

For the UK, the basic estimate (without building loan interest) is estimated at about NOK 12 000 million and the uncertainty mark-up is NOK 1 700 million. In total, this results in an estimate of NOK 13 700 million (Statnett's share is 50%). P85 is about 16 300, and the uncertainty analysis concludes an uncertainty interval of about +/- 25%. Costs from domestic reinforcements are not included.

The socioeconomic profitability for changes in investment costs is shown in the below table. All figures are in NOK million and present value.

Situation	Germany 2018	The UK 2020
Expected (P50)	10 100	8 100
Reduction of 25%	11 450	9 500
Increase of 25%	8 650	6 700
P85	8 900	6 900

Table 9: The present value of the socioeconomic profitability as a function of changes in investment costs. All figures in million NOK.

The below section discusses the various assumptions used as a basis for the investment costs.

Changes in the projects' scope, technical solution and extreme incidents

The investment costs are estimated according to Statnett's guidelines for cost estimation where an uncertainty analysis was carried out of the basic estimates. Even though a thorough uncertainty analysis has been carried out, it does not cover all imaginable future incidents. For example, the uncertainty analysis does not include significant changes to technical solutions or changes to the projects' scope. Neither have incidents with a small probability and major consequence (extreme incidents) been included in the analysis. This means that changes to the project's technical solutions and scope, as well as extreme incidents, could result in changes in the investment costs.

Procurement of cable and converter

The supplier market for cables and converters is characterised by few providers and many competing projects. A market situation which deviates from what we have used as a basis could, to a certain extent, change the cost estimate.

Submission of inquiry documents will be important to determine whether the projects can be implemented within the schedule and cost estimate used as a basis. If it turns out that this cannot be done and e.g. leads to delays of several years or increases the construction time by several years, this will result in such vast changes in the projects that it must be handled separately. Any changes in the projects will be addressed and assessed in the socioeconomic analysis when the investment decision is made.

Progress plan

The cost estimate assumes an investment decision will be made by mid-2014 and commissioning will take place at the end of 2018 for the Germany project and the end of 2020 for the UK project, and that the projects will otherwise be carried out in accordance with the planned progress. The uncertainty associated with the schedule for the projects is primarily related to supplier capacity. Costs associated with changes in the schedule are included in the uncertainty analysis, and thus in the expected investment cost. The progress plan assumes that the necessary licences are awarded in time and that the supplier market can deliver the required services. Any extraordinary additional costs of maintaining the planned progress in the event of unforeseen delays have not been included in the cost estimate.

Currency and raw material prices

Up to 2014, the analysis has taken into account uncertainty in metals and currency. Exchange rates and raw material prices must be hedged in accordance with Statnett's practice when entering into supplier contracts immediately following the investment decision which is planned for mid-2014.

The projects are thus exposed to changes in exchange rates against the currency the costs arise in, particularly against the dollar and euro. An appreciation of Norwegian kroner could result in reduced investment costs as a result of our costs measured in Norwegian kroner being reduced. Correspondingly, depreciation of Norwegian kroner could result in more expensive procurements measured in Norwegian kroner.

Metal costs constitute about 20% - 30% of the cable costs, and 50% of these are copper and lead. Copper has been particularly volatile in recent years. The copper price has fluctuated between USD 6 000 – 10 000/tonne over the past two years, and is currently about USD 8 000/tonne. Until the raw material prices are fixed in mid-2014, the projects are vulnerable to changes in these prices. The uncertainty analysis uses +/- 25% as a basis.

8.4.2 Unforeseen domestic grid investments

There could be a need for further investments in the Norwegian grid which we have not yet identified. The financial consequence will correspond to the present value of the net cost that would then have to be allocated to the projects in line with the principles described earlier. The likelihood of this scenario is considered minor in light of the comprehensive work carried out analysing the grid situation in Norway, and the extensive upgrade plans that will be implemented.

Costs for Sauda – Samnanger are included in the profitability calculations for the UK project. Sauda – Samnanger is in a particularly early phase where the need is still being assessed. A potential reduced need for this measure, for example as a result of introduction of flow-based market clearing, will increase the calculated profitability of the interconnector. This could be caused by the project being implemented later than predicted or that the net cost is lower than expected.

The actual level of the allocated costs from domestic grid reinforcements is also associated with uncertainty. The estimates are based on expected values as several of the projects are in early phases. However, these values have been subject to separate uncertainty analyses. Furthermore, there will be an assessment of which distribution to be carried out between forced reinvestment, accrued costs and that which is related to capacity increases as a result of the interconnector (this mainly applies to the Western Corridor Step 1).

8.4.3 Transit costs (Inter-TSO Compensation - ITC)

Future design of the ITC regime in Europe could positively or negatively impact the socioeconomic profitability. The greatest risk is associated with a potential increase in the scope of the scheme. This could entail significant higher revenue for Norway. For Germany, the risk is reduced through a contractual agreement to share costs and revenues from flow in the Germany cable.

It is difficult to assess what impact the ITC compensation will have on the new cable. There are several reasons for this:

1) It is uncertain how extensive the European ITC settlement will be in the future. A process is ongoing to evaluate the scope of capital compensation. A consultant report prepared by Conscentec on behalf of ACER suggests a considerable increase in compensation for capital expenditure, up to EUR 1500 million/year.
2) is uncertain how power trading in all of Europe will develop. In isolation, increased total trading will entail that the Norwegian cost is reduced, as the scheme is shared between everyone that is a net exporter or importer, measured hour by hour.
3) is uncertain how the flow in the new cable and the interaction with flow in the other cables will be.

ACER recently expressed a desire to the commission to limit the fund to existing infrastructure and that it should then be phased out and replaced with a model that shares investment costs based on benefit calculations. This will be reassessed in 2015.

8.4.4 System operation costs

The system operation costs are considered uncertain with regard to the fact that it is challenging to estimate the future need and price level. Even though the outcome for system operation costs can be relatively large, the cost level is of such a size that the significance of the uncertainty is relatively minor.

8.5 Discount rate

The choice of discount rate is very significant for the calculated profitability, and the projects' sensitivity should be tested through sensitivities. Previous assessments made in connection with NorNed and NSI, among others, recommended a higher discount rate. There are several reasons for the estimate being relatively higher than what we use, but the most important are related to assessments of real interest and what is a reasonable mark-up for systematic uncertainty.

The real interest is currently at a historically low level, and most applicable estimates of this size are in the order of 2.0% - 2.5%. The level of the risk mark-up is driven by what is a suitable estimate for systematic risk and future return on a reference portfolio. Previous analyses commissioned by Statnett have concluded a risk mark-up in the interval of 2.5% - 3.5% for grid investments, including interconnectors, while NOU 2012:16 recommends a risk premium of 1.5% for a normal public project.

With this basis, a reasonable interval for the discount rate is in the interval between 4% - 6%. This generates a profitability in the order of NOK 5 150 million to NOK 10 100 million for the Germany cable. The project's calculated internal rate of return is approx. 11%, so the project is robust in relation to reasonable discount rate levels. The internal rate of return can be interpreted as the capital that is tied to the project at any given time. The internal rate of return is the discount rate that makes the present value equal to nil.

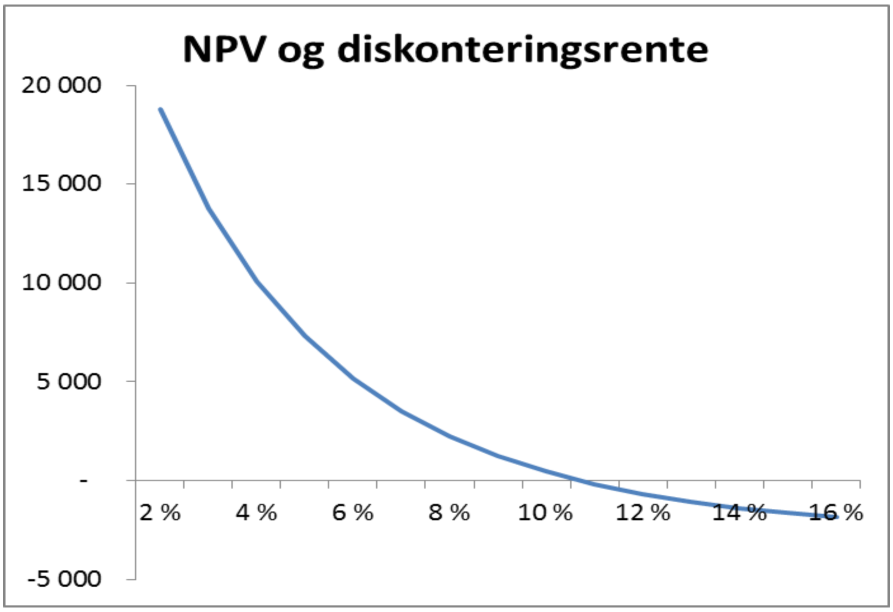


Figure 7: The correlation between calculated present value (million NOK) and the choice of discount rate for Germany.

For the UK, a discount rate in the interval 4% - 6% yields profitability in the order of NOK 3 750 million to NOK 8 100 million. The project's calculated internal rate of return is approx. 10%, so the project is robust in relation to reasonable discount rate levels.

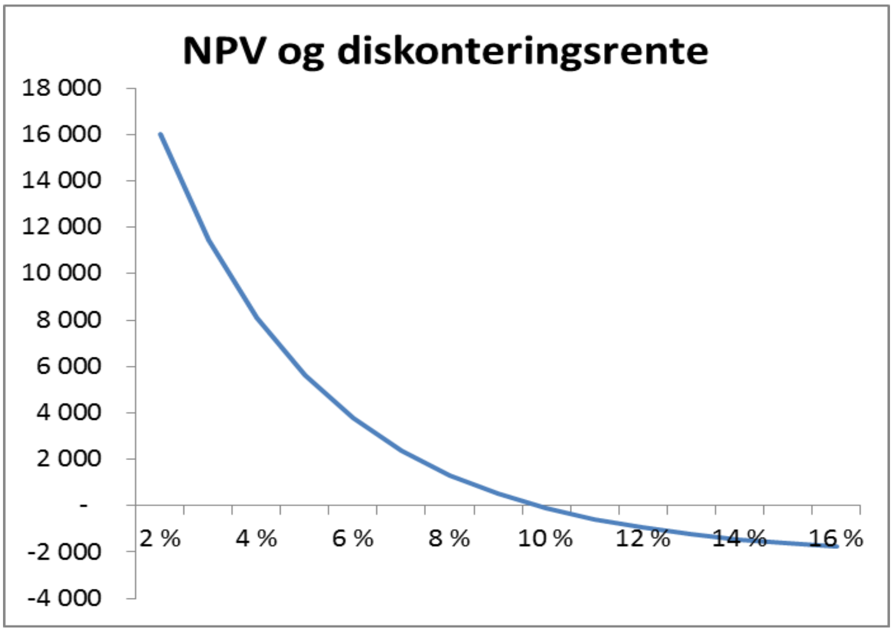


Figure 8: The correlation between calculated present value (million NOK) and the choice of discount rate for the UK.

8.6 Commissioning

Delayed commissioning will reduce the profitability of the projects, while an earlier start-up than planned could increase profitability. Whether the delay or acceleration would also result in changes to the cost level must be balanced against the advantages of early commissioning.

Both projects are planning to enter into supplier contracts in mid-2014 and commissioning of the Germany cable is planned in 2018 and the UK cable in 2020. The planned progress is contingent upon necessary licences being granted in time, as well as that the supplier market can deliver the products the projects need at the right time. In addition, other considerations, both in Norway and with the partners could delay commissioning, but a more detailed review of possible causes will not be presented here. The projects operate with normal principles for risk management in relation to progress. Thorough risk assessments and uncertainty analyses of the implementation plans will be established before investment decisions are made.

A simplified calculation indicates that a one-year delay would result in a lost present value of approx. NOK 550 – 650 million for each of the projects if other costs are not changed significantly. If a decision is made to implement measures to maintain the progress plan, this could have cost consequences that are not included in the simplified calculation above.

8.7 Analysis horizon, lifespan and residual value

The interconnectors are expected to have long lifespans, possibly also exceeding the predicted 40 years. The effect of a changed lifespan on the profitability will be as follows (without other significant changes in costs or revenues):

- If the lifespan exceeds 40 years, the profitability assessment is too low
- If the lifespan is shorter than 40 years, the profitability assessment is too high

There are few empirical observations of the lifespan of such cable interconnectors, but experience from the Skagerrak interconnector indicates that the technical lifespan is greater than 40 years. The remaining predicted lifespan of the oldest Skagerrak cables is significant, and their total lifespan will probably exceed 50 years. The financial consequence of this takes place far ahead in the future, and there is also the question of whether to include the need for reinvestments. If the system is able to operate for 45-50 years before significant reinvestments are needed, and the analysis horizon is increased correspondingly, the profitability for Germany will increase by NOK 8 00 - 1 500 million. Corresponding figures for the UK are NOK 700 – 1 300 million.

The calculated residual value is based on a simple approach, and is an expression of the present value of the book value of the domestic grid reinforcements. In practice, the residual value of these systems will be higher, cf. e.g. the discussion on real options and the value of available capacity that can be used for other purposes. Furthermore, the metal in the subsea cables could have a residual value which it may be profitable to collect and sell if the cables are being removed or reinvested. The value of this has not been calculated. The costs of removing the cables must be potentially deducted for this.

8.8 Transmission capacity

As regards trading capacity, the financial analyses have assumed 1400 MW on the sender side of the interconnectors for both projects. For the Germany project, the capacity will most likely be defined on the receiving side. It involves a financial benefit equivalent to the increased trading capacity being made available.

8.9 Downside scenario

The sensitivities described above describe the financial consequence if only one factor is changed at a time. To get a better description of the socioeconomic profitability when multiple simultaneous negative incidents occur, we prepared a downside scenario. This is not an expression of what we consider the worst imaginable outcome, but rather a possible future scenario that could result in low socioeconomic profitability. With a basis in previous assessments, we have constructed the following downside scenario:

- Low revenues from day-ahead trading (cf. previous discussion)
- No revenues from trade in reserves
- No revenues from participation in capacity mechanisms
- Higher investment costs (P85) of subsea cable and converter
- Reduced lifespan/analysis horizon to 30 years.

The estimated socioeconomic profitability for the Germany project in this scenario is about NOK 1 000 million. The consequences of non-priced effects will come in addition.

The estimated profitability for the UK in this scenario will be negative with about NOK 300 million with a discount rate of 4%. Since this scenario takes into account considerable uncertainty in the project's cash flows, it could be argued that it would be reasonable to use a discount rate that is closer to the risk-free real interest to prevent "double correction" of the uncertainty. The internal rate of return before residual value is thus about 3%, i.e. above risk-free real interest. The consequences of non-priced effects will come in addition. In this scenario the power balance in the Nordic region is tighter and the cables' significance for security of supply will be relatively greater.

We have previously discussed that the cost estimates for domestic grid reinforcements are uncertain, and increased costs here could further reduce profitability. The same applies to delays in the Western Corridor and potential further reductions in trading capacity.

8.10 Upside scenario

In the same way as in the previous chapter, it is relevant to describe the financial consequences of a scenario that involves multiple simultaneous positive incidents. The scenario is not considered the best hypothetical outcome, but rather a possible future with high profitability.

- Higher revenues (cf. previous discussion)

- Lifespan and analysis horizon: 50 years

This results in a socioeconomic profitability of approx. NOK 18 600 million for the Germany project and approx. NOK 16 250 million for the UK if other assumptions remain constant.

8.11 Summary of uncertainty analysis

Based on the previous uncertainty analysis, both projects appear to be robustly socioeconomically profitable for Norway. The review of the outcome for revenues from day-ahead trading shows that the cables have high revenues in a broad spectrum of future development characteristics. The negative correlation between changes in congestion revenues and consumer/producer surplus underlines this point.

Furthermore, the analyses show that the projects are also socioeconomically profitable if the capacity is only used for day-ahead trading. However, the profitability is less robust.

As regards costs, the investment costs for the cable and converter, as well as the domestic grid reinforcements primarily have an effect on profitability. Our uncertainty analysis of the investment costs in the actual cable and converter also indicates that the profitability is robust. Delays in the work on the Western Corridor could entail more extensive reductions in trading capacity than what we have predicted, but the financial consequence of this emerges as relatively minor compared with the projects' total profitability. The two cable projects would emerge as profitable even if all the costs for the Western Corridor were transferred to the cable projects.

We have also looked at what situations could result in both low and high socioeconomic profitability. Even in situations where we take into account multiple negative incidents at the same time, the projects do not emerge as unprofitable for Norwegian society. The projects also emerge as profitable with regard to choice of discount rate.

In addition to the present value being high, the projects' internal rate of return is also high and the repayment time is short for being an infrastructure project with a long lifespan.

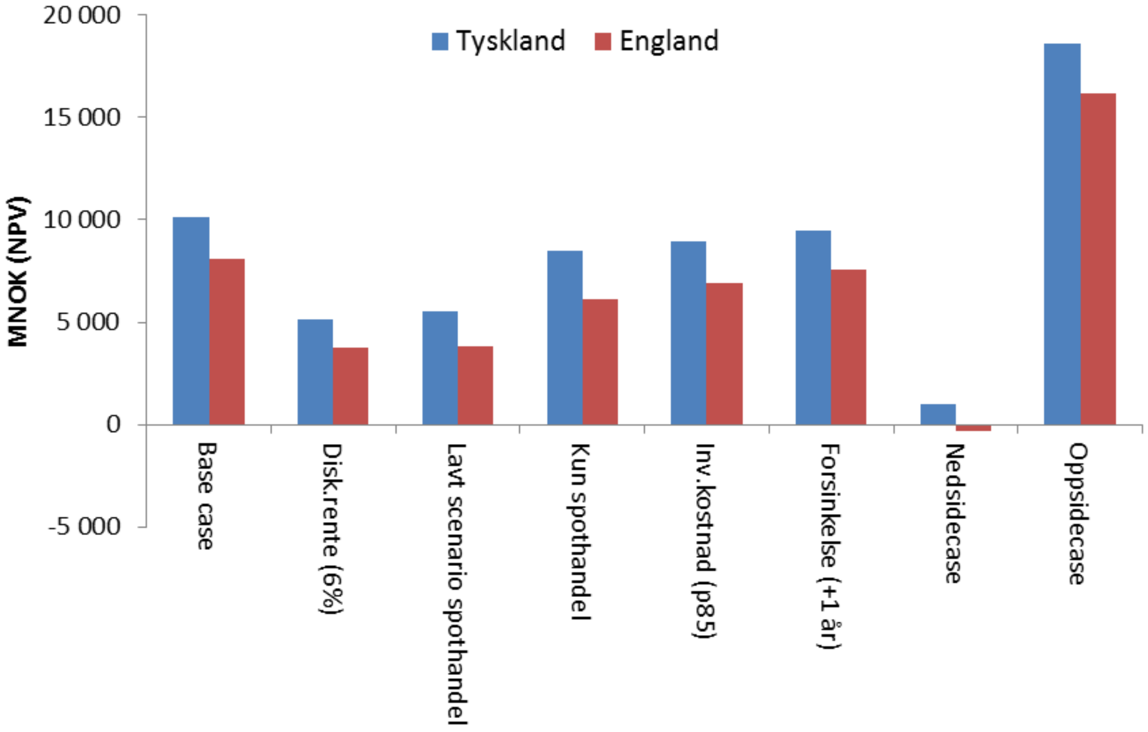


Figure 9: Summary of the uncertainty analysis (NPV as function of: 1 - Base case, 2 – Discount rate = 6 %, 3 – Low scenario for congestion revenues from day-ahead trade, 4 – Only revenues from day-ahead trade, 5 – Investment cost = p85, 6 – Delayed operation = 1 year, 7 – Downside scenario, 8 – Upside scenario).

SECTION IV APPENDICES

1 Socioeconomics – method and assumptions

1.1 Socioeconomic method

The planned interconnectors are investments in new trading capacity between different market areas. The physical utilisation of the interconnectors will be governed by well-functioning power markets at each end of the cables. The development of the European codes will contribute to equal and efficient trade solutions across Europe. Our assessment of the socioeconomic profitability can thus take a basis in the same framework used by Statnett when analysing investments in the Norwegian/Nordic grid, and that we have used for NorNed and SK4.

A grid investment is socio-economically profitable if benefits from increased transmission capacity are greater than investment costs and the increase in variable costs (including environmental costs).

The calculations are limited to effects on Norwegian socioeconomics, i.e. effects for international players are initially not included. However, the market analysis still shows some consequences for other Nordic countries. The analyses only look at effects in the power system.

The profitability assessments are based on studies carried out by Statnett with support from external consultants.

When calculating socioeconomic profitability, actual sizes have been used as a basis, and both priced and non-priced effects must be assessed. All positive and negative effects are quantified in Norwegian kroner insofar as possible. This is based on the principle that a consequence is worth what the overall population is willing to pay to achieve it. If the willingness to pay for all the measure's benefits is greater than the total costs, the measure is defined as socioeconomically profitable (NOU 2009: 16).

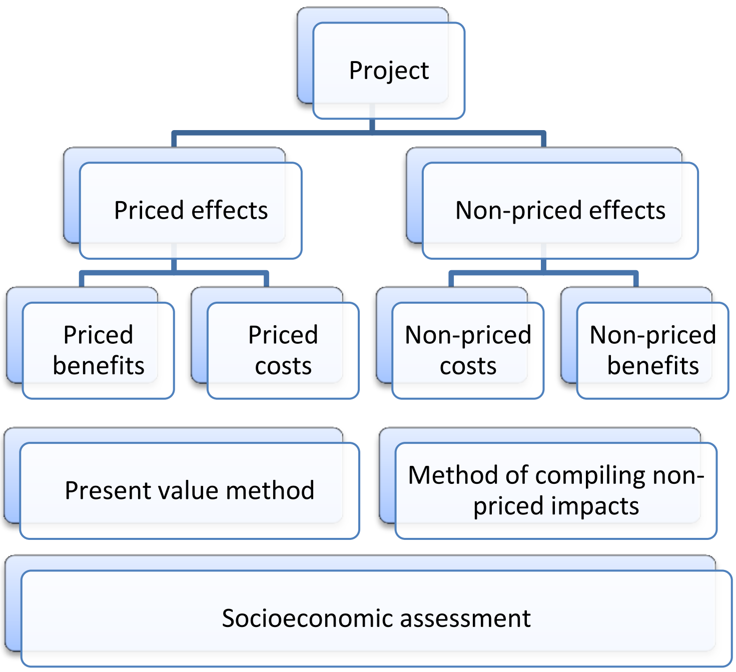


Figure 10: Schematic presentation of our approach to the socioeconomic analysis.

The priced effects are:

- Investment costs for a subsea cable, land cable, power line, station facility and project development
- Reinvestments in a station facility for components with shorter lifespans than the analysis horizon
- Investment costs for domestic grid reinforcements
- Operating and maintenance costs for a cable, power line, onshore facility and insurance
- Value of energy trading:
    - Capacity revenue between Norway and recipient country
    - Transmission loss in cable and onshore facility
    - Change in capacity revenue in other interconnectors
    - Change in consumer and producer surplus
- Change in loss costs in the Norwegian transmission grid
- Change in system operation costs
- Change in transit costs (ITC)
- Trade in reserves
- Participation in capacity mechanisms

Not all relevant effects can be evaluated in a satisfactory manner, they are called non-priced effects. However, these components could be very significant in relation to the socioeconomic assessment.

Very negative consequence	Major negative consequence	Medium negative consequence	Minor negative consequence	No/ insignificant consequence	Minor positive consequence	Medium positive consequence	Very positive consequence	Major positive consequence
----	- - -	- -	-	0	+	++	+++	++++

Table 10: Consequence scale used to assess the significance of non-priced effects.

<u>The non-priced effects are</u>:

- Security of supply
- Efficient power market
- Climate and environment

We have also considered real options. The decision to implement a measure is always based on the information available at the time of the decision, and occasionally measures can be designed such that the content can be adapted if new information comes to light. The option can have a positive value by the measure being adapted to future benefit and cash flows.

In our case we have not identified any relevant real options of adapting the costs, but there is an option on the revenue side. A grid reinforcement that is necessary for an interconnector could increase the transmission capacity by more than what is needed by the cable alone, and thus release capacity for other purposes.

1.2 General assumptions

1.2.1 Discount rate

The socioeconomic consequences of an investment in new international trading capacity are long-term in nature, both as regards the benefit and cost. An overall assessment of the measures' effects requires that we compare the costs and benefit that accumulate at different times. The long-time perspective also emphasises the underlying uncertainty associated with future costs and revenues.

All financial analyses must take relevant uncertainty into consideration. This is normally done by discounting future cash flows to a joint time (present value) where the discount rate is represented through the investment's return requirement. The return requirement should be equal to the rate of return the bound capital could have had in the best alternative use, and consists of a risk-free interest and a risk mark-up.

The term risk can be divided into systematic and unsystematic risk. The unsystematic risk is project-specific and managed by the cash flows reflecting expected values to the extent possible. The size of the risk mark-up should depend on correlation between the project's rate of return and the state of the Norwegian economy. Also to what degree the value of the project is sensitive to economic trends (systematic risk). A positive correlation increases the project's risk, while a negative correlation reduces the risk.

The discount rate has a significant impact on profitability at the same time as there is considerable uncertainty regarding what is the right level. There are several methods for estimating the discount rate and they all have their own strengths and weaknesses. Despite this, the common practice still involves using the principle that one krone tomorrow is less worth than one krone today due to risk and the time aspect.

NOU 2012:16 about socioeconomic analyses was published in October 2012, and addresses choosing a discount rate. It recommends the following:

- In principle, the real risk-adjusted discount rate should reflect risk-free interest and the risk in the project and thus reflect the project's alternative cost. However, the discount rate for use in an assessment of public measures should be based on simple rules that identify the most important aspects of the issue.
- For public business operations in direct competition with private players, it will be natural to use a discount rate corresponding to that which private companies are using.
- For use in socioeconomic analysis of a normal public project, such as a transport and communication measure, a real risk-adjusted discount rate of 4 per cent would be expedient for effects in the first 40 years from the time of analysis.
- Beyond 40 years it is reasonable to assume that one cannot ensure a long-term interest rate in the market and the discount rate should then be determined based on a declining certainty equivalent interest rate. An interest rate of 3 per cent is recommended for the years from 40 to 75 years in the future. An interest rate of 2 per cent is recommended as a discount rate for the following years.

Following an overall assessment, the committee does not recommend establishing multiple risk classes with varying risk-adjusted discount rates. For measures that clearly have a low or negative systematic risk, it will be natural to use a lower discount rate. For measures that clearly have a higher systematic risk it is correspondingly expedient to use a higher discount rate.

In line with the proposition to the Storting relating to amendments to the Energy Act, we assume that Statnett is not in direct competition with private players. Using private players' commercial return requirements is therefore not considered relevant.

Our analyses indicate that the projects' benefits have a low positive systematic risk. The systematic risk depends on a number of factors such as the power prices in the relevant countries, correlations between the two countries' net national product and how sensitive the power prices are to changes in cyclical trends. Cable projects have another type of systematic risk than ordinary grid projects and other public projects, but not necessarily higher.

The power prices are determined by the marginal cost for the final producing unit each hour. In a hydropower-based power system, the alternative cost (hydropower value) often corresponds to the value of producing power at another time. Due to the Norwegian hydropower value being dependent upon international power prices, the Norwegian price level is impacted by economic trends. In Norway, as in other countries, consumption of electricity will be sensitive to economic trends. Increased Norwegian power consumption as a consequence of a positive economic trend in Norway will, in isolation, normally increase the power price in Norway. In the thermal market the marginal cost is often determined by the raw material prices of the inputs in the production, for example coal, oil and gas. Increased fuel costs (particularly due to gas and oil) will normally result in increased revenues for both the cables and the Norwegian economy in general.

As a rule, an upward economic trend in Norway is positively correlated with an upward economic trend with our trading partners as a result of international trading, and a positive economic trend normally generates increased power prices in both Norway and with our trading partners. The relative change between the power prices in Norway and abroad is the relevant factor for the systematic risk. If the price increase abroad is larger than in Norway, the systematic risk will be positive with Norwegian export (the price difference will then increase) and negative with import (price difference is reduced). If the relative price increase abroad is smaller than in Norway, the systematic risk will be negative in export (price difference is reduced) and positive in import (price difference increases). This also means that balanced power trading will pull the systematic risk down towards nil.

Our assessment is that international power prices are more sensitive to economic trends than Norwegian power prices and we anticipate more export than import in the interconnectors. At the same time, we know that congestion revenues and changes in PS/CS are negatively correlated. The consequence of this is that the projects' total revenues are more stable than what the congestion revenues would indicate. Overall, we therefore believe that the systematic risk is positive, but low.

Furthermore, the projects have a high percentage of fixed costs that accrue early on which means that the cost level cannot be adapted to the revenue level at a later date. Revenues and costs are also sensitive to the development in certain exchange rates.

Historical price differences between Norway, Germany, the Netherlands and the UK show that Norwegian power prices are less correlated with UK power prices than with German and Dutch. A UK interconnector would thus constitute an uncorrelated individual element in the cable portfolio that will contribute to reducing volatility in the cable portfolio's total profitability and in turn reduce the total risk. In the long term, price formation in Germany and the UK is expected to converge because both countries will become more dependent on gas power in our 2030 scenario and that the UK will be more closely connected to the Continent.

Over time, a positive correlation is for this reason expected between the project's revenues and the Norwegian economy as a whole. We believe the systematic risk is not substantially different from a normal public project. Based on the recommendation from NOU 2012:16, we are using a discount rate of 4% for the first 40 years and then 3% for the remainder of the analysis period. The sensitivity to the selected discount rate is tested through sensitivities.

1.2.2 Exchange rate

The projects will make procurements in foreign currency, particularly in euros and dollars, while revenues will arise in euros that will later be exchanged into Norwegian kroner. When estimating the investment cost, relevant exchange rates and commodity prices at the time of estimation are used as a basis in the basic estimate, and variations of this are detected in the uncertainty mark-up. Commodity prices and exchange rates are secured when entering into supplier contracts..

We assume that the settlement for trading via the UK interconnector will take place in euros as far as Norway is concerned. This has not been clarified at the present time.

Currency	2013	2014	2015	2016	2017	2018	2019->
NOK/EURO	7.39	7.52	7.66	7.81	7.96	8.1	8.1

Table 11: For exchange rates, Statnett uses observed forward prices as at 2 January 2013 as a basis.

1.2.3 Lifespan, analysis period and residual value

As mentioned, the interconnectors will have an impact for a long time in the future. Assumptions about the lifespan, analysis period and residual value have a potentially major impact on the calculated socioeconomic profitability.

We define the lifetime as the period the measures are expected to be in use. The technology which the projects will use is well-tested and there is plenty of operational experience.

Based on other HVDC cables and the projects' own design requirements, Statnett assumes that the technical lifespan and financial depreciation period is 40 years, which is the same as for NorNed. At the end of the lifespan, a major reinvestment will be an independent decision with a designated socioeconomic analysis.

For domestic grid investments, a lifespan of 70 years is used for power lines and 40 years for substations at an aggregated level.

In order for all impact to be detected, the lifespan and analysis period should ideally coincide. We will set the analysis period to 40 years following commissioning of the project. A normal simplification when calculating socioeconomic impact is keeping all prices fixed throughout the analysis period. This was also done here, unless otherwise specified. A noteworthy exception is the benefits from day-ahead trading where we have estimates for 2020 and 2030. For the years between we interpolate the figures so the actual values are not constant during this period. After 2030, we are keeping all significant effects constant for the duration of the analysis period (with a small exception for operating and maintenance costs).

Due to the correlation between the depreciation time and analysis horizon for the cable and converter, the residual value will be nil with the exception of the residual value of the domestic grid reinforcements. This residual value is calculated as the present value of the book value of the systems at the end of the analysis period.

1.2.4 Taxes

The planned expansion of trading capacity out of Norway is of such a scope seen in relation to the size of the power systems that the prices and revenues from sale of power are impacted. The considerable extent of public ownership of power production means that a large share of the gains ends up as revenues for the public sector. Because the hydropower stations utilise local resources, the host municipalities also receive a proportionate share of the resource value through taxes, fees and compensation in the form of power to the host municipality for electricity production. This means that the power supply contributes to considerable value transfer, not just to the state, but also directly to the municipal sector.

Our analysis assumes that changes in taxes, fees and gains are an allocation effect between power companies, consumers and the state, and this has not been assessed further. The measure is not financed through the national budget, and introduction of new taxes or fees is not planned at this date. We assume that additional costs for collection of the increased tax revenue will not accrue. Rather, one could argue that, since the state's tax revenues are increasing, the tax financing costs are reduced. The Ministry of Finance's guidelines recommend using a tax expense of NOK 0.20 per krone of collected taxes. We have not calculated the net increased revenues, and keep the positive effect outside our analyses.

We assume that the NorNed model will be used as a basis when paying income tax and VAT, which means that Statnett will pay taxes and fees in Norway according to Norwegian rules. We thus do not anticipate any tax leaks. At the current time, this has not been finally clarified with Norwegian and foreign tax authorities, and there is a risk that Statnett will have a place of operation in Germany and/or the UK with the tax implications this might have. A potential consequence could be tax leak from Norway to abroad, which could be a socioeconomic cost that is not included in the calculations.

Property tax is tax paid according to the value of real property to the municipality where the property is located. Originally, the property tax was intended to cover the municipalities' expenses in connection with real property in the municipality. Today, the property tax is often more fiscal in nature, as it can be managed relatively freely. Our facilities are not expected to result in significantly increased costs in the host municipalities. Property tax is thus considered a marginal redistribution effect between grid customers and the municipality, and is not described further.

All figures in the analyses are exclusive of VAT.

1.2.5 Ownership model

For both projects, it is assumed that the ownership is split 50/50 between Statnett (Norway) and our international partners, TenneT/KfW in Germany and NGIL in the UK. In practice, this means that direct project-specific costs are split 50/50 between Norway and Germany and Norway and the UK, respectively.

Direct project-specific costs means investment costs in cables and onshore facilities, operating and maintenance costs and loss costs in the facility. System costs, costs from domestic grid reinforcements behind the converter and transmission loss in the underlying grid, are not shared. Change in transit costs and revenues in Norway and Germany as a result of the Germany cable will be split 50/50 with a partner, while the costs will go to each country for the UK cable.

For the revenues, it is assumed that congestion revenues, gains from sale of reserves and revenues from capacity mechanisms will be split evenly between the countries. Changes in consumer and producer surplus will remain in Norway, while changes in congestion revenues in other cables will not be shared with the partners in the UK and Germany, but according to established distribution keys.

1.2.6 Trade solutions

Development of a joint integrated European power market with associated adjustment provides certainty of efficient, liquid and transparent trade solutions on both ends of the interconnectors. In addition, the final agreed trade solutions between the partners have a major impact on the projects' socioeconomic profitability. The analyses use the trade solutions we want and think we can achieve at the present time as a basis.

The following trade solutions are used as a basis for the socioeconomic analysis for both interconnectors:

- All day-ahead trading will take place through the new market coupling algorithm that is developed for all of North-Western Europe and we will thus also have implicit auction for these cables
- Transmission loss from the cables is included in the market algorithm so trading only takes place if the price difference is at least as large as the marginal loss cost
- Up to 300 MW can be used for trade in reserves under the assumption that it is at least as profitable as day-ahead trading, and that the optimisation takes place continuously
- The cables are rewarded through capacity mechanisms
- Ramping restrictions place few restrictions on trade benefits (entails change from current rules).

Utilisation of the interconnectors is governed by the power prices at each end of the interconnector. When the relationship between the power prices in the two areas has changed, the power flow in the cable could also change. Such changes cannot take place too quickly out of consideration for operation of the power system. Ramping restrictions corresponding to 1000 MW per hour per interconnector are used as a basis. In other words, the current rules are expected to change, and this will take place well before commissioning.

Should the final trade solutions be different from this, it could have consequences for the socioeconomic profitability.

1.2.7 Other assumptions

The socioeconomic analysis is made with a basis in actual sizes. Input to the analyses is in 2012 NOK, but we want the profitability to be presented in a value as near as possible to the time of decision. To convert to 2013 values, we assume that the actual prices are constant, and can thus be converted using expected inflation in

2013. As at March 2013, Statistics Norway quotes that it is 1.5%. A change in the present value time will also change the discount, so the total effect of the conversion is equal to the nominal interest rate in 2013. This means approximately 5.6% (nominal interest rate = real interest rate + inflation + real interest rate*inflation). All inputs in the application are presented in 2012 NOK, while all results and present values are converted to 2013 NOK.

The cables' energy availability is important for estimating benefits and costs. The availability is impacted by planned maintenance, technical faults and preparedness solutions. It is assumed that the converter will not be operational for one week a year for maintenance and about 20 hours for interruptions in the control systems. With good onshore preparedness, downtime as a result of faults in the cables is expected to be approx. 1.5 weeks a year. The total predicted availability is then approx. 95%. This corresponds with observed sizes for other interconnectors.

As mentioned, we focus on the impact for Norway. This raises the question of to what extent one should correct for Norwegian ownership interests abroad and foreign ownership interests in Norway. Due to the complexity of a potential assessment, we choose to stick with borders. We therefore do not correct for this.

1.3 Relationship with other interconnectors

1.3.1 New interconnectors

To the degree international transmission capacity cannot be developed endlessly, it should be utilised in the manner which best serves Norwegian society in general. Key relevant factors when developing cable interconnectors are maturity, time horizon, grid conditions, trade solutions, partners, project risk, technical solution and equity.

Development of an international cable project is an extensive process. The UK and Germany projects are, from Statnett's viewpoint, the only ones with a status as actual decision alternatives, and are, following a comprehensive assessment, the best projects at the current date. It is uncertain whether, and potentially when, other alternatives could be realised.

Several other cable interconnectors to the Continent have been considered. Statnett has acquired NorGer and relevant information and the basis from this are included in the current Germany project.

NorthConnect is a project company currently owned by private players in Sweden and Norway and their objective is to build and operate an HVDC interconnector between Scotland and Norway.

A new cable to the Netherlands (NorNed2) has been considered, but could not be realised within the framework allocated for the project. As of today, NorNed2 is not a relevant decision alternative.

1.3.2 Socioeconomic profitability previous projects

The investment in NorNed in 2004 was expected to result in a socioeconomic benefit of approx. NOK 160 million per year over the project's lifespan. The annual costs were approx. NOK 200 million, whereas the expected value of the revenues/benefits was NOK 360 million. The expected present value of the project was approx. NOK 2 000 million. Key assumptions were that the cable became operational on 1 January 2008, the lifespan of the facility was 40 years and the actual discount rate was 6%. Our analyses indicate that the project has been and is very socioeconomically profitable for Norway and the Netherlands. The cable became operational in May 2008, and, so far, earned congestion revenues constitute about half of the accrued costs.

The net present value of SK4 upon submission of the licence application and approval of the agreement (autumn 2009) was assessed at between NOK 1 000 and 2 000 million. An updated profitability assessment in 2010 indicated that the present value was approx. NOK 2 100 million, including a share of domestic grid reinforcements. This corresponds to an internal rate of return of about 11.5%. The present value was calculated with a discount rate of 5% actual and a 40-year lifespan. As regards Skagerrak 1-3, history shows that the interconnector, in the same way as NorNed, has been a very good investment from a socioeconomic perspective.

2 CHANGES IN THE TARIFF BASIS

Statnett assumes that the Norwegian part of the investment will be included in the main grid in line with our other interconnectors. It involves that Statnett's permitted revenue is calculated according to the current applicable regulations for financial regulation determined by the NVE (the Norwegian Water Resources and Energy Directorate. Statnett will have a revenue ceiling that is determined so that our revenue over time will cover the costs of operation and depreciation of the systems, as well as provide a reasonable rate of return on invested equity, assuming efficient operations, utilisation and development of the grid. The sum of the revenue ceiling and the costs that can be covered as a supplement to the annual revenue ceiling constitutes our permitted revenue. Permitted revenue for these investments will be calculated in the same manner as for all other investments in Statnett.

Congestion revenues and other trading revenues from the interconnector are considered revenue from sale of a grid service pursuant to NVE's regulations, and the tariffs must be calculated so the grid operation's total actual income over time does not exceed Statnett's permitted revenue. In practice, this means that all congestion revenues and other revenues that arise from the interconnectors are transferred to the users of the Norwegian main grid in the form of lower tariffs than otherwise. Temporary inconsistencies between actual and permitted revenue are balanced out over time pursuant to the higher and lower revenues scheme.

In other words, this means that the main grid customers cover the costs of the interconnectors, and they reap the benefits from all the direct revenues. A corresponding model applies for all interconnectors from Norway, and, overall, this arrangement has contributed to reduce the main grid tariff in Norway over time.

Changes in the tariff basis could be explained with a basis in the difference between Statnett's permitted revenue and the sum of the nominal trading revenues that occur over time. We have not taken into account in our simplified analyses that both the trading revenues and permitted revenue will fluctuate from year to year. The congestion revenues from day-ahead trading are particularly volatile. Furthermore, exchange rate development and the nominal growth in the trading revenues will be significant. Our calculations assume that the nominal operating revenues will increase by 2.5% annually. Permitted revenue will also show greater variation than indicated by the calculations, as a result of changes in interest rates, power prices, etc. Over time this will be detected in annual changes in Statnett's higher and lower revenues that, over time, will be evened out towards nil. The effects in the figures therefore have a more balanced development than what is the case in reality.

For Germany, the average annual increase in permitted revenue will be about NOK 1 150 million. Permitted revenue is expected to be greatest during the first years following commissioning, and then decline to NOK 1 000 million. The highest annual level of permitted revenue is estimated at NOK 1 300 million. This figure therefore represents the increase in the tariff basis had this been a domestic investment.

An inflation adjustment of the revenue estimates indicates that the average operating revenue in nominal NOK could be about NOK 1 250 million. The inflation adjustment indicates that the profile of the trading revenues increases over time.

Over time, the analyses show that the trading revenues from the cable to Germany are in line with permitted revenue. As a result of the profile of permitted revenue and the trading revenue, the tariff basis will nonetheless increase during the first years. The increase in the tariff basis will be greatest during the first year of operation as there is permitted revenue for one year, but only operating revenues for one month. Statnett has the option of balancing the tariffs over certain years in accordance with applicable rules for rating. In subsequent years, the stylised calculations show an increase of NOK 400-500 million. An increase of NOK 500 million in the tariff basis that is allocated over a power consumption of 130 TWh generates an average increase of NOK 0.04/kWh. This cost declines over time, and will gradually become revenue; in our calculations this takes place after approx. 18 years.

Should the cable interconnector be organised as a separate company that keeps the revenues itself, the tariff effects would likely have been even larger with the current tariff model. However, this depends on which tariff model is used as a basis. If one does not use full cost reflectivity in the sense that the owners of the cable are charged with all costs for the system, such an organisation will always involve an increase in tariffs. This is because extensive costs are triggered in the Norwegian grid that cannot be transferred to the relevant cable company in their entirety, as well as the reduction in congestion revenues from other interconnectors.

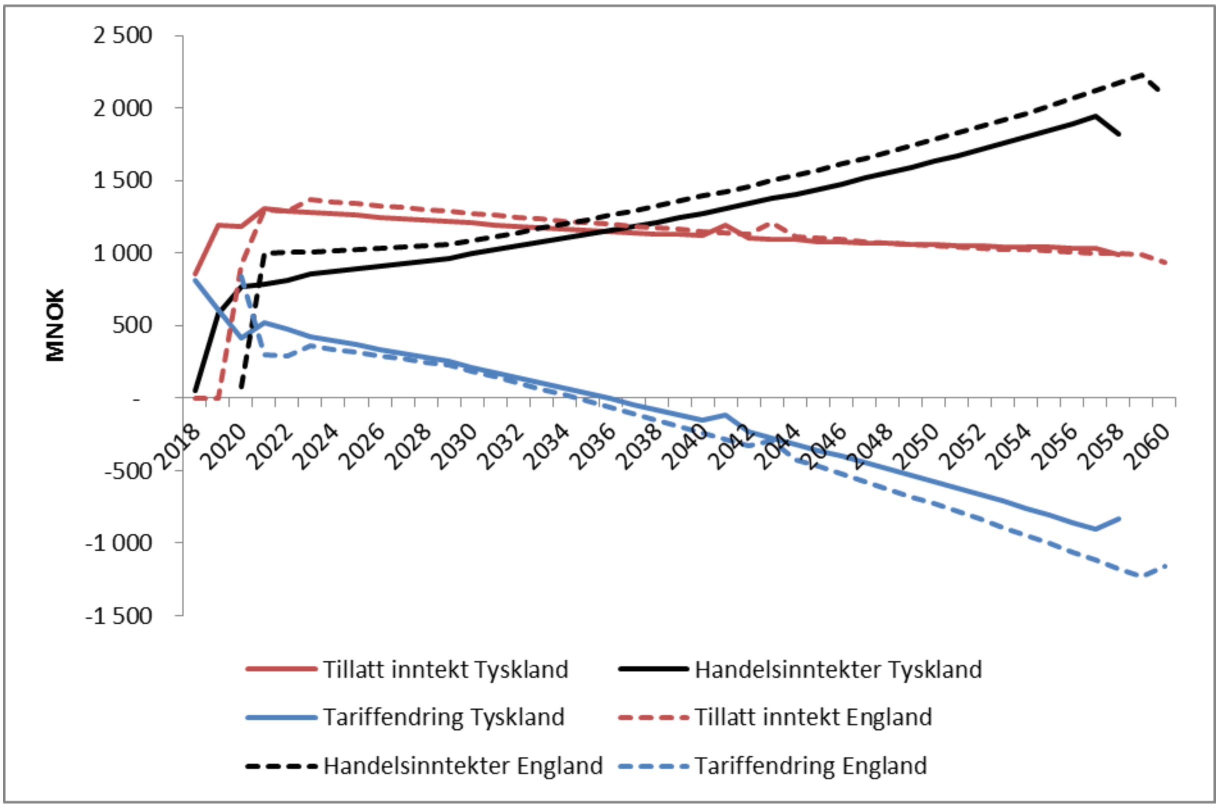


Figure 11: Illustration of the development in permitted revenue and trading revenue for the planned interconnector to Germany and the UK. Values are stated in current million NOK. (Tillatt inntekt = permitted revenue. Tariffendring = tariff change. Handelsinntekt = trading revenue).

For the UK interconnector, the calculated average annual increase in permitted revenue is about NOK 1 100 million. Permitted revenue is expected to be greatest during the first years following commissioning, and then decline to NOK 1 000 million. The highest annual level of permitted revenue is estimated at NOK 1 400 million. This level therefore represents the increase in the tariff basis had this been a domestic investment without direct trading revenues.

An inflation adjustment of our benefit estimates indicates that average operating revenue in nominal kroner could be more than NOK 1 450 million. The inflation adjustment indicates that the profile of the operating revenues will increase over time.

The analyses show that the trading revenues from the UK cable will exceed permitted revenue over time. As a result of the profile of permitted revenue and the trading revenue, the tariff basis will nonetheless increase during the first years. The greatest increase in the tariff basis will occur in the very first year of operation, since there is permitted revenue for one year, but only trading revenues for one month. Statnett has the option of balancing the tariffs over certain years in accordance with applicable rules for rating. In subsequent years, the stylised calculations show an increase of less than NOK 400 million. An increase in the tariff basis of NOK 400 million that is allocated over 130 TWh results in an average increase of NOK 0.03/kWh. The reduction in the tariff basis will only come after 15 years.

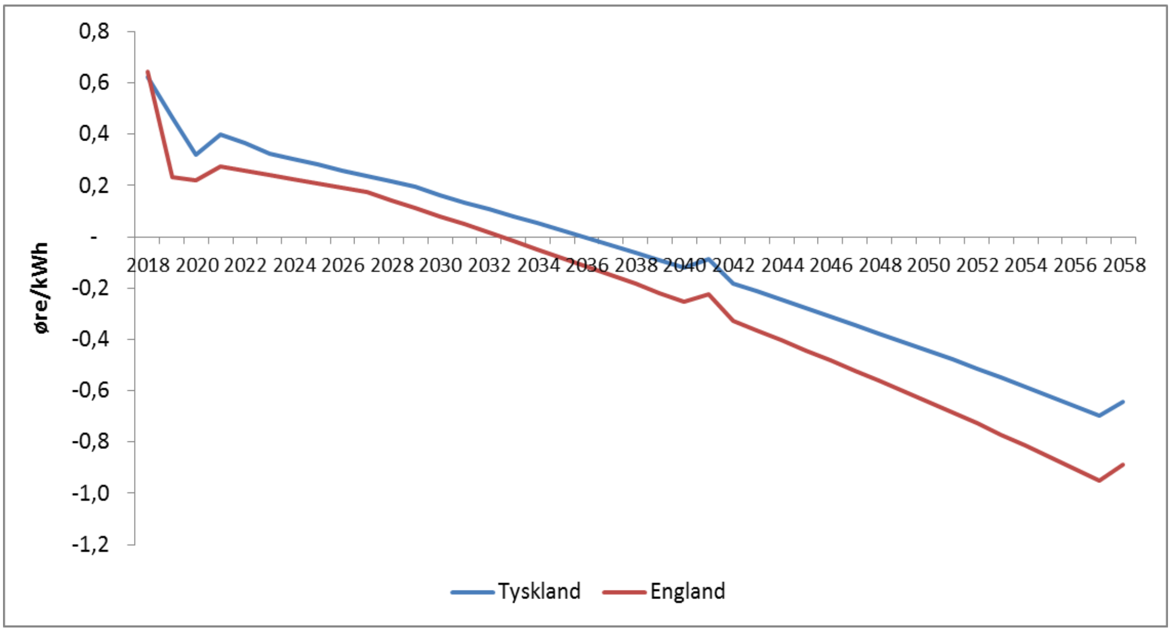


Figure 12: Illustration of change in average tariff per kWh (not distributed by customer groups). The calculations assume a total Norwegian power consumption of 130 TWh which does not vary over the analysis period.

The above calculations are isolated calculations. The total tariff effects of our direct-current interconnectors will most likely be better than what the illustration shows. This is explained by the fact that the other direct-current interconnectors, at the relevant times, are expected to have positive tariff effects in the sense that they contribute to lower tariffs than if the cables were not there.

In Figure 13 the correlations are illustrated graphically. Norway currently has direct-current interconnectors to Denmark and the Netherlands. In addition, three new direct-current interconnectors are expected to become operational by the end of 2020. In the illustration we have chosen to use the principle that the existing cables will first repay themselves. They will then contribute to reduced tariffs for the new ones. Repayment means that the trading revenues will exceed the costs. Revenues from after the interconnectors have been paid off will, based on this principle, contribute directly to repayment of other interconnectors. SK 1-3 were paid off a long time ago through congestion revenues exceeding the costs. Correspondingly, NorNed could be repaid to the customers in the main grid over the course of 2016 if the current level of revenues continues. Based on the decision basis from SK4 this project could already have positive tariff effects from start-up in December 2014. Accumulated over the past few years, the illustrations show that trading revenues from direct-current interconnectors have had a positive tariff effect for the customers in the main grid.

When the cable to Germany is commissioned, Statnett's permitted revenue will increase considerably, though it will take place at the end of the year. However, it could be balanced out in relation to the current tariff regulations so the customers in the main grid will have a more stable tariff. Until commissioning of the UK cable in 2020, the negative tariff effects from the Germany cable will be counteracted by positive contributions from the other direct-current interconnectors, so the net effect for the tariffs will be better than what the Germany cable alone would indicate. When the UK cable is commissioned in 2020, the permitted revenue will increase again, and the increase in the tariff basis will even out over several years vis-à-vis the customers in the main grid if desirable. After this, the changes in the tariff basis are expected to gradually improve and relatively quickly turn back into an overall positive effect. Statnett will continuously evaluate and further develop applicable tariff strategies.

Overall, the tariff effects of all the direct-current interconnectors from Norway are considered positive, and for the two planned interconnectors, seen in isolation, as minor.

Statnett

Statnett's general plans for grid investments will lead to a considerable increase in the grid tariff in the coming decade. Compared with the domestic grid investments, the interconnectors have a very minor impact on the tariffs. This is because trading via the direct-current interconnectors generates considerable direct revenues which the main grid customers benefit from.

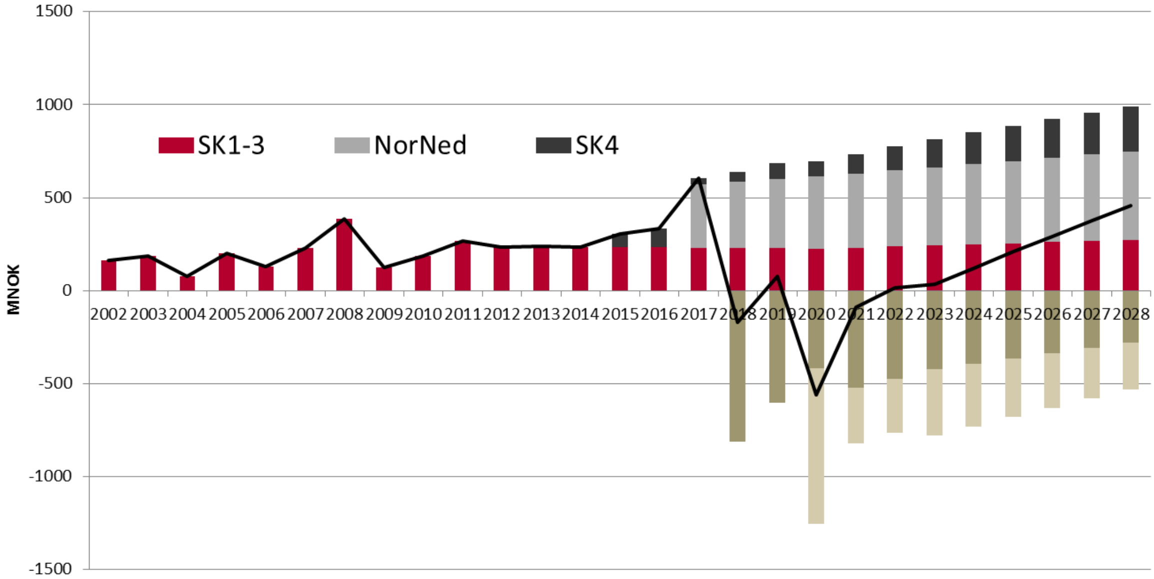


Figure 13: Illustration of the development of total tariff effects of direct-current interconnectors. Values are illustrative and stated in nominal million NOK.

3 GRID REINFORCEMENTS AND SYSTEM OPERATIONS

3.1 Power production and flow of electricity

3.1.1 Power producers' adaptation

All regions in Norway and Sweden have sufficient capacity in their hydro-electric power plants to increase the regulation somewhat during the daytime and reduce regulation at night. However, our simulations show that, with the current grid, increased cable capacity results in the largest production adaptation in southern Norway, and particularly in South-Western Norway. This is because the hydropower in this region is best able to adapt, and that various limitations in the Norwegian-Swedish main grid hinder the possibilities for major adaptations further north.

In a situation with internal bottlenecks vis-à-vis the northern parts of Norway and Sweden, the change in production will be greatest in the region where the interconnectors are connected. However, if there is sufficient capacity internally in Norway and Sweden, the price will be changed in all price areas so the adaptation is distributed to all available hydro-electric power plants. Reservoir size, water inflow and generator capacity will then determine the contribution, not geographic location. The result will be that the hydropower in northern Norway and northern Sweden will also change the allocation. This results in pumping up and down through the entire system with associated flow changes.

Our assessment is that more interconnectors will not significantly change the reservoir allocation. This is caused by strong underlying natural effects, as well as the fact that the imported price structure from the systems we will connect to is not much different from the current price structure.

We primarily see two effects of more interconnectors in connection with reservoir water levels: that the production becomes more balanced throughout the year and that the hydropower values become less extreme for high and low reservoir water levels. Even though the effects pull in slightly different directions, it is our assessment that the total effect will make the reservoir water levels more even throughout the year. This involves lower reservoir water levels at the beginning of winter, and higher reservoir water levels before the spring floods. The most powerful impact on reservoir water levels, water inflow and temperature will remain the same with more interconnectors. The scope of the change in reservoir allocation solely from development of more interconnectors is therefore limited.

The power producers will adapt to greater power trading capacity by increasing the regulated hydropower production in export situations.

If all hydro-electric power plants were located near the connection points for the cables, increased power trading capacity would result in minor changes in the flow pattern in the main grid. However, since the hydro-electric power plants are spread all across Norway, and there is also considerable hydropower production capacity in northern Sweden, the adaptation will be distributed in all hydropower areas. The consequence will be increased flow to the cables' connection points also from the northernmost power stations in both countries.

The assumption for a distributed adaptation is that the capacity in the Norwegian-Swedish main grids is upgraded so no permanent bottlenecks occur.

3.1.2 Power flow

Typical power flow in Norway and Sweden

Much of the consumption in eastern Norway is covered by hydropower from western Norway. This creates flow from west to east in southern Norway.

The power deficit in central Norway is covered by the surplus in Nordland and northern Sweden. This results in almost continuous southbound flow from Nordland to central Norway.

There is currently only one weak interconnector between central Norway and southern Norway. Most of the flow from north to south therefore passes through Sweden.

The majority of the Swedish consumption takes place in the large cities in the south. The power production in this area is mainly based on nuclear power. These power stations have a regular daily production that is large enough to cover the regional consumption at night. During the day, Swedish and partially Norwegian hydro power cover most of the peak load. The result is a permanent flow pattern with considerable flow from north to south in Sweden during the day. The power also flows towards the south at night, but the volume is much smaller than during the day.

Power trading via the interconnectors also helps determine the flow pattern. With the current relatively modest transmission capacity, the effect is greatest near the connection points for the cables, to the very south in Norway and Sweden. For Norway, the main rule is import of power at night and export during the day. The strain on the Nordic power grid is greater during export than in import situations. This is because the flow caused by export, simply put, goes in the same direction as the other power flow. Import situations result in flow from the west to east in southern Norway, i.e. in the same direction as the other power flow. However, in the rest of the Nordic region, import situations result in the opposite flow, which is often amplified by lower production in these situations than during export.

Changes in the power flow in central and northern Norway

Even with the grid reinforcements in Statnett's grid development plan, there will be many limitations in the grid in 2020. Among other factors, bottlenecks out of northern Norway will prevent the hydro-electric power plants in this part of the country from delivering the flexibility the cables will require. We thus do not expect considerable changes in the flow between central and southern Norway as a result of increased cable capacity.

Changes in the power flow in southern Norway

A cable connected to the grid at Kvilldal will increase the power flow from Samnanger and southwards towards the connection point.

With a moderate increase in new electricity production in central Norway and bottlenecks in northern Norway, we are not expecting any significant bottlenecks in Gudbrandsdalen in 2020.

Changes in the power flow between southern Norway and Sweden

We anticipate reduced transmission from southern Norway to southern Sweden in export situations, and increased transmission in import situations. The reason for this is that we have assumed that certain upgrades will take place in the Swedish grid, which will make it possible for Swedish hydro-electric power plants to contribute to and cover the export on the cables from Norway. The expected strengthening of the Swedish-Finnish energy balance will also increase flow towards Norway. Much of the increased flow is expected to take place via Hasle. It will be possible to handle any bottlenecks with price areas in the same way as today.

3.2 Grid conditions - Norway

The Southern Norway study (2011) describes the grid reinforcements necessary to run two new interconnectors without significant capacity restrictions. We have chosen to divide the projects into three packages:

1. The Southern Norway Package (Eastern Corridor and Western Corridor, Step 1)
2. The Basic Package (Sogndal – Aurland and Evanger – Samnanger)
3. The Cable Package (Western Corridor, Step 2 and 3 and Sauda – Samnanger)

Below follows a brief status and description of the grid reinforcement projects. We also describe the principles for cost allocation for domestic grid reinforcements and how we have applied these to the cable projects.

3.2.1 *Grid reinforcement projects*

Below follows a description and status of the grid reinforcements relevant for the interconnectors. Until the grid reinforcement projects have been completed, the upgrade work may result in situations which will restrict utilisation of the trading capacity on the planned cables temporarily due to outages in the domestic grid. If transmission capacity limitations occur in the domestic grid Statnett must, as Transmission System Operator, have the option to adjust the use of the available cable capacity to the situation. We take this into account in our socioeconomic analyses by reducing the expected revenues from the planned interconnectors accordingly. The benefit of commissioning the new interconnectors as early as possible is so substantial that even though operating flexibility carries a cost, the total benefit will still be positive for Norwegian society.

Western Corridor

The Western Corridor is the name of the main grid between Kristiansand and Sauda. This is an important corridor supplying large amounts of production to the grid, and transmitting power to and from the landing sites for the interconnectors in Feda and Kristiansand.

The corridor mainly consists of 300 kV parallel power lines. To increase capacity Statnett is planning to upgrade the grid voltage from Kristiansand to Sauda to 420 kV. Grid upgrades entail that existing 300 kV power lines in the main grid are remodelled so they can operate at 420 kV voltage. In order to upgrade the voltage the substations at either end of the power line must be upgraded so that the power line can be connected to 420 kV voltage facilities. The combined voltage and temperature upgrade will increase capacity by up to 80 per cent.

Statnett is planning a step-by-step development, see below for a more detailed description, where the most important restrictions are improved first. In practice, the steps will overlap somewhat, and progress will depend on when the final licences are granted.

Step 1

Provides opportunities for increased renewable production in southern and western Norway and necessary capacity for future grid upgrades and modifications. Step 1 is a precondition for connection of new interconnectors to the Norwegian grid.

- Voltage upgrade to establish one 420 kV interconnector between Kristiansand–Feda–Saurdal–Sauda, thus ensuring a rapid increase in capacity in the corridor. The upgrade involves construction of a new 420 kV-power line from Lyse via Tonstad to Feda where the existing power line will subsequently be demolished, as well as re-insulation of the existing power line between Lyse and Saurdal and one of the two power lines between Tonstad and Feda.
- The power lines Lyse–Duge and Tonstad (Ertsmyra)–Solhom will be upgraded to three-bundle conductors. . This entails new construction and subsequently demolition of the existing simplex power line. The power lines between Solhom and Arendal will be re-insulated but will still operate at 300 kV.
- Upgrade the substations in Sauda, Saurdal, Lyse, Tjørhom, and Kristiansand and establish Ertsmyra substation at Tonstad and Kvinesdal substation at Feda.

Step 2

Step 2 facilitates increased renewable production in western Norway and makes it possible to establish an international interconnector with a connection point in Kvilldal. Step 2 entails an upgrade of power line no. 2 between Lyse-Sauda.

- Upgrade of power line no. 2 between Lyse and Sauda.
- Completing the 420kV facilities in Sauda.

Step 3

This upgrade provides an opportunity for free use of the Germany cable from Tonstad or Feda. Time wise, there is not much distinguishing completion of Step 3 from Step 2:

- Increasing the voltage on the Ertsmyra–Solhom–Arendal section by establishing a new substation in Solhom.
- It is assumed that a new 420 kV power line between Lyse–Stølaheia will be the solution for reinforcement in southern Rogaland. The cost of this interconnector has not been included. Work on this project is on-going under the direction of Lyse Sentralnett AS.

The Western Corridor is currently expected to be completed before the UK cable enters service in December 2020, whereas some work will still be on-going when the Germany cable enters operation in December 2018. According to the current progress plans, Step 2 and Lyse–Støleheia will be complete in 2019, whereas Step 3 will be complete in 2020.

Full utilisation of the planned interconnectors' trading capacity cannot be expected before the work on the Western Corridor is complete. In principle, consequences of the reduced capacity will be reduced congestion revenues from the cable in question, increased congestion revenues from other cables, reduced transmission loss and reduction in net consumer and producer surplus. Moreover, an increase in the power flow when the cables enter operation may cause bottlenecks further north in the Norwegian transmission grid.

Our simulations, where we assume that the rest of the grid is intact, indicate that there will be relatively few net socioeconomic consequences of the trading capacity not being fully utilised from the beginning. The calculations assume that the Sauda – Lyse section will not be complete until the beginning of 2020. This has an overall negative effect on the revenues corresponding to approx. EUR 7 million. In addition, the simulations indicate that increased power flow in the cables can create a bottleneck north of Sauda (ref. description of Sauda – Samnanger below).

Statnett can adjust the activity and measures in the Western Corridor to the progress of the Germany project. The cost estimates for Steps 2 and 3 already include this uncertainty. With planned shutdowns that cannot be avoided in 2018 and 2019, or if the grid is not intact for other reasons, the financial consequences could be greater. In these situations one must compare the value of utilising the capacity against the costs of having the capacity available. We therefore did not further reduce the profitability of the projects in our calculations to take into consideration such possible situations.

Eastern Corridor

The Eastern Corridor project comprises an upgrade of the existing 300 kV power line to 420 kV between Kristiansand and Bamble (approx. 140 km) and expansion/upgrade of the current transformer stations in Kristiansand and Arendal. Moreover, the project involves construction of an approximately 38-kilometre long 420 kV power line, demolition of 57 kilometres of existing power lines, two new transformer stations (Bamble and Grenland) and less extensive expansions of Rød station and Skagerak Nett's station at Voll.

The need for the Eastern Corridor has been strengthened since the initial concept decision. The measure is an important precondition for realisation of the substantial socioeconomic benefits of connecting the interconnectors to the grid. Upgrading the Eastern Corridor will also help improve security of supply in Eastern Norway, by increasing capacity. The increased transformation towards the regional grid in Telemark will improve security of supply in this area, and allow for demolition of lower voltage power lines.

Commissioning is scheduled to start by 31 December 2014. Statnett has obtained all licences and construction has started.

Status voltage upgrades Kristiansand – Bamble

The re-insulation of the power line from Kristiansand to Bamble is proceeding well. Construction of the power line entries to the Arendal and Kristiansand transformer stations has also started. In Arendal the access road has been completed and the suppliers of the total package have started the groundwork on the site. In Kristiansand the groundwork is completed and work has started on the foundations. All the major contracts have been signed for Kristiansand – Bamble. The Environment, Transport and Construction Plan (ETCP) has been approved by the NVE. Work is on-going to establish the required agreements with property owners and other grid companies.

Status of the new 420 kV power line between Bamble and Rød

Tenders have been received for the power line contract. For the substations, tenders have been received for the road and groundwork as well as for the total package for Grenland and Bamble transformer stations. For transformers and reactors, the deadline for entering into options is 1 April 2013.

Sauda - Samnanger

Up to 2020, we expect an increased north-south flow in the grid in Western Norway due to increased development of new renewable production and more interconnectors from Southern Norway. This triggers a need to reinforce the grid in the area from Sauda in the south to Samnanger in the north. In the long term, we also expect that the grid further north towards Sogndal will have to be upgraded.

A reinforcement northwards from Sauda would be a natural continuation of the voltage upgrade in the Western Corridor. Together with Sima-Samnanger, this will provide a strong grid from Feda in the south to Hallingdal. The new Ørskog-Sogndal interconnector will, together with the new 420 kV Sogndal-Aurland power line, connect the grid in Hallingdal to the grid in Møre. In this way, reinforcing the grid between Sauda and Samnanger will be an important part of what will become a strong continuous grid connection between southern Norway, western Norway and central Norway.

Statnett is working on the concept choice assessment for upgrade of the main grid between Sauda and Samnanger in close cooperation with BKK and SLIDE. According to the plan, a concept choice will be made in the third quarter of 2013. At this date, we find that, in accordance with the MPE's proposal for new regulations relating to concept choice studies and external quality assurance of major power line cases, the upgrade between Sauda and Samnanger is not considered a "major power line case", and will therefore follow the ordinary licensing process. According to Statnett's investment plan for 2012 the interconnector will be upgraded between 2020 and 2022.

3.2.2 Cost allocation principles for the domestic grid

Statnett will develop the portfolio of grid facilities that will maximise total socioeconomic surplus.

In our socioeconomic calculations of the interconnectors we must therefore review how much the domestic grid costs will change if we build the interconnectors and prepare the domestic grid for optimal utilisation of the investments. The cost allocation principles can be summed up as follows:

1. When there is spare capacity in the grid, now and in the future, the use of this capacity is cost-free. This is because there will be no change in the cost of these facilities if we build the interconnectors, nor will there be any other cost changes, except for transmission loss and an increase in system operation costs, which is described elsewhere in the application.
2. New facilities and the domestic benefit will be greater than the cost of investment. At the same time there will be spare capacity in the grid after the investment. In this case, the new facility will be built regardless of whether or not new interconnectors are constructed, and the costs of the new facility will therefore not affect the investment decision for the interconnector.
3. If the power flow from one interconnector displaces other use of the existing grid, now or sometime in the future, the present value of the expected lost benefit must be included as an anticipated cost.
4. Triggers a domestic grid investment when the investment is profitable if the interconnector is built, but not profitable without the interconnector. In this case, the increase in costs will be allocated to the interconnector due to the capacity expansion less the use for domestic purposes. Other benefits will arise

as the increase in grid capacity will also cover domestic needs, such as improved security of supply. A special element of this principle is that the domestic capacity expansion will only benefit the interconnector. In this case, the total cost of the grid reinforcement will be charged to the interconnector.

5. There are situations where the grid must be expanded irrespective of domestic needs, but where more capacity or earlier reinforcement will be chosen on account of the interconnector. If the capacity increase only serves the interconnector and has no other useful effects, the entire cost increase must be attributed to the interconnector. If the increased capacity only serves the interconnector and has no other benefits, the entire cost increase must be attributed to the interconnector. If the expansion also has other benefits, these must be deducted from the cost basis for the interconnector. This is merely another version of the principle stating that the net cost increase must be attributed to the interconnector.

3.2.3 Cost allocation in the domestic grid

Estimates of net capacity costs generated by the two planned interconnectors in the domestic grid are shown in the right-hand column in the table below. The estimates are based on the principles described above and assume that the Germany interconnector enters operation before the UK interconnector.

The Southern Norway Package and *the Basic Package* consist of projects that are necessary for the interconnectors, but are also driven by, and useful for, other purposes. With the exception of the initial step of the Western Corridor it will be socioeconomically profitable to implement the above-mentioned projects and the Lyse – Stølaheia power line regardless of whether the interconnectors are constructed. These grid reinforcements will be implemented in any case, and the costs should therefore not be included in the profitability calculation of the interconnectors.

The initial step of the Western Corridor would not be profitable in isolation. Without the interconnectors it would in this case be more profitable to choose a less expensive solution. The increase in scope in Step 1 relating to facilitation for further upgrades must be included in the net cost of the interconnectors. However, parts of this increase in scope are forced reinvestment. This then pulls in the opposite direction. When taking into account the forced reinvestment, the net cost that will be charged to the interconnectors is about NOK 1 billion.

The cable package also consists of measures that are necessary for the interconnectors. Unlike the other two packages, these are primarily driven by the need for capacity for the interconnectors. The grid reinforcements have a certain domestic benefit, but are not profitable without the interconnectors. These projects would therefore not have been realised independently. As a consequence of this, the costs will be included in the profitability calculation of the international interconnector. However, parts of this increase in capacity are forced reinvestment, and there are also some domestic useful effects. This then pulls in the opposite direction. Taking into account the forced reinvestments and useful effects the net cost amounts to approximately NOK 2.5 billion. This will be included in the cost of the interconnectors.

After the packages have been realised, there will still be spare capacity. The interconnectors will therefore not supplant other profitable projects. The spare capacity has a value (real option) as it provides the possibility of increased use of the grid in the future, for example for more renewable power, new industry or further increases in power trading capacity. The value of the real option reduces the cost that will be attributed to the interconnectors. at this time, it is uncertain how much spare capacity there will be, and it is of course difficult to predict what transmission needs we will have in the future. Consequently, it is also difficult to estimate how much the real option is worth. We have therefore chosen not to put a figure on the option value at this time.

For the German interconnector, which will be connected at Tonstad, the Western Corridor will have to be extended to a full package. *Net costs charged to the German interconnector total NOK 2 billion.* The measures entail:

- Voltage upgrade of the Sauda-Lyse section, 300 kV operation (alternative 2 in KVU for the Western Corridor)
- New Solhom substation and 420 kV operation on the Ertsmyra-Solhom-Arendal section

- New power line between Lyse and Stølaheia or a new 420 kV power line in Dugeringen in parallel with the existing line

For the UK interconnector, which will be connected at Kvilldal, voltage upgrades will be necessary on the section from Sauda to Samnanger. *Net cost charged to the UK interconnector is NOK 1.5 billion.*

Package	**Grid reinforcements**	**Total cost [billion NOK]**	**Net cost [billion NOK]**
The Southern Norway Package	**Eastern Corridor**	**1.5**	**0**
	Western Corridor (Step 1)	**5**	**1**
The Basic Package	**Sogndal – Aurland**	**0.5**	**0**
	Evanger – Samnanger	**0.2**	**0**
The Cable Package	**Western Corridor (Step 2)**	**1.5**	**0.7**
	Western Corridor (Step 3)	**0.5**	**0.3**
	Sauda – Samnanger	**2**	**1.5**
	Lyse – Stølaheia	**2**	**0**
Total cost		**13.2**	**3.5**

Table 12: Need for grid reinforcements as identified in the Southern Norway Study. The share that will be charged to the interconnectors (net cost) based on the principles described above (all figures in fixed 2012 NOK rounded off to the nearest NOK 100 million).

3.3 Grid conditions - Germany

3.3.1 Status and plans, local projects

The current local power grid in the Wilster/Hamburg area is not expected to have enough capacity to handle future transmission volumes from local power production and the interconnector from Norway. For the cable interconnector there will be restrictions on some power lines, notably between Büttel, Wilster and Hamburg and further south across Elben towards Dollern and eastwards towards Krümmel. For optimal use of the interconnector, it will be necessary to reinforce or upgrade these power lines. The most critical upgrades have been included in the German grid development plan for the coming decade (Netzentwicklungsplan 2012/2013, "NEP"), and are expected to be completed gradually during the period 2014 to 2022. The construction of HVDC interconnectors southwards from Wilster may change the need for local upgrades, see below for more details.

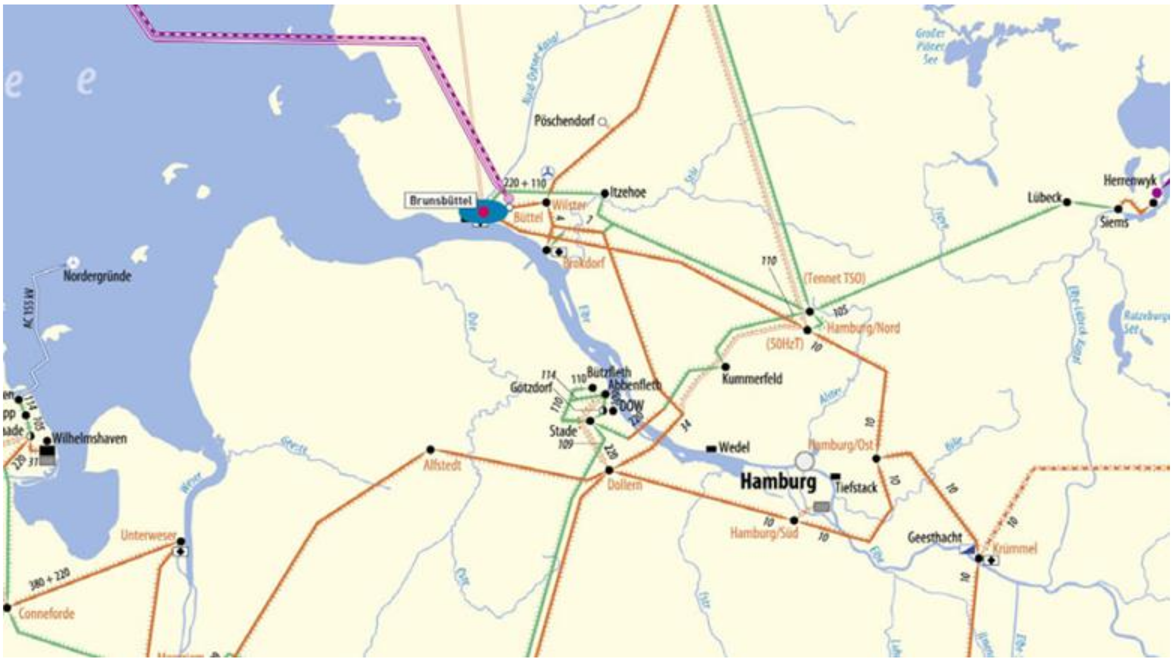


Figure 14: General map of the power grid in the Hamburg area. The thick purple line shows the Germany cable.

3.3.2 Status and plans, national projects

The German power system is characterised by large-scale production in the north and heavy consumption in the south, with a corresponding need for power transmission between the regions. Due to insufficient transmission capacity there are currently bottlenecks at a regional and national level between the north and the south. In the years ahead, development of more renewable power in the north, particularly wind power, and phase-out of nuclear power in the south, will further increase the need for power transmission from the north to consumption centres in the south and west.

As a consequence of this, major national grid reinforcements are planned for the period leading up to 2022 involving investments in the region of EUR 21 billion, as described in the NEP, and towards 2032. Such reinforcements include construction of direct HVAC and HVDC interconnectors between the north and the south, with a total capacity of 10 GW. Corridor C is most relevant for the cable interconnector (see Figure 15) which will consist of three interconnectors going south from the Hamburg area, totalling 3 900 MW. These will be connected to the grid at Brunsbüttel (5), Wilster (6) and Kaltenkirchen (7) respectively. The interconnector from Brunsbüttel is scheduled to enter operation between 2020 and 2022, the interconnector from Wilster between 2018 and 2019, and the interconnector from Kaltenkirchen between 2017 and 2019.

When the planned grid reinforcements and the new HVDC interconnectors have been completed in 2022, we do not expect any restrictions on the use of the interconnector as a result of grid restrictions on the German side. Until then, bottlenecks may occur both locally and regionally which may affect power trading.

Figure 15: General map of planned HVDC interconnectors in the Hamburg area. 5 = Brunsbüttel, 6 = Wilster, 7 = Kaltenkirchen

3.4 Grid conditions – the UK

The British main grid will undergo major reinforcements, both onshore and offshore, to ensure that there is sufficient capacity to handle the large volumes of new renewable power generation which will need grid connection and market access in the years ahead.

The process of allocating connection points for connection of interconnectors in the British national grid is managed by the British TSO National Grid Electricity Transmission ("NGET»). In addition to handling the national regulations for such grid connections, NGET has, since 2012, also had to comply with directives and provisions of the Third Energy Package. According to this, interconnectors must now be considered transmission grids, and the holder of a so-called interconnector licence be certified as a Transmission System Owner».

In accordance with the Third Energy Package, NGET as the national TSO, NSN Link as the project developer and Transmission System Owner and Statnett as the joint project developer and «remote Transmission System Operator», must coordinate and cooperate regarding the design of the international interconnector and how it will interact with the national transmission grid. The Third Package also assumes that investments in the main grid that are necessary in order to remove bottlenecks that prevent full utilisation of the capacity in the interconnectors, will be made. Based on this foundation, NGET offers project developers a «Construction Agreement» and a «Bilateral Connection Agreement» («BCA»).

Within the framework of the BCA, the interconnector is allocated firm capacity, both for import and export. If an interconnector is connected to the grid before the planned domestic grid reinforcements have been carried out, capacity on the interconnector can be restricted until the required grid reinforcements have taken place.

The UK project has been awarded a BCA which is in accordance with the scheduled start of operations. The connection point at the transformer station in Blyth was chosen after cooperation and coordination between NGIL, NGET and Statnett. One important criterion for the choice was to find an optimal connection point, bearing in mind that the necessary grid reinforcements should make it possible to guarantee that the 1400 MW capacity can be fully exploited, for import as well as for export.

In principle, the right to firm capacity is perpetual. However, under particularly demanding operating conditions, or should unforeseen incidents arise, the transmission system operator is entitled to restrict the flow on the cable. In the event of more long-term needs, the system operator may negotiate the right to restrict the flow on commercial terms.

The Third Energy Package specifies that the entire capacity of the interconnectors must be made available to the market players, and that the TSOs must not limit the transmission capacity to solve bottleneck issues in their own monitored area. The regulations allow for some exemptions from the main rule. Utilisation of the available capacity of an international interconnector may be limited if necessary due to, for instance:

- «network security standards»
- «keeping the transmission within agreed security limits»
- «complying with safety standards of secure network operation»

3.5 System operations

Below follows a brief description of what impact Statnett expects the combination of more unregulated power production and increased transmission capacity to surrounding systems to have on system operations.

3.5.1 New and increased challenges

We anticipate that more interconnectors will result in greater production variations between day and night. This means that during some periods we will have a situation where most of the reservoir power stations are either operative (daytime) or non-operative (night-time). Both these conditions present new challenges for system operation as access to various types of reserves may be scarce when the power stations are operating on full capacity, as well as when they are non-operative. Mechanisms must therefore be put in place to ensure necessary reserves. Furthermore, the transition between night (full stop) and day will result in greater flow changes in the system with a greater need for automatic reserves. Such an operation pattern will also put stress on electro-technical conditions such as average margins, short-circuit performance, reactive reserves and rotating mass, and is likely to increase special regulation costs. Overall, the new operation pattern will result in a more dynamic situation where we will have situations with a surplus of reserves that can be exported, as well as situations with a shortage of reserves, also to meet domestic needs.

Changes in system operations will result in a need for increased volume reserves, higher system operation costs for the purchase of reserves, as well as a need for new or adjusted solutions.

Reserves

The physics in the power system require there to always be a balance between consumption, power trading and power generation. To maintain the desired system stability, mechanisms must be in place to handle any imbalance. The main instruments for this are reserves. We usually distinguish between three types of reserves: primary, secondary and tertiary. The first two types are automatic, whereas the last type is manual.

Greater changes in power exchange and production will increase the challenge of balancing the system and thus the need for reserves. Larger volumes of both automatic and tertiary reserves will be required.

Automatic reserves

The balancing of power production, consumption and exchange is totally dependent on correct dimensioning and placement of automatic reserves in accordance with the operational situation at hand. We have seen considerable changes in system operations in the last 20 years as market players have adapted more actively to the price signals in the market. Utilisation of the Nordic power system is now much more dynamic than previously. This materialises in greater and more frequent changes in the flow on the international interconnector.

We have estimated the need to increase automatic reserves as a consequence of increased power trading capacity to be around 10% of the interconnector capacity. The cost of purchasing extra reserves has been included in the socioeconomic calculations.

Tertiary reserves

Also in the future, much of the balancing is likely to be based on manual adjustments handled by the transmission system operator. The tools used are the market bids for regulating power (RK, which is a tertiary reserve). There is already a capacity problem in this market for much of the year. In order to meet their obligations, the market players have normally planned to produce so much in the autumn, winter and spring that only limited capacity is available for sale in the RK market. To ensure that there is a sufficient volume in this market, Statnett operates a capacity market (RKOM)where the players are paid to place upward regulation bids; by either ramping up production or driving down consumption. The current volume traded on RKOM is approximately 2000 MW.

Cost of reserves

The cost of reserving capacity for the various reserve markets has two main price drivers. One is reduced generator unit efficiency, the other is alternative use of water.

Automatic reserves

Up until a few years ago, the supply and costs of automatic reserves were relatively moderate. The reason for this was mandatory supplies and limited international sales. In recent years, we have experienced periods where capacity from rotating machinery has been insufficient to supply the volumes of automatic reserves required under the system operation agreement. Consequently, Statnett has established systems to secure access to the required volumes. When the capacity from rotating machinery has been exhausted, suppliers of automatic reserves must reorganise the use of water. The players must ensure that more machinery is up and running to be able to offer a larger volume of with reserves.

Based on historical data, we see that the supply curve for primary reserves shows that a certain volume can be supplied at relatively low prices by setting the droop of rotary machinery. The next segment on the supply curve is players offering to move water between ”day and night” (i.e. within a relatively short time segment). The cost of this is determined by the price difference between day and night during the summer period. We anticipate that this price difference will increase in the period leading up to 2020 and result in higher prices of reserves in this segment in the future. If even higher reserve volumes are needed, this will be supplied by players who offer "winter water" to ensure that rotating machinery supplies automatic reserves in the summer. We also expect that these price differences and thus the reserve costs will increase towards 2020. As the reserve need will increase corresponding to approx. 10% of the capacity of a new cable, Statnett's own increase in demand for reserves will also contribute to higher costs of reserves.

The fact that we are planning to sell reserves to our trade partners will also have an impact. This will be socioeconomically profitable, but will, in isolation, drive up costs for the transmission system operator.

Tertiary reserves

Players offering capacity for upward regulation in RKOM during periods of high production must reduce the use of water during high-price hours. The water must then be used during later periods with potentially lower energy prices. The players will be compensated for this potential loss, where the cost driver is the price difference between the periods. Greater price variations within a 24-hour period and between the seasons contribute to driving the prices in RKOM upwards.

Downward regulation

In recent years, a new phenomenon has emerged where there is limited capacity for downward regulation. During the summer season, low loads combined with high imports and large volumes of unregulated production have resulted in the volume of bids for downward regulation of production reaching a critically low limit. Consequently, a new system is likely to be introduced to secure downward regulation capacity in the summer months corresponding to the current RKOM market which secures upward regulation capacity in winter. The alternative will be to limit transmission capacity on DC interconnectors.

3.5.2 Potential new and adjusted solutions

An increase in the need for reserves and thus higher system operation costs will bring about alternative measures to handle future system operations. There will probably be variations of all the changes we have described. However, they are not likely to be extensive enough to prevent a significant increase in system services costs, only alleviate them somewhat.

Further developing the system of quarterly (15-minute) resolution during the operating hour

The current balancing regulation is based on an hourly resolution in the energy market. To better be able to handle any imbalances that arise within the operating hour, quarterly resolution is required for production plans when the production varies significantly from hour to hour. However, momentary imbalance during the operating hour will still be a problem and discussions are on-going on whether extended quarterly resolution should be introduced. This can take place to a greater or lesser extent. Some alternatives are listed below.

- The most extensive change is introducing quarterly settlement of all imbalances. There are strong indications that such a change would have to be implemented also in the Nordic region sooner or later. This will require quarterly resolution.
- A less extensive variation would be to introduce quarterly resolution only for imbalances between the physical production and plans from larger production units. This can be regarded as a continuation of the two-price-settlement for production
- Quarterly resolution could also be introduced for various market products:
    - Quarterly resolution in all system and balancing services markets. This way, a consistent correlation could be achieved between these markets and the existing quarterly resolution of the production plan.
    - Quarterly resolution in the intraday market. This will give market players the opportunity to achieve balance by trading by the quarter.
    - Quarterly resolution of the day-ahead market. This option may become necessary to achieve sufficient balance per quarter. There are diverging views on whether this is a desirable development.

Combinations of these options may also be possible even if one would like to keep the hourly resolution in the day-ahead market. Such changes could reduce ramping imbalances significantly. The main reason for this is that the structural imbalances would be reduced. Such a solution would incur costs, primarily relating to new measuring equipment and new measuring systems. However, these costs cannot be attributed solely to the individual new cable interconnector.

Increase the volume of automatic reserves

Challenges relating to rapid changes in flow are currently managed through ramping restrictions on DC interconnectors, but also through automatic reserves. It is possible to change the "mixing ratio" between the two measures. In other words, we can adjust the ramping restrictions if we increase the volume of automatic reserves. Increasing the volume of automatic reserves would entail two types of socioeconomic costs:

- Effect capacity is not included in the energy market. New interconnectors could mean that the unit costs of this could be significantly higher than they are today.
- Unit efficiency would be reduced. It would be necessary to run several units concurrently to achieve sufficient output quickly enough. This means that the set point would be less than the optimal point.

In this case, the water would be reorganised by perhaps implementing a different plan than the original one.

Implement a more detailed plan for production changes

Requirements may be introduced relating to plans and/or automatic control which would entail better scheduled changes in the production level of the units, thus reducing anticipated imbalances. A more even increase in production can be achieved by:

- Changing the production level of the various units at slightly different times. This could be done by, for instance, increasing the production for some units five minutes before the new hour, some four minutes before, etc. This is a variant of the quarterly move, but with a finer time resolution. The disadvantage of this alternative is that we may have less optimal adaptation to the planned change. This will depend on the number of units that must change their production level. This system is also challenging from an administrative standpoint.
- Increase the set point in each generator in multiple, small steps instead of only increasing the set point once. It could for instance be adjusted ten times during the ten minutes permitted under the UCTE rules.
- Adjust the unit production in accordance with changes in the flow on the cables. This is in fact an LFC solution where changes in the cable flow are input signals to AGC on the units. Regulating power could also be used here.
- Further develop the ramping restrictions for major production changes.

Introduce more flexible ENTSO-E rules and EU Codes

With the current market design, slower regulation of the HVDC output would increase the imbalance counter trade that would consequently occur between the Continent and the Nordic region in an unfavourable direction in terms of price differences in the energy market. However, this does not constitute a socioeconomic cost, but a redistribution of income where the TSOs must pay more.

However, plans are currently being considered to enable ramping during the whole hour when changes in flow occur on interconnectors. This way we would be able to reduce ramping restrictions on interconnectors and be able to reverse flow on the cables more quickly. This will also be in line with the preferences of the market.

Summary and conclusion

Overall, the described measures will entail that we will be able to handle more ramping on the HVDC interconnectors. However, this will result in greater changes in production for some hour shifts due to greater cable flow changes. To maintain operational reliability in the system it will therefore be necessary to increase the volume of automatic reserves and further develop the system of quarterly (15 minute) production plans.

There are currently many interconnectors linking the synchronous system to surrounding areas. Intraday trading is possible for most of these interconnectors and for all of them it is possible for the TSOs to trade tertiary reserves under difficult system operation conditions. More interconnectors to various areas will increase the opportunity to draw on flexibility and reserves from other systems. Currently, the greatest focus is on how to facilitate energy trading via interconnectors. There has been less focus on the impact on system operations and the need for more flexible system operations. A better balance should be struck between these two considerations as this could alleviate the need for back-up capacity reservations.

The presentation of prices and reserve volumes above is based on the current solutions where reservoir power stations are the main providers of inexpensive flexible reserves. Technologically it is, however, possible for wind farms, run-of-river power plants and small-scale power stations to supply automatic and tertiary reserves. Such deliveries are not the cheapest, but will be able to compete with reservoir power stations when we have to draw on units using "winter water". These deliveries are not suitable for all units. However, there is most likely a significant volume that will be able to contribute more flexibility than what is currently the case. In order to realise the new opportunities, tools must be developed that will highlight the regulation opportunities and the cost of these.

4 ORGANISATION OF THE GERMAN POWER SECTOR AND POWER MARKET

4.1 Power system and balance

Germany has the largest power market in Europe. Due to its geographical location, the German power system is connected to nine surrounding systems. Considerable power trading takes place over these connections, which can be illustrated by the fact that Germany is the largest importer (ahead of Italy) and the second largest exporter (after France) of power in Europe.

Thermal power stations that burn fossil fuels represent nearly 60% of power production. Nuclear power contributes just under 20% and new renewable production contributed 20% in 2011. In 2011, Germany had an installed capacity of 168 000 MW. The country has experienced rapid growth in wind and solar power in recent years, and is now responsible for about half of the installed wind power production capacity and one-third of the solar power production capacity in the EU.

Consumption in 2011 was 541 TWh. A consumption record of 87 500 MW was registered in 2010. Industry represents about half of the consumption. The other half is relatively evenly distributed between households and other commercial activities, as well as the public sector.

The decision to immediately close eight nuclear power reactors in the aftermath of the Fukushima accident, combined with the major production fluctuations that are caused by the rapidly growing number of renewable production facilities, has made it very challenging to balance the system in the past few winters. In particular, the production margins in southern Germany are inadequate. Shutting down 5000 MW of nuclear power and inadequate transmission capacity to Northern Germany has forced the Germans to purchase back-up capacity from Austria. The German government has proposed a legal amendment that allows for stopping the plans to shut down gas fired power stations that are not profitable if the regulator determines that they are critical for the system. The programme is temporary, and will be terminated no later than in 2019.

4.2 Gesetz für den Vorrang Erneuerbarer Energien ("EEG")

The act, which was introduced in 2000 and has been amended several times when required, forms the basis for the renewable initiatives in Germany. The key policy instrument has been power transport tariffs. The German transmission system operators (TSOs) have a legal obligation to connect all new renewable power production to the grid and to purchase all the power they produce for 20 years at a guaranteed price. This subsidy scheme eliminates both the price and volume risk for the investors and has proven to be a highly efficient instrument for establishing a large number of renewable power production facilities in a short time. Initially, it is the TSOs who pay the power producers, but they will in turn invoice the consumers.

4.3 Market structure and ownership

The players in the German power market can be categorised into four groups:

- The four major energy companies – RWE, E.ON, EnBW and Vattenfall – that own about 60% of the production capacity, supply regional and local suppliers, in addition to end users.
- About sixty major regional energy companies that supply end users with power, mainly outside the major cities.
- More than a thousand local energy companies, called "Stadtwerke" and small regional energy companies that are often owned by the municipality. They deliver power, gas, water, district heating and public transportation in their respective districts and cities.
- Energy companies from other European countries, for example Statkraft and GDF Suez, which engage in electricity generation and also deliver power to end users. Industry companies that run power stations mainly to cover their own power needs.

4.4 Power transmission and interconnectors

Unlike many other European countries, Germany has multiple transmission grids and more than one transmission system operator (TSO). The four transmission system operators are:

- 50Hertz Transmission GmbH. Owned by Elia (60%) and IFM (40%). Geographical area: Eastern Germany.
- Amprion GmbH. Owned by RWE AG. Geographical area: Western Germany.
- TransnetBW GmbH. Owned by EnBW AG (87%) and Neckarwerke Stuttgart GmbH (17%). Geographical area: Southwestern Germany.
- TenneT TSO GmbH. Part of the Dutch TSO TenneT B.V. Geographical area: North-Western to South-Eastern Germany.

In the aftermath of the German government's requirement for the four major energy companies to separate their power transmission activities, Vattenfall and E.ON have sold their assets (to Elia and TenneT), while RWE and EnBW have outsourced their TSO activities to newly established companies.

Existing interconnectors are owned and operated by the four system operators depending on who is responsible for the area they are connected to in the German grid. The interconnector from Norway will be connected to the grid in the TenneT grid area.

Figure 16: Map of the German main grid showing the geographical area which the four transmission system operators, amprion, TenneT TSO, Transnet BW and 50 Hertz, are responsible for. The owners of the TSOs are shown above the name of the TSO.

4.5 Wholesale power market

Due to its geographical location in the middle of the European continent, Germany is connected to several other power markets. Germany is most closely connected with the Austrian market. The two countries constitute a joint price area in the day-ahead market that is operated by EPEX Spot SE. In November 2010, the trilateral market connection between France, Belgium and the Netherlands was expanded to include Germany and Luxembourg. The pentalateral connection is also called "the Central West Europe (CWE) electricity market». Even though Germany is part of a large joint day-ahead market established to maximise the benefit of the interconnectors between the five countries, there is still no common price in all the markets for all hours.

5 ORGANISATION OF THE UK POWER SECTOR AND POWER MARKET

5.1 Power system and balance

Thermal power stations that burn fossil fuels represent nearly 70% of power production. Nuclear power contributes just below 20 %. The remaining 10 per cent comes from various sources, of these wind power is the largest contributor. In 2011, the UK had an installed capacity of 90 000 MW. In the last 20 years, most of the about 30 000 MW of new production capacity has come from construction of gas fired power plants, based on first generation CCGT technology. These power plants have an efficiency of between 40 and 45%. The growth was particularly strong during the period 1990 to 2000. In the UK this development is often referred to as "the dash for gas.»

Consumption in 2011 was 345 TWh. The consumption record is 62 000 MW. Industry and the service industry represent about 60% of consumption and households less than 30%. In 2011, power production totalled 338 TWh, which means that Norway imported about 6 TWh net in 2011. The reason for this is that the trend where gas power took market shares from coal and nuclear power, which started in 2006, was reversed in 2011. Growth in renewable power production and a very negative profitability development for gas fired power stations have resulted in permanent and temporary shutdowns of many stations, particularly those with lowest efficiency.

5.2 The Electricity Market Reform («EMR»)

The main objective of EMR is to reduce the cost of meeting climate and renewable targets. In the UK these are legally binding. Investment in all current low-emission and renewable technologies is highly capital intensive. At the same time, analyses have shown that the established power companies did not have the financial strength to stimulate the necessary investments. The adopted policy instruments were consequently formed with a view to reducing capital costs associated with this type of investments. The policy also comprises investments in nuclear power production.

The two key reform measures are:

- Introduction of a Carbon Price Floor»). The purpose of the Carbon Price Floor is to provide the UK power sector with a quota price which is high enough to ensure that the policy instrument helps bring about the intended results, which has not been possible under the EU ETS scheme. In practice this means that a tax will be introduced on fossil fuels used for power generation. The tax is variable and will be set during the national budget negotiations.
- Introduction of Contracts for Difference. This is a subsidy regime which aims to reduce the price risk for producers of emission-free and renewable power by providing them with a guaranteed income from sale of the power they generate. The scheme entitles producers to a state payment which offsets the difference between the market price of power and the guaranteed price level.

The reform also comprises two other policy instruments:

- Introduction of a capacity mechanism to mitigate the fear of inadequate security of supply.
- Introduction of an Emission Performance Standard of 450 grams carbon/kWh. The purpose of the standard is to ensure that no coal-fired power stations are built without carbon capture, whilst not preventing construction of gas-fired power plants that are necessary to balance the variable power production from renewable sources.

5.3 Market structure and ownership

Over the last ten years, there has been a trend towards more vertically integrated power companies in the UK.

The main reason for this wave of acquisitions and mergers was the deregulation of the retail electricity market in 1998, which was implemented to achieve economies of scale, which one thought would be achieved with a customer base of several million customers. Further consolidation took place after the new market regulation scheme NETA was introduced in 2001. The consequence of this is that the Big Six[9], with their market share of 92%, are totally dominant in the retail electricity market.

5.4 Power transmission and interconnectors

National Grid owns the main grid and is responsible for system operations in England and Wales. The company is also responsible for system operation in Scotland, where the main grid is owned by the companies Scottish Power and Scottish & Southern Energy. National Grid's system operation costs are covered through a so-called TNUoS charge (Transmission Network Use of System charge»). Balance costs are covered through a so-called BSUoS charge (Balancing Services Use of System charge»).

The UK currently has three interconnectors to surrounding systems: Ireland, France and the Netherlands. In recent years, the UK has mainly exported to Ireland. The flow in the cables to the Continent varies more, but the UK has had net import.

5.5 Wholesale power market

In the UK there are several alternatives for day-ahead power trading:

- Power exchanges: There are two power exchanges: N2EX and APX-UK.
- Bilateral trading (OTC): Direct trading between market players or via a broker

The oldest power exchange is APX-UK, previously UPX before it was taken over by APX in 2003. The most liquid products are half-hour contracts that can be traded from two days until 15 minutes before gate closure (gate closure is one hour before physical delivery). Day-ahead auctions are also held here. However, the volumes traded here are low (10.4 TWh in 2011).

N2EX was established in January 2010. In 2011, 18.7 TWh was traded in the day-ahead market, twice as much as in the previous year.

The day-ahead products (base load and peak) are also traded over-the-counter (OTC), i.e. outside power exchanges. This type of trading makes up a significant part of power trading in the UK. There are several large brokerage firms covering the British market, including GFI, ICAP, TFS, Spectron and Tullet-Prebon. The company Heren functions as a price reporter. It obtains information about transactions in the OTC market on a daily basis (volume and price per product type). Based on this information, they prepare an index which provides the market players with a general daily overview of market developments.

Ofgem has long been concerned with the liquidity in the wholesale power market and has considered directly intervening to improve the situation. The market players have reacted to this, and beat Ofgem to the punch by launching their own solution to the problem. So far, their focus has been to increase the liquidity in the day-ahead market by contributing to the establishment of the power exchange N2EX and by committing to using the exchange as their preferred marketplace for day-ahead trading. Towards the end of 2011, each of the "Big Six" entered into a voluntary commitment to auction off at least 30% of their production volumes through the day-ahead auction at N2EX. Due to this measure, about 25-30% of the total consumption is currently traded in the day-ahead auction at N2EX. Ofgem is satisfied with this development and has thus refrained from taking direct action. Provided that the positive development continues, there is reason to believe that the UK will have an efficient day-ahead market in the future.

The EU aims to establish joint day-ahead and intraday power markets in Europe by 2014. A key aspect of the planned market model is so-called market coupling, a form of implicit auction. The British market coupling solution is called "the GB Virtual Hub». This solution will establish a single price for the two power exchanges

[9] EDF, Centrica, E.ON, RWE, Scottish Power, SSE

thus providing a common interface towards the other participating countries in the market coupling area which is called "North West Europe». Nord Pool Spot has been chosen to supply this service, and will be responsible for information exchange between the players.

Statnett

6 THE GERMANY PROJECT

6.1 Technical facility, route and connection to the main grid

The interconnector has a nominal capacity of 1400 MW. The cable will have a voltage level of 525kV and will be connected to the 380 kV grid in Germany and to the 420 kV grid in Norway.

The main components for the interconnector will be the following:

- Two converter/transformer substations, one in Norway (Ertsmyra) and one in Germany (Wilster). Each converter station requires an area of approx. 60 000 m2. VSC converter technology was chosen.
- Two parallel HVDC cables for the subsea section from Vollesfjord to Büsum.
  The subsea cable is 514 km long. Maximum water depth is approx. 450 metres and there will be 36 crossings. The cable type that will be used is called mass impregnated paper-insulated cable (MI). The same type of cable was used in the Skagerrak cables, NorNed and in most other HVDC cables in the world.
- Two parallel HVDC overland cables in Germany from Büsum to the connection point at Wilster.
  The underground cable is 55 kilometres long.
- Two parallel HVDC overhead power lines in Norway.
  The overhead line is 54 kilometres long. The first approx. 5 km will be built in parallel north of the 300 kV power line Feda-Åna Sirdal, the next approx.. 9 km in a separate route and the final approx. 39 km parallel west of existing Feda-Tonstad 2 (which will be upgraded to 420 kV).

Figure 17: General map showing the cable route between Vollesfjord in Norway and Büsum and Wilster in Germany. The section between Vollesfjord and Tonstand will have an overhead line. This part of the route is not indicated on the map.

6.2 Construction-related licences and agreements

6.2.1 Norway

Statnett submitted an application for a licence to construct the NORD.LINK cable in March 2010. As the plans for the NorGer project were virtually identical in terms of route and connection at Tonstad, a joint application for a construction licence was submitted in October 2010, upon request from the Norwegian Water Resources and Energy Directorate (NVE. The NVE is currently considering the application.

6.2.2 Denmark

The cable will cross Danish waters for a section of approx. 250 km before entering the German area. The establishment of new grid lines or significant modifications of the existing electrical supply grid on the Danish continental shelf is subject to the EU's habitat directive, even though the cable will not be connected to the Danish main grid. For this reason an assessment has been prepared of the project's impact on internationally protected natural areas such as "Natura 2000", as well as on relevant species listed in the habitat directive.

Statnett's application to Energistyrelsen (the Danish Energy Agency) includes a description of the expected impact from the cable on internationally protected natural areas, marine archaeological conditions, raw material resources, etc. The application also describes how the crossing of existing cables and pipelines will take place and how this will be regulated. A licence application was submitted to Energistyrelsen in November 2012.

6.2.3 Germany

In Germany the licensing process consists of two parts:

1. Land and sea within the 12-mile zone.
   This process consists of two sub-steps:
   a. Step 1 ("Raumordnungsverfahren") comprises application for a general permit to establish whether the project is feasible. A preliminary route corridor is prepared and this is described and planned.
   b. For Step 2 ("Planfeststellungsverfahren") a more detailed approach is required including detailed planning and adaptations of the approved corridor in Step 1.
2. Offshore (outside the 12-mile zone).

The German grid operator TenneT has for a long time been planning and developing solutions forlandfall and grid connection for the four offshore wind farms HelWin 1 and 2 and SylWin 1 and 2. The plan is to install the cables from these wind farms in parallel in the entire 12-mile zone and on land all the way to the connection point at the converter station. Grid connection for these wind farms (Büttel) is approx. 3 km from the connection point in Wilster which the project has been awarded.

As the project also has been granted an approval to install the cables in parallel with the cables from the wind farms, an exemption from 1ahas been made and permission granted to proceed directly to 1b and 2. The supporting technical material and all required studies have been prepared in accordance with German regulatory requirements and specifications. A preliminary application for Step 1b was submitted in August 2012. A preliminary application is submitted to receive feedback from the authorities on whether the application is considered to contain all relevant points that must be highlighted, a so-called completeness check». After more detailed work has been conducted on the basis of this feedback, the supporting documentation for the 1b application is scheduled for submission in mid-May 2013. Supporting licence documentation for Step 2 is scheduled for submission at the end of May 2013.

The normal processing time for applications is assumed to be a minimum of one year. However, the authorities envisage a speedy processing time in order to grant a licence for the project ahead of an investment decision in the summer of 2014. The German licensing process is assumed to be a critical part of the project.

6.3 Organisation of ownership

6.3.1 Partners

The Germany project is a cooperation between Statnett and DC Nordseekabel GmbH & Co KG ("DCNG"). DCNG is a German company, indirectly fully-owned by TenneT and KfW, each with an ownership interest of 50%.

TenneT is one of four TSOs in Germany. In the same manner as Statnett, TenneT administers the main grid and the interconnectors, monitors the reliability and reliability of supply and ensures balance between production and consumption of power. TenneT has about 900 employees, and is a subsidiary of TenneT B.V. The company is currently fully-owned by the Dutch state. TenneT in the Netherlands is Statnett's partner for the NorNed cable, of which each of the parties own 50%.

KfW is a German, state-owned finance institution. KfW was founded in 1948 as part of the Marshall Plan, and the name is originally from Kreditanstalt für Wiederaufbau.

The company DCNG was established specially for the Germany project. As owners, TenneT and KfW have a pro rata liability vis-á-vis Statnett to furnish DCNG with sufficient capital to ensure that DCNG can meet their project obligations in the development and construction phases.

The Germany project was originally initiated as a cooperative project between Statnett and TenneT (then Transpower Stromübertragungs GmbH). Statnett then continued with the project alone, before entering into an agreement with TenneT and KfW to continue developing the project together as equity partners.

6.3.2 Agreements

The relationship between Statnett and the owners of DCNG is regulated in the Principal Cooperation Agreement. The agreement focuses on ownership, including the German holding companies' financing obligations, and only covers operational matters such as market solutions, operation and maintenance to a small extent. The Principal Cooperation Agreement will be terminated when the cable enters operation, with the exception of certain matters that will be upheld until they are laid down in subsequent agreements if necessary.

The cooperation between Statnett and DCNG is further regulated through a Cooperation Agreement and an additional agreement. These agreements regulate e.g. the main principles for further development, construction and operation of the cable.

The Cooperation Agreement will be replaced by an Ownership Agreement, supplemented by special agreements relating to operation, maintenance, trading, etc. Entry into a satisfactory Ownership Agreement will be one of the preconditions for an investment decision in the project.

6.3.3 Ownership of the interconnector, revenue and cost distribution

Statnett will own the northern half of the interconnector and the onshore facilities in Norway. DCNG will own the southern half of the interconnector and the onshore facilities in Germany. By and large, the owner structure will be organised in the same way as TenneT and Statnett's ownership of the NorNed cable.

It has not yet been decided how operative matters will be structured on the German end of the cable in terms of compliance with TSO-related and other regulatory requirements pertaining to ownership and operation of the cable. Until this has been clarified, TenneT has committed to complying with DCNG's TSO-related obligations through the Principal Cooperation Agreement, to the extent that this is not possible for DCNG. This will ensure close cooperation at TSO level, comparable to that of Statnett's other existing interconnectors. Statnett will provide more information and documentation on regulatory clarifications on the German side as soon as possible, and assumes that a satisfactory structure will be in place before an investment decision is made.

From when the Cooperation Agreement is signed, investment and operating costs will generally be shared 50/50 between each party. The model is generally based on the same principles as the cost sharing model for the NorNed project, and the experiences Statnett and TenneT have from this.

Statnett has incurred separate costs relating to their own development of the Germany project in the period before entering into the Cooperation Agreement. The historical costs are subject to a special cost-splitting mechanism between the parties.

As a main rule, the parties will split the revenues generated from the cable equally. However, there is still a possibility, upon agreed terms, for a party to determine how its share of the transmission capacity can be made available in the market (less capacity allocated to trade in reserves). In such a case, the parties' revenues will be split accordingly.

6.4 The project development phase

6.4.1 Project organisation

Decisions in the joint project are made by a steering committee comprising representatives from KfW, TenneT and Statnett. In the project development phase, each country has its own project organisation and they cooperate through work groups. The parties cooperate on all support functions. The project is managed through a joint Project Management Plan (PMP).

6.4.2 Scope of work

The most important work in the phase leading up to the investment decision will be:

- Documenting sufficient socioeconomic profitability to make an investment decision
- Establishing a sufficient technical, financial and legal foundation for issuing tender documents (ITT)
- Negotiating construction contracts
- Establishing remaining agreements
- Entering into the necessary agreements and obtaining licences and permits relating to cable landing in Norway and Germany
- Further developing the partnership and establishing a joint, integrated construction organisation

6.4.3 Financing

Statnett assumes that the Norwegian share of the project development costs will be included in the Main Grid Commercial Agreement.

6.5 Project implementation phase

6.5.1 Project organisation

The parties agree to change the organisational structure during the implementation phase. The project's joint steering committee will remain with the same representation as in the development phase, but the implementation phase will be organised as one project under one joint project management. The actual organisation of the project following the investment decision will be decided by the steering committee prior to the investment decision

6.5.2 Schedule

If an investment decision is made in the summer of 2014 we assume that engineering and test activities will take place in the period leading up to 2015, when production of the cables will start. Production and installation will then take place in the period up until operations are scheduled to start in 2018. It will be determined how the progress plan can be optimised in order to meet scheduled commissioning of the facility in late autumn 2018.

6.5.3 Financing

Statnett assumes that the Norwegian share of the costs of establishing the interconnector will be included in the Main Grid Commercial Agreement. It is assumed that the investment is included in Statnett's revenue framework basis and that it is financed through raising new loans.

As for our German TSO partner, we expect that the German share will be included in the German main grid.

7 THE UK PROJECT

7.1 Technical facility, route and connection to the main grid

7.1.1 The technical facility

The interconnector has a nominal capacity of 1400 MW. The cable will have a voltage of 525 kV.

The main components for the interconnector will be the following:

- Two converter/transformer substations, one in Norway (Kvilldal) and one in the UK (Blyth). Each converter station requires an area of approx. 60 000 m2. VSC converter technology was chosen.
- Two parallel HVDC cables for the subsea part from Kvilldal to Blyth. The subsea cable is 720 km long. Maximum water depth is approx. 600 metres and there will be 65 crossings. The cable type that will be used is called mass impregnated paper-insulated cable (MI). The same type of cable was used in the Skagerrak cables, NorNed and in most other HVDC cables in the world.
- Two parallel HVDC overland cables in Norway. From the beach landing in Hylsfjorden, the cable continues by tunnel before it crosses Suldalsvatnet Lake and is routed in trenches for the final stretch up to the converter substation (see Figure 19). The route length is 6 km.
- Two short parallel HVDC overland cables in the UK

Figure 18: General map showing the cable route between Kvilldal in Norway and Blyth in the UK

7.2 Construction-related licences and agreements

7.2.1 Norway

Statnett will apply to have its current construction permit extended (from July 2018) and adjusted due to changed plans for the converter and new cable route that include a tunnel for running the cable from Hylsfjorden to Suldalsvatnet (see 44 Figure 19). An application will be submitted in 2013.

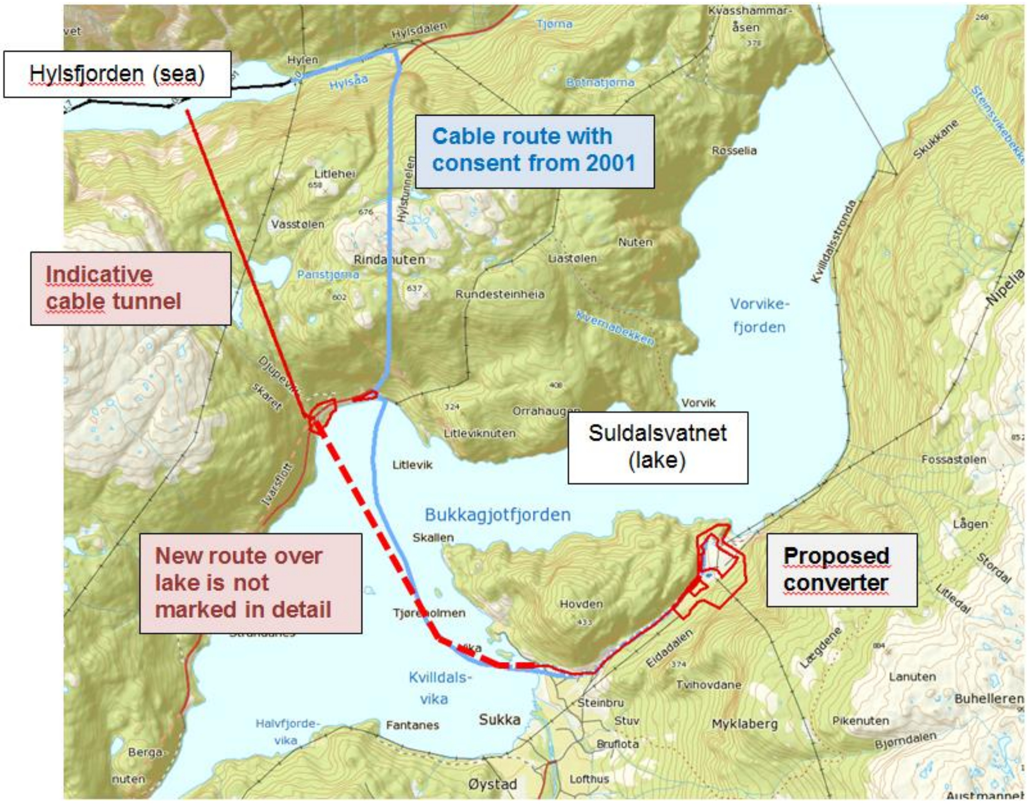


Figure 19: General map showing the land section of the planned cable route on the Norwegian end of the cable from the beach landing in inner Hylsfjorden. The cable route marked in blue shows the route that was applied for in 2001. The cable route marked in red shows the new route for which Statnett is planning to apply for a licence.

7.2.2 The UK

On the UK side, ground rights for the converter must be acquired, as well as permits for construction of the converter and a permit for installation of the underground cable from the sea to the substation.

Connection rights to the UK grid of 1400 mW capacity at the substation in Blyth have already been secured as of 1 October 2019.

7.3 Organisation of ownership

7.3.1 Partners

The UK project is a cooperation between Statnett and National Grid NSN Link Limited ("NSN Link").

NSN Link is a UK company indirectly fully-owned by National Grid Holding 1 Limited ("NGH1"), which is in turn directly and indirectly fully-owned by National Grid Plc. The activity in NSN Link is limited to this project. It is a precondition for an investment decision in the project that NGH1 furnishes a guarantee on behalf of Statnett for NSN Link's financial obligations related to the NSN project during the construction phase and a limited period of the operations phase.

NGH1 is the holding company for the National Grid Group's activity in the UK.

The ultimate parent company National Grid Plc. is listed on the London Stock Exchange, as well as the New York Stock Exchange. The National Grid Group owns and operates the transmission grid in the UK, Wales and the US. In the UK and Wales, the transmission grid is owned through the subsidiary National Grid Electricity

Transmission Ltd. ("NGET"), which is also the TSO for England and Wales and system operator for the UK. The National Grid Group is the partner on the UK side in existing and planned interconnectors to the UK.

7.3.2 Agreements

The cooperation between Statnett and NSN Link is regulated through a Cooperation Agreement. The Cooperation Agreement regulates main principles related to further development, construction, operations, etc.

The Cooperation Agreement will initially apply for the lifespan of the project. Furthermore, the parties must enter into an Ownership Agreement, as well as special agreements related to operation, maintenance, trade solutions, etc. In addition, a separate agreement will be entered into with NGET as TSO. Entering into a satisfactory Ownership Agreement and TSO agreement will be two of the preconditions for an investment decision in the project.

7.3.3 Ownership of the interconnector, revenue and cost distribution

As regards NSN Link's ownership and operation of the interconnector national regulations in the UK assume that interconnectors are developed on a commercial basis. The British TSO (NGET) does not have access to ownership and operation of interconnectors. It has been assumed that the British regulator, Ofgem, will offer NSN Link “regulated terms” that fulfil requirements under EU law, through a so-called Cap & Collar regime. Statnett will provide further information and documentation on regulatory clarifications on the UK side as soon as possible, and assumes that a satisfactory model has been clarified before an investment decision is made.

Until an investment decision has been made in the project, each of the parties will cover their own costs. From when the investment decision is made, investment and operating costs will generally be shared 50/50 between each party. The model is generally the same as the model for the Germany project and was built on the same principles as the cost sharing model for the NorNed project, and the experiences Statnett and TenneT have from this.

As a main rule, the parties will split the revenues generated from the cable equally. However, there is still a possibility, upon agreed terms, for a party to determine how its share of the transmission capacity can be made available in the market (less capacity allocated to trade in reserves). In such a case, the parties’ revenues will be split accordingly.

7.4 The project development phase

7.4.1 Project organisation

Decisions in the joint project are made by a steering committee comprising representatives from Statnett and National Grid. In the project development phase, each country has its own project organisation and they cooperate on various levels. The project is managed through a joint Project Management Plan (PMP).

7.4.2 Scope of work

The most important work in the phase leading up to the investment decision will be:

- Documenting sufficient socioeconomic profitability to make an investment decision
- Establishing a sufficient technical, financial and legal foundation for issuing tender documents (ITT)
- Negotiating construction contracts
- Establishing remaining agreements
- Entering into the necessary agreements and obtaining licences and permits for landing of the cable in Norway (Kvilldal) and the UK (Blyth)
- Further developing the partnership and establishing a joint, integrated construction organisation.

7.4.3 Financing

Statnett assumes that the Norwegian share of the project development will be included in the Main Grid Commercial Agreement.

7.5 The project execution phase

7.5.1 Project organisation

The parties agree to change the organisational structure during the implementation phase. The project's joint steering committee will remain with the same representation as in the development phase, but the implementation phase will be organised as one project under one joint project management. The actual organisation of the project following the investment decision will be decided by the steering committee prior to the investment decision

7.5.2 Schedule

If an investment decision is made in the summer of 2014 we assume that engineering and test activities will take place in the period leading up to 2015, when production of the cables will start. Production and installation will then take place in the period up until operations are scheduled to start in 2020. Converter stations are not a critical line in the project. During the contracting process, it will be determined how the progress plan can be optimised in order to meet scheduled start-up dates for the facility in late autumn 2020.

7.5.3 Financing

Statnett assumes that the Norwegian share of the costs of establishing the interconnector will be included in the Main Grid Commercial Agreement. It is assumed that the investment is included in Statnett's revenue framework basis and that it is financed through raising new loans.