# Increased Integration of the Nordic and German Electricity Systems

Modelling and Assessment of Economic and Climate Effects of Enhanced Electrical Interconnection and the Additional Deployment of Renewable Energies (Full Version)

**STUDY**

Agora Energiewende

GLOBAL UTMANING

Ea Energy Analyses

DTU

DIW BERLIN

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## IMPRINT


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Modelling and Assessment of Economic and Climate Effects of Enhanced Electrical Interconnection and the Additional Deployment of Renewable Energies (Full Version)

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# Preface

Dear Reader,

Increased integration of power systems is one of the prerequisites for the completion of the EU internal energy market – and with it the achievement of higher cross-border transmission capacities between European countries. The Nordic countries have vast potentials in renewable energy, such as wind energy, together with already existing hydropower reservoirs.

As part of the *Energiewende*, the German electricity system is undergoing the transition toward a high share of renewable energy – wind and solar photovoltaics in particular. Increased integration of the Nordic and German electricity markets will bring mutual benefits for power systems, greenhouse gas emissions mitigation and the wider economy. At the same time, increased integration affects stakeholders such as power producers and consumers in different ways in different countries. These effects are important to consider when increasing public acceptance for new (cross-border) transmission lines.

Agora Energiewende and the Swedish think tank Global Utmaning have put these issues to a consortium of three leading European research institutes. The aim of the resulting study was to examine the impact of increased integration between Nordic countries and Germany with a variety of renewable electricity shares. The study is meant to foster dialogue and discussions across countries and stakeholders, and encourage further research. The findings, as well as the accompanying technical reports, have been published on Agora Energiewende's website.

I hope you enjoy the read.

Kind regards,
Patrick Graichen
Director Agora Energiewende

## The Results at a Glance

1. **Increased integration between the Nordic countries and Germany will become ever more important as the share of renewables increases. The more renewables enter the system, the higher the value of additional transmission capacity between Nordic countries and Germany will become.** In particular, additional generation from renewables in the Nordics – reflected in the Nordic electricity balance - will increase the value of transmission capacity. There is a lot of potential for trade, due to hourly differences in wholesale electricity prices throughout the year.

2. **A closer integration of the Nordic and the German power systems will reduce $CO_2$ emissions due to better utilisation of renewable electricity.** This is caused by reduced curtailment of renewables, improved integration of additional renewable production sites and increased competitiveness of biomass-fuelled power plants.

3. **Higher integration will lead to the convergence of wholesale electricity prices between the Nordic countries and Germany. But even with more integration, the Nordic countries will see lower wholesale electricity prices if they deploy large shares of renewables themselves.** In general, additional integration will lead to slightly higher wholesale electricity prices in the Nordics and to slightly lower prices in Germany. But this will be counteracted by the decreasing price effect that higher wind shares in the Nordics have on the wholesale power market.

4. **Distributional effects from increased integration are significantly higher across stakeholder groups within countries than between countries.** This strongly impacts the incentives of market players such as electricity producers or consumers (e.g., energy-intensive industries) for or against increased integration. Distributional effects need to be taken into account for creating public acceptance for new lines and for the cross-border allocation of network investments.

# Content

# Content

WORK PACKAGE 2:
by DIW Berlin

# Content

# Key Findings and Conclusions

**1. Increased integration between Nordic countries and Germany will become ever more important as the share of renewables increases. The more renewables enter the system, the higher the value of additional transmission capacity between Nordic countries and Germany will become. In particular, additional generation from renewables in the Nordics – reflected in the Nordic electricity balance – will increase the value of transmission capacity. There is a lot of potential for trade, due to hourly differences in wholesale electricity prices throughout the year.**

The Nordic countries have large untapped potentials of wind energy and existing hydropower reservoirs. By 2035 Germany aims for a 55 to 60 percent share of renewables in final electricity consumption as part of its "Energiewende" (energy transition), while by the same year Denmark plans to have an entirely renewable electricity and heat sector. Increased interconnection facilitates renewable based electricity generation in the region and opens up greater cross-border balancing possibilities for integrating fluctuating levels of renewable energy. There is substantial potential for electricity trade from the differences in hourly wholesale electricity prices between the Nordic region and Germany. Trade potential between the two regions emerges if high and low wholesale electricity prices occur at different hours. If wind power production in Norway, Sweden and Germany quadruples in the next 15 years, then wholesale electricity prices will be lower in the two Nordic countries than in Germany for approximately 7,000 hours per year. This implies that the main direction flow is from Norway and Sweden (low price areas) to Germany (high price area), with Nordic countries exporting electricity to Germany annually. The interconnectors are used to a lesser extent for export from Germany to the Nordic countries. The possibility of exporting additional generation from renewables increases the value of additional transmission capacity. This underscores the viability of the projects of the Ten Year Network Development (TYNDP) 2014 for the year 2030. If renewable deployment is only moderate, however, there will be fewer hours with electricity surplus in either region. This reduces the price spread between the Nordic and German regions and lowers the value of additional transmission capacity considerably.

**2. A closer integration of the Nordic and the German power systems will reduce $CO_2$ emissions due to better utilisation of renewable based electricity. This is caused by reduced curtailment of renewables, improved integration of additional renewable production sites, and increased competitiveness of biomass-fuelled power plants.**

A high deployment of electricity from renewable energy sources in the Nordic countries and in Germany will lead to a significant reduction of $CO_2$ emissions by 2030. Based on our assumptions in the High Renewable scenario, the electricity sector and the heat sector (the latter in Scandinavia) can expect a reduction of 40 to 55 percent relative to 2013. Increased grid integration, between and within countries, will improve options for choosing sites with good (wind) resources. This may allow wind deployment further north in Norway and Sweden, where wind conditions are more favourable. Furthermore, increased grid integration will reduce curtailment of hydro and wind power, and hence raise the level of $CO_2$ free renewable feed-in. Finally, biomass-fuelled power plants (such as those in Denmark) may become more competitive due to better market integration. For creating investor confidence in renewable generation, sufficient grid capacity is necessary to accommodate the feed-in of new production sites connected to the grid.

**3. Higher integration will lead to the convergence of wholesale electricity prices between Nordic countries and Germany. But even with more integration, the Nordic countries will see lower wholesale electricity prices if they deploy large shares of renewables themselves. In general, additional integration will lead to slightly higher wholesale electricity prices in the Nordics and slightly lower prices in Germany. But this will be counteracted by**

**the decreasing price effect that higher wind shares in the Nordics have on the wholesale power market.**

Average wholesale electricity prices are lower in the Nordic region than in Germany. The level of wholesale electricity prices is affected both by the level of renewable energy deployment and by the level of transmission capacity. Grid integration triggers price convergence, translating into a relative increase of average wholesale electricity prices in the Nordic countries and into a slight decrease of average prices in Germany. If there is high renewable deployment (wind) in Scandinavia, a relative drop in wholesale electricity prices will be observable in the Nordic region, partially counteracting the price increase induced by more transmission capacity. In general, additional integration benefits power producers in countries with relative price rises and electricity consumers in countries with relative price drops. This implies that in the Nordic countries hydropower and wind generators will gain the most in stakeholder rent, while Nordic consumers will face higher wholesale electricity prices. By contrast, in Germany consumers will benefit from lower electricity prices, whereas power producers will mostly incur losses. Notably, the Nordic power market is smaller in size and less integrated with additional neighbouring systems. Hence, the effects of additional transmission capacity on prices and on the distribution of stakeholder rent will be more pronounced in the Nordic countries than in Germany.

**4. Distributional effects from increased integration are significantly higher across stakeholder groups within countries than between countries. This strongly impacts the incentives of market players such as electricity producers or consumers (e.g., energy-intensive industries) for or against increased integration. Distributional effects need to be taken into account for creating public acceptance for new lines and for the cross-border allocation of network investments.**

The costs and benefits of increased integration will be allocated asymmetrically across countries. This could hamper the regional development of the electricity system, especially if internal line upgrades are needed for higher cross-border integration. Denmark is likely to play a special role as a transit country, serving as a hub between Nordic countries and Germany. The distributional changes among stakeholders – different types of producers and consumers – will be substantially higher in one single country than the distributional changes from integration between countries. This will strongly impact the incentives of different market players such as electricity producers and consumers for or against increased integration. Competitiveness of energy-intensive industries is a sensitive issue of national industrial policy. For large and energy-intensive industrial power consumers, the cost of electricity supply is mostly driven by the electricity price at the wholesale market. Therefore, varying or increasing electricity prices will have a non-negligible impact on the cost structure of these branches in relative terms. Electricity producers and consumers will be affected asymmetrically across countries. The implied repercussions of stronger integration provide a base for understanding and shaping targeted policy measures at the European and national levels. European cross-border cost allocation schemes need to take this into account if they are to avoid opposition by countries or stakeholders, which could undermine interconnector projects. Increased system integration is a prerequisite for connecting high volumes of renewable energy in the long run.

# Executive Summary

The Nordic countries have vast potentials in renewable energy, such as wind energy, together with already existing hydropower reservoirs. At the same time, as part of the "Energiewende", the German power system is undergoing the transition toward a system with high shares of renewable energy – wind and solar photovoltaics, in particular.

The aim of this study is to assess and discuss the economic and climate effects of further integration of the Nordic and German power systems through 2030. The project's analysis is both quantitative and qualitative.

We identified **four core scenarios** for future development with two parameters of variation:

- → the level of renewable energy deployment in electricity (RES-E), and
- → the level of grid integration between Nordic countries and Germany.

A partial equilibrium model – Balmorel – was used to simulate hourly production patterns (least cost optimisation). The model runs generated results for infrastructure investments, prices, generation and system costs at national and system levels. From these results we analysed the distributional effects of integration among stakeholders.

The study finds that renewable deployment is the major influencing factor for the generation mix. When more renewables enter the system, they induce an increased value of transmission capacity between the Nordic countries and Germany. High deployment of renewables in the Nordic countries, which is reflected in the Nordic electricity balance, increases the value of transmission capacity in particular.

In the case of moderate renewable deployment (ModRE scenario), our modelling results yield that almost 70 percent of the total national electricity production in the core countries of the model will be based on renewable energy sources in 2030. In the High Renewable scenario, an additional 128 Terawatt hours (TWh) of solar and wind feed-in is part of the generation mix. Germany's conventional generation is then reduced by 47 TWh as compared to the moderate renewable case. In total, the High Renewable scenario sees a generation increase in the Nordic-German region by roughly 50 TWh. The generation mix is only slightly affected by adding transmission capacity. Hence, an increase in transmission capacity has only a limited effect on the generation mix as such.

There is great potential for increased electricity trade between the Nordic countries and Germany. More renewables augment the value of transmission capacity. Power

Scenario setup — Table 1

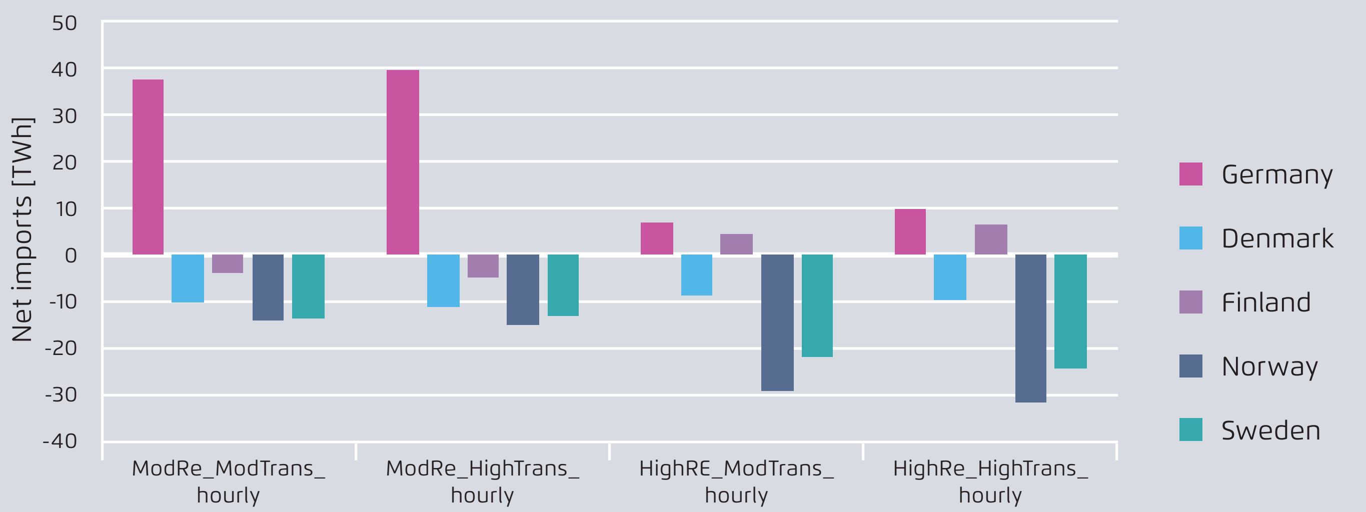
More RES-E →

More Transmission ↓

| | Moderate RES-E | High RES-E |
|---|---|---|
| Moderate integration of grids | ModRE_ModTrans | HighRE_ModTrans |
| High integration of grids | ModRE_HighTrans | HighRE_HighTrans |

Ea and DTU, 2015

Net annual imports to the Nordic countries and Germany in the four scenarios.
Imports include imports from surrounding countries. Negative net imports signify exports. Figure 1




Ea and DTU, 2015

will be exported yearly from the Nordics to Germany, but in reality trade patterns will be more complex, playing an important role in balancing variable (renewable) electricity production. The electricity balance, in particular the high renewable deployment levels in the Nordic countries in the High Renewable scenario, will be a crucial driver of increasing the value of transmission capacity.

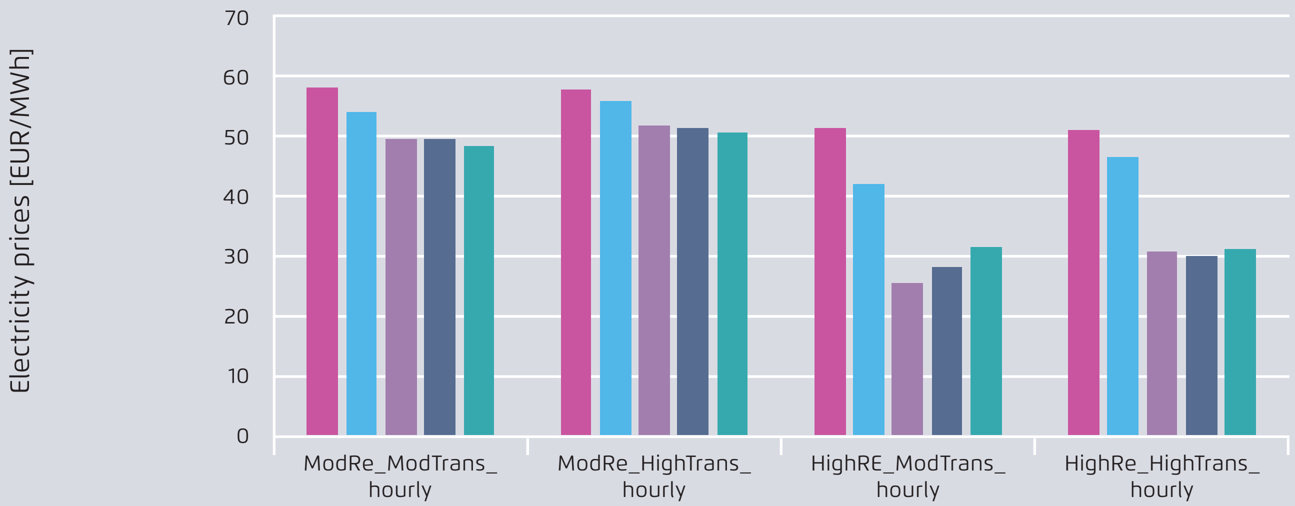
Generally, Scandinavia has relatively low wholesale electricity prices. Higher transmission capacity leads to increased market integration, and, hence, to higher average wholesale electricity prices in the Nordic countries and lower prices in Germany. Notably, in the High Renewable scenarios, the wholesale electricity prices drop sharply in the Nordic region relative to the moderate renewable deployment case. This price drop counteracts the price increase induced by more transmission capacity. In other words, even with more integration, the Nordic countries will face no significant wholesale electricity price increase as long as they deploy large shares of renewables themselves.

The wholesale price is affected both by the level of renewable energy deployment and by the level of transmission capacity. As shown in Figure 2, the major influencing factor for wholesale electricity prices is the level of renewable energy deployment.

According to the study's findings, the deployment of additional renewables in the Nordic countries and in Germany leads to a significant reduction in $CO_2$ emissions. While the emissions effect of additional transmission capacity itself is limited, an increase in transmission capacity constitutes a prerequisite for higher renewable integration. This shows again that increased renewable deployment is the main factor for achieving high emissions reductions. Increased interconnectivity of the grids can be regarded as a requirement for higher investment volumes in renewables.

From the power market and systems standpoint, increased grid integration has a positive welfare effect overall. Compared with welfare effects between countries, levels of redistribution are significantly higher across stakeholder groups within a single country. In general, increased integration benefits producers in countries with increasing wholesale electricity prices and consumers in countries with decreasing prices. In the Nordic countries, hydropower and wind generators stand to gain the most, while

Average annual wholesale electricity prices in 2030. Wholesale price level for the countries is expressed as a simple average across regions. In reality the wholesale electricity price will vary considerably in each country over the year. (Note that the wholesale price is not the consumer price, which includes additional costs such as taxes, levies and distribution fees.) Figure 2




| | ModRe_ModTrans_ hourly | ModRe_HighTrans_ hourly | HighRE_ModTrans_ hourly | HighRe_HighTrans_ hourly |
|---|---|---|---|---|
| Germany | 58 | 57 | 51 | 51 |
| Denmark | 54 | 56 | 42 | 46 |
| Norway | 49 | 51 | 25 | 30 |
| Sweden | 49 | 51 | 28 | 30 |
| Finland | 48 | 50 | 31 | 31 |

Ea and DTU, 2015

consumers face higher electricity prices. In Germany, electricity consumers benefit from lower prices, whereas power producers mostly incur losses. At the country level, the biggest beneficiaries are Norway and Germany in the case of moderate renewable deployment, and Sweden and Norway in the case of high renewable deployment. Notably, because the Nordic power market is smaller in size and is less integrated in other neighbouring systems, added transmission capacity has stronger effects on Nordic wholesale electricity prices.

Seasonal hydro storage in Norway and Sweden is often considered one of the main drivers for integration due to its flexibility, allowing it to compensate for wind generation fluctuations in the North Sea and Baltic Sea regions. Stronger integration provides opportunities for trade in both directions. Wholesale electricity market prices do not indicate clear additional benefits from integration for hydro storage. But other benefits may arise, such as improved integration of variable wind energy production or improved regional supply security through balancing annual inflow variations in Nordic hydropower during dry and wet years.

The distribution of benefits from increased integration strongly affects the incentives of different market players such as electricity producers or consumers for or against new (cross-border) transmission lines. These distributional effects need to be taken into account for creating public acceptance for new lines and for the cross-border allocation of network investments. A lack of incentives due to asymmetrical distribution effects could be levelled out by cross-border cost allocation schemes between countries. The price impact on individual stakeholders, such as specific consumer groups, depends on final electricity prices. In addition to energy and supply costs, these may include network costs, taxes and other levies. Energy-intensive industries in the Nordic countries are most directly exposed to an increase in wholesale electricity prices.

The aging electricity systems in the Nordics and in Germany are up for renewal. To increase their flexibility, new, forward-looking system designs are needed. Grid expansion and cross-border interconnectors constitute an important flexibility option for balancing variable generation across larger regions. Distributional effects introduce a political dimension in addition to economic considerations. The political dimension has a "good neighbours" element: prudent cost allocation schemes can facilitate the overall benefits of integration. Overarching goals, such as the completion of the European energy market and the *common* provision of security of supply, need to be taken into account when discussing the total value of increased integration. In the long run, costs are not the only thing that is important; total value creation is as well. We need continued regional dialogue across stakeholders and countries about cost sharing, incentives and future goals.

# Economic and Climate Effects of Increased Integration of the Nordic and German Electricity Systems

Outlook for Generation and Trade in the Nordic and German Power System – Work Package 1


**WRITTEN BY**

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# 1 Executive Summary

The current study analyses the effects of closer integration of the Nordic and German electricity systems through increased investment in transmission lines. The study is based on both an analysis of the value of increasing capacity on specific lines and on forecast scenarios. Four different scenarios are calculated. They differ in the variation of two parameters:

→ the amount of renewable energy deployment within the Nordic and German systems
→ the transmission capacity of selected transmission connections (Table 1).

The calculations are performed for 2030 using the Balmorel electricity and heat system model.

The results as a whole show substantial potential for increased electricity trade between the Nordic countries and Germany. On an annual basis, the Nordic countries export significant amounts electricity to Germany, indicating that surplus generation from electricity based on renewable energy sources (RES-E) is an important driver of transmission capacity. However, transmission lines are also used for balancing out fluctuations in RES-E production in the region.

Closer integration of the Nordic and German electricity systems leads to a reduction in total $CO_2$ emissions due to the optimised utilisation of RES-E. This is caused by reduced curtailment, greater options for locating new renewable energy capacity at sites[1] with good resources, and the increased competitiveness of biomass power plants due to improved market integration. Improvements in market integration may also lead to increased investment in RES-E, thereby further reducing $CO_2$ emissions. This effect is not quantified in this study.

Wholesale electricity prices are affected by both the level of RES-E deployment and transmission capacity. In general, higher transmission capacity leads to increased market integration and therefore to higher average prices in the Nordic countries and to lower average prices in Germany. However, with increasing RES-E deployment comes a drop in wholesale electricity prices, which counteracts the price increase induced by higher transmission capacity. The greater price difference between the Nordic region and Germany in the HighRE scenarios shows – among other things – the increased potential for electricity trade when more RES-E has to be integrated into the system. The results for the ModRE scenarios show potential for increasing transmission capacity between the Nordic countries and Germany. However, a cost-benefit analysis shows that investing in the maximum possible number of additional transmission lines in the ModRE_HighTrans scenario is not necessarily beneficial. The ModRE_HighTrans scenario shows a total economic benefit of approxi-

Scenario setup — Table 1

More RE →

More Transmission ↓

| | Moderate RES-E | High RES-E |
|---|---|---|
| Moderate integration of grids | ModRE_ModTrans | HighRE_ModTrans |
| High integration of grids | ModRE_HighTrans | HighRE_HighTrans |

Own illustration

closer resource analysis as well as other planning factors.

mately €60 million/year, which is considerably lower than the estimated annual cost of investing in the new transmission capacity, ranging from €208 million/year to €348 million/year. The benefit of the total transmission package increases in the HighRE scenarios to around €250 million. Therefore, the additional transmission lines might prove to be socio-economically beneficial, depending on the actual costs of the project, applied lifetime, and interest rates.

In addition to conducting a cost-benefit analysis of investment in additional transmission lines overall, we estimate the marginal value of increasing capacity on specific lines within each scenario. Although the marginal value of additional transmission capacity is only valid for marginal changes of transmission capacity, it gives a good indication of where it would be beneficial to reinforce interconnections between regions. However, the values are not valid for large changes in transmission capacities and may be affected by other changes to the transmission system. This means it is not possible to benefit from all marginal values at the same time. Table 2 clearly shows that the marginal values increase with increased deployment of RES-E, and decrease in the HighTrans scenarios, where additional investments have been made. The table also shows that there are considerable differences between the analysed transmission lines.

Overall, the study identifies significant potential for closer integration of the Nordic and the German electricity systems. Careful analysis of the most important bottlenecks is necessary to ensure a net socio-economic benefit from increased investment in transmission. The amount of RES-E deployment and domestic annual power balances are important factors affecting the value of transmission. Further value can be generated from sharing system flexibility options and system stability services across the region. This effect would be a fitting topic for further research.

Marginal values of transmission capacity for transmission lines with higher capacity in the High Transmission scenarios (HighTrans). The cost estimates are based on data from the TYNDP 2014 with an interest rate of 4 percent and a 30 year lifetime. Operational and maintenance costs as well as costs of losses are not included.

Table 2

| Marginal value of transmission k€/MW | | | | | | | |
|---|---|---|---|---|---|---|---|
| **From** | **To** | **Capacity (Additional) MW** | **Cost k€/MW** | **ModRE ModTrans** | **ModRE HighTrans** | **HighRE ModTrans** | **HighRE HighTrans** |
| DK_W | DE_NW | 2,500 (500) | 20–24 | 32 | 17 | 74 | 42 |
| SE_S | DE_NE | 0 (700) | 17–33 | 90 | 74 | 206 | 185 |
| SE_N1 | FI_R | 1,300 (1,000) | 4–7 | 8 | 1 | 45 | 21 |
| NO_N | FI_R | 0 (500) | 35–81 | –* | 12 | –* | 53 |
| NO_N | SE_N2 | 275 (750) | 11–25 | 32 | 13 | 86 | 33 |
| DK_E | DE_NE | 600 (600) | 48–59 | 48 | 17 | 110 | 44 |
| SE_S | SE_M | 4,850 (700) | 14–22 | 3 | 3 | 5 | 8 |
| NO_M | NO_N | 600 (1,200) | 42–72 | 20 | 5 | 42 | 10 |
| DK_W | DK_E | 600 (600) | 38–46 | 18 | 1 | 39 | 4 |
| SE_M | SE_N2 | 8,000 (700) | 66–116 | 9 | 6 | 20 | 19 |

Own calculation; *Marginal value not shown if transmission line does not exist in the scenario.

The purpose of this study is to assess and discuss the economic and climate impacts of further integrating the German and Nordic electricity systems through increased investment in transmission lines.

A number of studies have pointed at significant benefits from closer integration of the electricity grids in the region.[2] The benefits are derived from four main factors:

- → The Nordic countries are endowed with great renewable energy potentials that could possibly lead to a **green generation surplus** in the coming years, which could then be exported to continental Europe.
- → Nordic hydropower may be operated in a very flexible way and can act as a **very efficient battery** for storing variable renewable energy, whether produced in the Nordic countries or imported from continental Europe (indirect storage).
- → Closer integration of grids will lead to more stable renewable energy generation because wind power (and to some extent solar power) demonstrate significant **geographic smoothing effects**.
- → Flexible resources in both generation and demand could be shared across regions to a greater extent. These include resources for back-up when wind and solar power plants are not actively generating as well as ancillary services to ensure that the system operates smoothly.

Based on the possible benefits, this study focuses on:

2 Thema Consulting Group (2013) (commissioned by Svensk Energi): *Cables – Strategic options for Sweden*; Svenska Kraftnät (2012): *Resultat från en marknadsmodellstudie - Appendix till Perspektivplan 2025*; Prognos (2012)(commissioned by Weltenergierat - Deutschland e.V.): *Bedeutung der internationalen Wasserkraft-Speicherung für die Energiewende*; Institute for Power Systems and Power Economics RWTH Aachen University (2014)(commissioned by TenneT TSO Gmbh and Energinet.dk): *Investigation of welfare effects of increasing cross-border capacities on the DK1-DE interconnector*; SINTEF Energy Research (2013): *Twenties. Transmitting Wind. Task 16.3 Possibilities of Nordic hydro power generation flexibility and transmission capacity expansion to support the integration of Northern European wind power production: 2020 and 2030 case studies*

# 2 Introduction

- Overall system costs and benefits, including capital costs, operation and maintenance costs, fuel and $CO_2$ costs and (avoided) curtailment of renewables and greenhouse gas emissions
- Electricity generation mix and electricity trade within and between Germany, the Nordic countries, and other affected countries, as well as electricity prices
- The implications for domestic grid infrastructure requirements

This document describes four different scenarios with different rates of renewable energy (RE) deployment and grid integration. A major source for input assumptions for all scenarios is the ENTSO-E Ten Year Network Development Plan for the Baltic Sea Region (ENTSO-E TYNDP 2014).

The Balmorel model (http://www.balmorel.com) is used for the purpose of quantitative analysis in this study. The model includes a representation of the electricity and district heating systems in Northern and Central Europe. A more detailed model description can be found in the appendix.

The appendix also gives an overview of the different countries' existing power systems and other key model inputs, including estimated fuel and $CO_2$ quota prices and projected electricity and heating demand.

A number of factors are likely to influence grid development in the region, including the development of smart grids, the uptake of new technologies and the role of nuclear power. However, the rate at which variable renewables are deployed towards 2030 is likely to be the single most important driving factor. Accordingly, this is the project's main focus.

Four core scenarios were established based on the variation of two parameters:

- → the level of renewable energy deployment; and
- → the level of grid integration between Germany and the Nordic countries.

These scenarios are presented in the table below. All other parameters are set equally in each of the four scenarios; in other words, they rely on the same projection of electricity demand, the same projection of fuel prices and the same $CO_2$ prices for the year 2030.

Both the electricity from renewable energy sources (RES-E) and the level of grid integration (NTC[3] values) are determined exogenously in the Balmorel model simulations.

Table 4 gives an overview of common assumptions across the scenarios and the differences between them. A detailed explanation follows below.

## 3.1 Main assumptions

**RES-E deployment**

RES-E deployment is fixed at the same level for 2020 in all scenarios, but differs for 2030. The scenarios with high RES-E have greater deployment of RES-E, while the scenarios with moderate RES-E have more moderate deployment.

RES-E deployments for the scenarios for 2030 are based on both national studies and assumptions from Vision 3 and Vision 4 of the ENTSO-E 10-year Network Development

3 Net Transfer Capacity

# 3 Scenario Setup

Plan (TYNDP 2014).[4] Vision 3 in the TYNDP 2014 is called "Green Transition" and is based on transmission system operators' (TSO's) plans, reflecting national energy policies and favourable economic conditions. Vision 4, called "Green Revolution", is the most ambitious scenario in the TYNDP, in which RES-E is the primary method of generation and fossil fuels play a secondary role.

Where possible, official national data (e.g. based on scenarios by regulatory agencies or objectives stipulated by governments) are used. The motivation for this approach is that the levels of RES-E deployment in the electricity sector may to a great extent be driven by national policies, RES targets and support schemes.

**Grid expansion**

The assumed development of net transmission capacities (NTC) is based on the TYNDP 2014 for all countries. The NTCs between and within Germany and the Nordic countries vary according to the actual scenario, while NTCs between and within neighbouring countries are based on existing grid expansion projects from TYNDP 2014 that are completed by 2025 and kept constant in the different scenarios.

Renewable energy deployment scenarios — Table 3

More RE →

More Transmission ↓

| | Moderate RES-E | High RES-E |
|---|---|---|
| Moderate integration of grids | ModRE_ModTrans | HighRE_ModTrans |
| High integration of grids | ModRE_HighTrans | HighRE_HighTrans |

Own illustration

Differences and common assumptions across scenarios — Table 4

| Variations | Common assumptions |
|---|---|
| → RES-E deployment within the Nordic countries and Germany<br>→ Grid expansion within and between the Nordic countries and Germany (TYNDP 2020 and 2030)<br>→ Investment in new generation capacity within the Nordic countries and Germany (model optimised investments)<br>→ Decommissioning of existing capacity (model optimised investments) | → RES-E deployment and other investments in neighbouring countries<br>→ Grid development within and between neighbouring countries (TYNDP until 2025)<br>→ Fuel and CO2 prices<br>→ Electricity and heat demand |

Own illustration

The assumptions for the moderate integration of grids between the Nordic countries and Germany (Scenario ModRE_ModTrans and HighRE_ModTrans) are based on grid projects from TYNDP 2014 finished by 2020, but no further grid expansions between 2020 and 2030 are included. The NTCs for the high integration of grids (Scenario ModRE_HighTrans and HighRE_HighTrans) are based on the TYNDP 2014, including projects planned for commissioning up to 2030.

**Other generation capacities**

Assumptions for other generation capacities are based on a bottom-up approach that takes into account government plans in each respective country, including the official decommissioning of thermal and nuclear power plants. For example, in Germany the *Bundesnetzagentur* (the utility system regulator) publishes and regularly updates a list of coal-fired power plants that will be disconnected from the grid.

With regard to nuclear power, Germany's existing phase-out plan, which specifies decommissioning dates for individual reactors, is taken into account in the scenario assumptions. For Finland, current plans to commission additional nuclear power stations are also included. For Sweden, assumptions on the development of nuclear power are based on the recent announcements by the current government and the anticipated reactions of power producers. This entails a slight increase in capacity until 2020 through the upgrading of existing capacity and a decrease between 2020 and 2030 due to phase out of old units as a result of new safety standards and higher taxes/levies.

**Electricity demand**

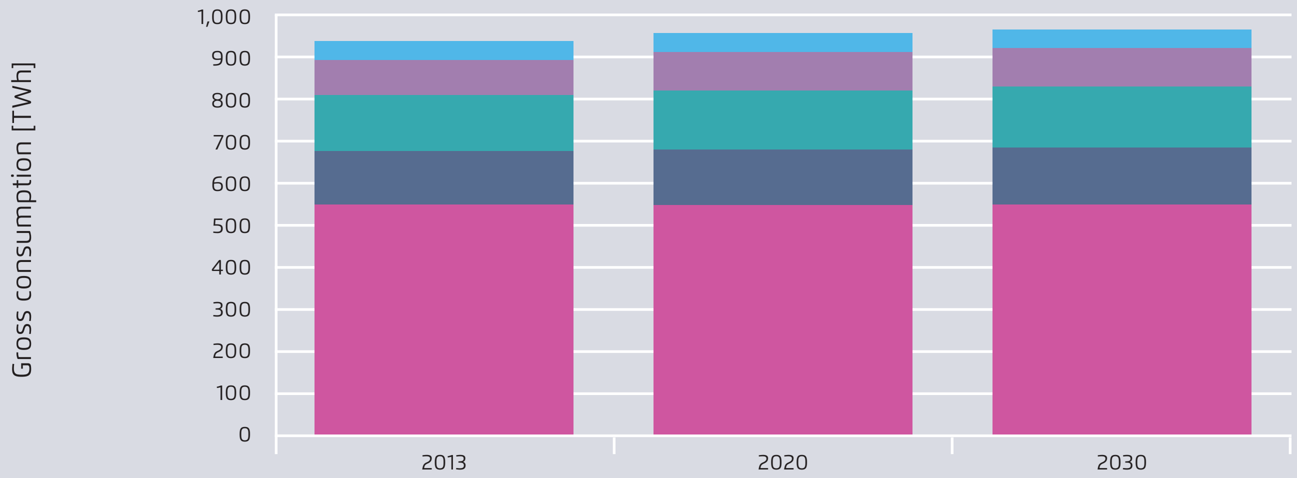
Gross electricity demand in the model is based on various national forecasts. The projection is to be understood as a net projection, including the effects of improvements in efficiency as well as some electrification of other sectors such as individual heating and transport. However, the explicit contribution of the different parameters was not analysed in detail in this project.

For Norway, a demand increase of approximately 10 TWh (net) from 2013 to 2030 has been estimated. The Norwegian transmission system operator Statnett forecasts an increase in electricity demand in the Grid Development Plan 2013[5] without stating the total amount in TWh. The net increase covers increased consumption from industry, including electrification of some oil and gas production both on- and offshore. Other sources agree with the forecast of increasing demand.[6] However, the demand projection should be considered in conjunction with expectations for the development of hydropower. Increasing generation from hydropower without increasing domestic demand will be a challenge for overall system balance (see also section 5).

5 Grid development plan 2013 – National plan for the next generation main grid, Statnett, October 2013.

6 CenSESenergiframskrivinger mot 2050, IFE/KR/E-2014/003, Institutt for energiteknikk, 2014. The report mentions a number of scenarios for the development of electricity demand, showing both higher (up 30 TWh by 2030) and lower (up to 10 TWh) estimates compared to 2010.

Projected electricity demand for individual countries (including grid losses, excluding power plant consumption, electricity consumption for district heat production – e.g. in large heat pumps – and telectricity consumption for pumped hydro storage) Figure 1




| | 2013 | 2020 | 2030 |
|---|---|---|---|
| Denmark | 35 | 37 | 40 |
| Finland | 84 | 94 | 94 |
| Sweden | 137 | 140 | 139 |
| Norway | 128 | 132 | 139 |
| Germany | 555 | 553 | 552 |

Own calculation

### Fuel and $CO_2$ prices

Assumptions regarding fuel and $CO_2$ prices are based on the IEA World Energy Outlook (2013).[7] The deployment of renewable energy can be driven by national policies or EU regulation such as the emissions trading scheme (ETS). The effect of the ETS is not assessed separately in the different scenarios, i.e. we assume that the ETS framework is the same across scenarios, expressed by the same $CO_2$ price. This implies that the impact of varying $CO_2$ prices as a driver for RES-E penetration is not a subject of the scenario analyses.

### Timeframe

The timeframe of this study is the year 2030. Model simulations were conducted for the years 2013 (reference case), 2020 and 2030. While the year 2050 is not part of the modelling exercise, the more ambitious RES-E scenarios reflect higher penetration levels of variable renewable energy sources in electricity generation, which may also correspond to future scenarios.

### Geographical scope

The core countries considered in this study are Germany and the Nordic countries (Norway, Denmark, Sweden and Finland). Scenario assumptions and variations focus on these countries. However, the model simulations also include the remaining countries in the Baltic Sea region (Estonia, Latvia, Lithuania and Poland) as well as Germany's neighbouring countries and the United Kingdom. Detailed results are shown for core countries, while only electricity flows and annual average electricity prices are shown for the neighbouring countries.

7 International Energy Agency (2013): World Energy Outlook 2013

## 3.2 RES-E deployment

**Main assumptions**

The assumptions regarding the deployment of renewable energy within the entire model area is the same for all scenarios until 2020. For neighbouring countries, which are not part of the core analysis, the National Renewable Energy Action Plans (NREAPs)[8] are used to define the development until 2020, which are then kept fixed in all scenarios. After 2020 a common level of subsidies for RES-E is used to estimate investments in renewable energy capacity in the main scenario (ModRE_ModTrans) and kept unchanged in the remaining scenarios.

For the core countries, RES-E deployment in 2030 depends on the scenario (Table 5). RES-E levels for the core countries are defined exogenously and not directly subject to model optimisation. The necessary subsidies to achieve the predefined levels for RES-E in reality are not analysed in this study.

**Modelling RES-E deployment**

For modelling purposes, only capacity or annual electricity production is defined exogenously, while the other, non-exogenously defined variables are model results and to some extent subject to optimisation. Biomass and biogas electricity production volumes are defined exogenously, while the capacities needed to generate given production levels are model results. An exception to this is biomass and biogas production in Denmark, where both capacity and production is derived from endogenous optimisation based on the current tax- and subsidy system. For wind power and solar power, the capacities are defined exogenously, while availability of wind and solar resources define their annual electricity production. The reason for the different approach is that defining the capacity of biomass power plants is not enough to ensure the desired annual production. The short run marginal power production cost might lead to low utilisation of the power plants. On the other hand, wind and solar power have low short run marginal power production costs, and so defining the capacity (which requires less computation time) is sufficient to ensure the annual production level.

8 National Renewable Energy Action Plans submitted to the European Commission: http://ec.europa.eu/energy/en/topics/renewable-energy/national-action-plans

Sources for the RES-E scenario setup Table — Table 5

| | 2020 | 2030 High RE | 2030 Moderate RE |
|---|---|---|---|
| **Germany** | Projection based on the Renewable Energy Act (EEG)* | Vision 4 of ENTSO-E TYNDP 2014 | Scenario B of 1st draft of NEP scenario framework 2015** |
| **Denmark** | National targets exceeding NREAP:<br>- 50 % wind target<br>- coal to biomass conversion | Hydrogen Scenario by Danish Energy Agency | Danish TSO Energinet.dk's plans***, Danish Energy Agency**** |
| **Sweden** | National Renewable Energy Action Plan | Swedish Energy Agency's Checkpoint 2015 Report and higher RE targets | Swedish Energy Agency's Checkpoint 2015 Report***** |
| **Norway** | National Renewable Energy Action Plan | Vision 4 of ENTSO-E TYNDP 2014 | Vision 3 of ENTSO-E TYNDP 2014 |
| **Finland** | National Renewable Energy Action Plan | Vision 4 of ENTSO-E TYNDP 2014 and VTT Low Carbon Finland 2050 | Vision 3 of ENTSO-E TYNDP 2014 and VTT Low Carbon Finland 2050****** |

Own illustration; *German Federal Ministry for Economic Affairs and Energy (2014): *Gesetz für den Ausbau erneuerbarer Energien*, ** 50Hertz, Amprion, TenneT, TransnetBW (2014): *Szenariorahmen får die Netzentwicklungspläne Strom 2015 – Entwurf der Übertragungsnetzbetreiber*, April 2014, draft – not approved by the German regulator. *** Energinet.dk (2014): *Energinet dk's analyseforudsætninger 2014-2035 - opdatering september 2014*, ****Danish Energy Agency (2013): *Energiscenarier frem mod 2020, 2035 og 2050*, *****Swedish Energy Agency: *Kontrollstation för elcertifikatsystemet 2015*, ****** VTT Technical Research Centre of Finland (2012): *Low carbon Finland 2050*

**Overall RES-E deployment**

Figure 2 and Figure 3 compare assumed RES-E production levels in the two RES-E scenario parameters (Moderate and High RES-E). It should be noted that hydro-power generation in Norway and Sweden is assumed to be the same in both scenarios in 2030. In the High RES-E scenario, wind power production in the Nordic countries corresponds to more than four times the production in 2013.

For Germany (Figure 3) both onshore and offshore wind power generation are projected to heavily increase. In the High RE scenarios, this corresponds to almost 4.5 times the amount of wind power generation seen in 2013.

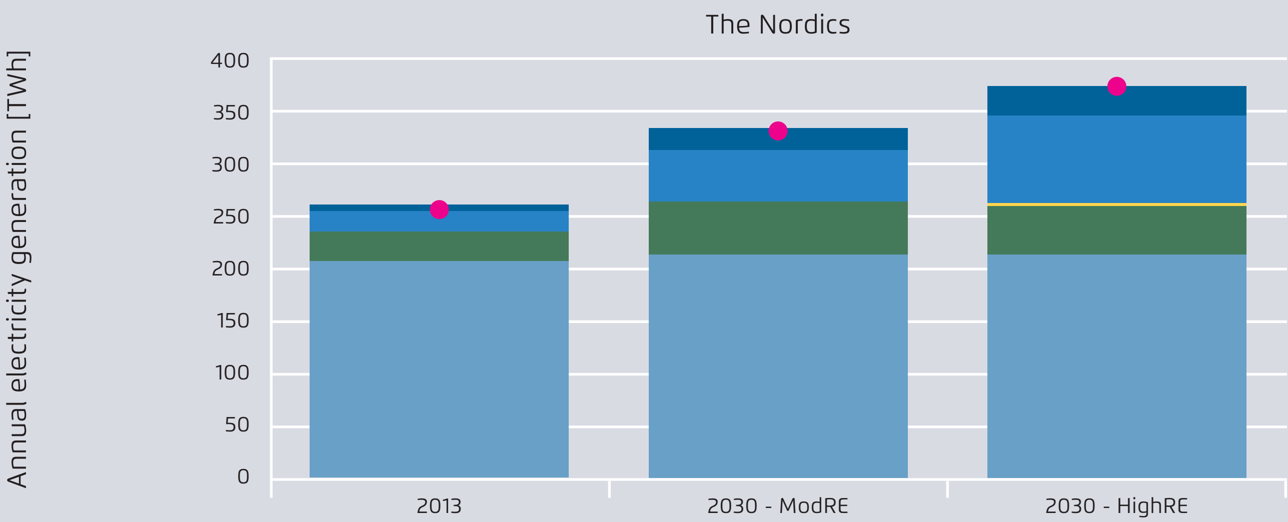
Deployment of new pumped hydro capacity is not included as RES-E capacity in the scenarios' assumptions.

**Power balance by country**

RES-E and nuclear power generation (excluding generation taxes) have very low short-run marginal power generation costs. These power plants will be at the low end of the merit order curve and their maximum production is very likely to be "accepted" in the model simulation. Therefore, the predefined deployment of these technologies indicates a minimum annual generation level in each country.[9] On the other hand, annual generation from other fossil-fuel power plants (lignite and coal) will depend on the simulation result as they are placed higher on the merit order curve. When compared to gross electricity consumption, predefined deployment of RES-E and nuclear power generation indicates a gap to be supplied by conventional fossil fuel based generation or a potential for export. This is illustrated in Figure 4 for the moderate RE scenario.

In the Moderate RE scenarios, Norway, Sweden and Denmark show a positive balance of generation from RES-E and nuclear compared to gross demand. If not used for district heat production within the country, this electricity has to be exported to other countries or, alternatively, reduced if there is an insufficient market for exports. In the Moderate RE scenarios both Finland and Germany are under-supplied on an annual basis in terms of RES-E and nuclear power production alone.

RES-E deployment scenarios and current generation level for the Nordic countries. RES-E deployment levels for the individual Nordic countries are shown in the data report (Ea Energy Analyses and DTU Management (2015): Economic and climate effects of increased integration of the Nordic and German electricity systems – Data report) Figure 2



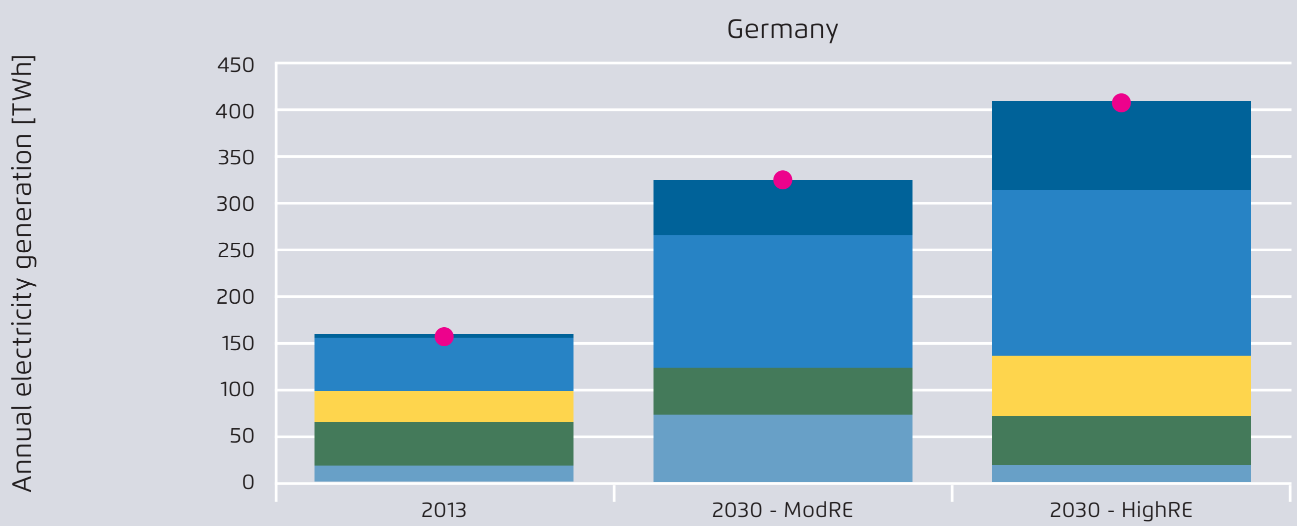

| | 2013 | 2030 - ModRE | 2030 - HighRE |
|---|---|---|---|
| Offshore wind | 5 | 20 | 29 |
| Onshore wind | 21 | 47 | 85 |
| Solar | 0 | 1 | 1 |
| Biomass | 28 | 52 | 47 |
| Hydro | 209 | 216 | 216 |
| Total RE | 263 | 336 | 378 |

Own calculation

In the High RE scenarios, the surplus in Norway and Sweden increases due to additional RES-E generation. In Denmark, additional wind power generation is levelled out in the model runs by lowering production based on biomass (Table 6).[10] In Finland, the total surplus decreases slightly in spite of a doubling of wind power generation. This is the result of the assumption about fewer investments in new nuclear power capacity in the High RE-scenario in Finland. The surplus of generation from RES-E and nuclear sources compared to gross demand (in the following referred to as surplus) by a country should be compared to the maximum possible export volume based on the capacity of international interconnectors. It appears that the systems in both Norway and Sweden are close to, or even beyond, the upper limit in the amount of electricity that can be exported (see maximum exports in the Moderate and High Transmission scenarios shown in Table 6). This is especially apparent when considering that options to export to each respective neighbour (i.e. Norway or Sweden) on an annual basis are limited to the transit of electricity, since the neighbouring country also faces an annual surplus, and so cannot absorb additional electricity. In Table 6 the figures for maximum export discounting transmission lines between Norway and Sweden illustrate this situation. For Norway, the High RE scenarios show a surplus of 33 TWh, while the maximum export capacity without taking Sweden into account is only between 23 and 25 TWh. Looking at the sum for Norway and Sweden, the surplus is around 62 TWh in the High RE scenarios, while the export capacity to other countries ranges from 55 to 65 TWh.

Taking into account the fact that transmission lines will also be used for import – for example, during wind power production peaks in Denmark and Germany – the available annual export volumes will decline further. The reason

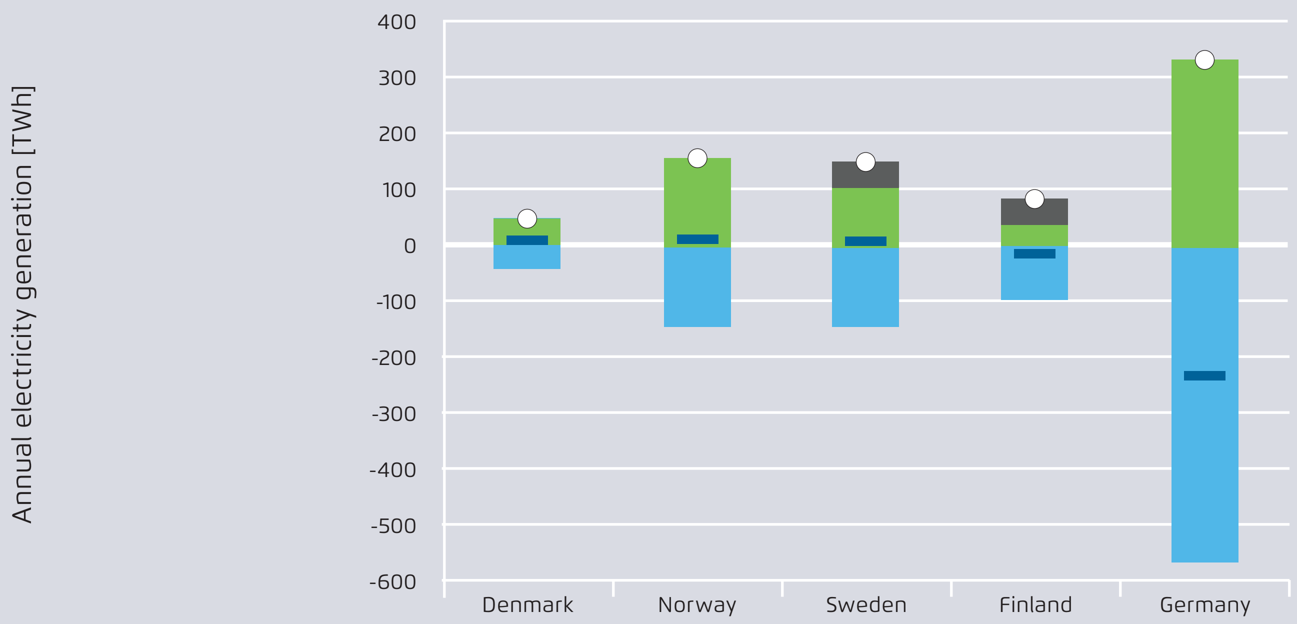
RES-E deployment scenarios and current capacities for Germany — Figure 3




| | 2013 | 2030 - ModRE | 2030 - HighRE |
|---|---|---|---|
| Offshore wind | 2 | 59 | 95 |
| Onshore wind | 59 | 141 | 178 |
| Solar | 32 | 52 | 63 |
| Biomass | 46 | 53 | 53 |
| Hydro | 19 | 20 | 20 |
| Total RE | 158 | 325 | 409 |

Own calculation

Level of RES-E and nuclear power generation in the Moderate RE scenario compared to gross electricity consumption by 2030 (excluding electricity use for district heating production, pumped storage and consumption by power plants). When generation from RES-E and nuclear sources is positive compared to gross demand, the country is oversupplied with electricity from these sources alone. Figure 4




| | Denmark | Norway | Sweden | Finland | Germany |
|---|---|---|---|---|---|
| Elektricity demand | -40 | -139 | -139 | -94 | -552 |
| Potential Nuclear | 0 | 0 | 53 | 48 | 0 |
| Total RE | 48 | 154 | 98 | 37 | 325 |
| Total Nuclear + RE | 48 | 154 | 151 | 84 | 325 |
| Generation from RS-E and nuclear compared to gross demand | 8 | 15 | 12 | -10 | -227 |

Own calculation

for this is that the imported electricity will also need to be exported at other times in the year, further limiting the availability of an interconnector for net export. For example, if a transmission line is used for import ¼ of the year, it will have to be used to export the same amount for another ¼ of the year, given that net export is necessary due to the surplus of domestic generation from RES-E and nuclear. This means that the export capacity would only be available for net export during the remaining half of the year.

The current capacity of interconnectors and assumptions for future development are further explained in section 3.3.

## 3.3 Grid integration

The Nordic electricity system has strong interconnectors between countries. Furthermore, the Nordic countries are connected to Germany and Poland with both alternating current (AC) and direct current (DC) interconnectors. The Nordic countries are one synchronous area, except for Western Denmark, which is synchronous with the European system (UCTE), including Germany and Poland.

Surplus power production from RES-E and nuclear by 2030 compared to export options. All values are given in TWh. Maximum export volumes are based on total export capacity on all transmission lines (average availability of 90 percent during the whole year). The maximum export volume for "w/o Norway/Sweden" indicates maximum export volume without transmission lines to Norway and Sweden. Table 6

| TWh | Denmark | Norway | Sweden | Finland | Germany |
|---|---|---|---|---|---|
| Surplus – Mod RE | 8 | 15 | 12 | -10 | -227 |
| Surplus – High RE | 8 | 33 | 29 | -13 | -143 |
| Max export ModTrans | 35 | 39 | 50 | 15 | 163 |
| Max export HighTrans | 40 | 44 | 60 | 22 | 171 |
| Max export ModTrans w/o Norway/Sweden | 17 | 23 | 32 | 4 | 154 |
| Max export HighTrans w/o Norway/Sweden | 21 | 25 | 40 | 4 | 159 |

Own calculation;

The German electricity system is part of the Continental European grid (UCTE). There are interconnections with all surrounding countries, including the Netherlands, Belgium, Luxembourg, France, Switzerland, Austria, the Czech Republic and Poland. There is also a land connection to Western Denmark. Germany is connected to the Nordic system via DC sea cables to Eastern Denmark and Sweden. The assumptions for the different levels of transmission capacities within the current project are based on the ENTSO-E TYNDP 2014. The capacities include both existing interconnections, projects from TYNDP 2012 and new project candidates from TYNDP 2014. The TYNDP is the most comprehensive compilation of information regarding European electricity grid infrastructure development. It is subject to European regulation and includes an assessment of infrastructure projects based on an approved cost-benefit framework.

The projects mentioned in the TYNDP 2014 are in different stages of development. Some may be under construction; others may be merely under consideration. They all are defined as projects of pan-European or regional significance within the Baltic Sea region, backed by cost-benefit analyses.

The analyses in the ENTSO-E report are based on different visions of European energy policy development, reflecting the two dimensions of European market integration and the speed of policy implementation working towards the Energy Roadmap for 2050. The visions are extreme scenarios for the fulfilment of RES-E targets and European market integration. Two of the scenarios fail to meet the EU 2030 targets, predicting a later catch-up. However, Visions 3 and 4, which were used as base cases in this study's model assumptions, fulfil the 2030 targets, with Vision 4 even reaching 60 percent of RES-E by 2030.

The feasibility of project candidates under the TYNDP has been tested under these very diverse framework conditions. The majority have been proven to have positive effects in at least some if not all of the scenarios. For this reason, the projected capacities were judged as suitable for the purposes of this study.

In this study, two different scenarios for the integration of grids are laid out based on TYNDP 2014: the Moderate Transmission scenario and the High Transmission scenario. They differ in the projected level of transmission capacity within and between the Nordic countries and Germany.

### Internal grid in Germany

For the purposes of this study, Germany is modelled as one price zone in line with the current day-ahead market setup.[11] In reality, internal congestion in the German grid sets limitations on the possible flows across the country. This is managed by counter trading, which is performed by the TSOs after market clearing, which makes sure the system operates within its limits. In treating Germany as one price zone without taking into account the need for counter trading, the model assumes the problem of internal congestion will have been effectively solved by 2030. This will require significant investment in the German grid. If these improvements are not put in place by 2030, the electricity flows modelled in this project will not be fully realisable and the potential benefits are likely to be reduced.

### Moderate grid integration

For the Moderate Transmission scenarios, interconnections within and between the Nordic countries and Germany are based on projects from the TYNDP, which are to be completed by 2020 (Figure 5). No further grid expansions beyond 2020 between or within the core countries are included. Projects within and between neighbouring countries are included, if they are expected to be completed by 2025. Transmission capacity upgrades are expected between Norway and Germany, Denmark and Germany, between the Baltic countries, and to the United Kingdom. The total transmission expansion planned in the region is approximately 47 GW.

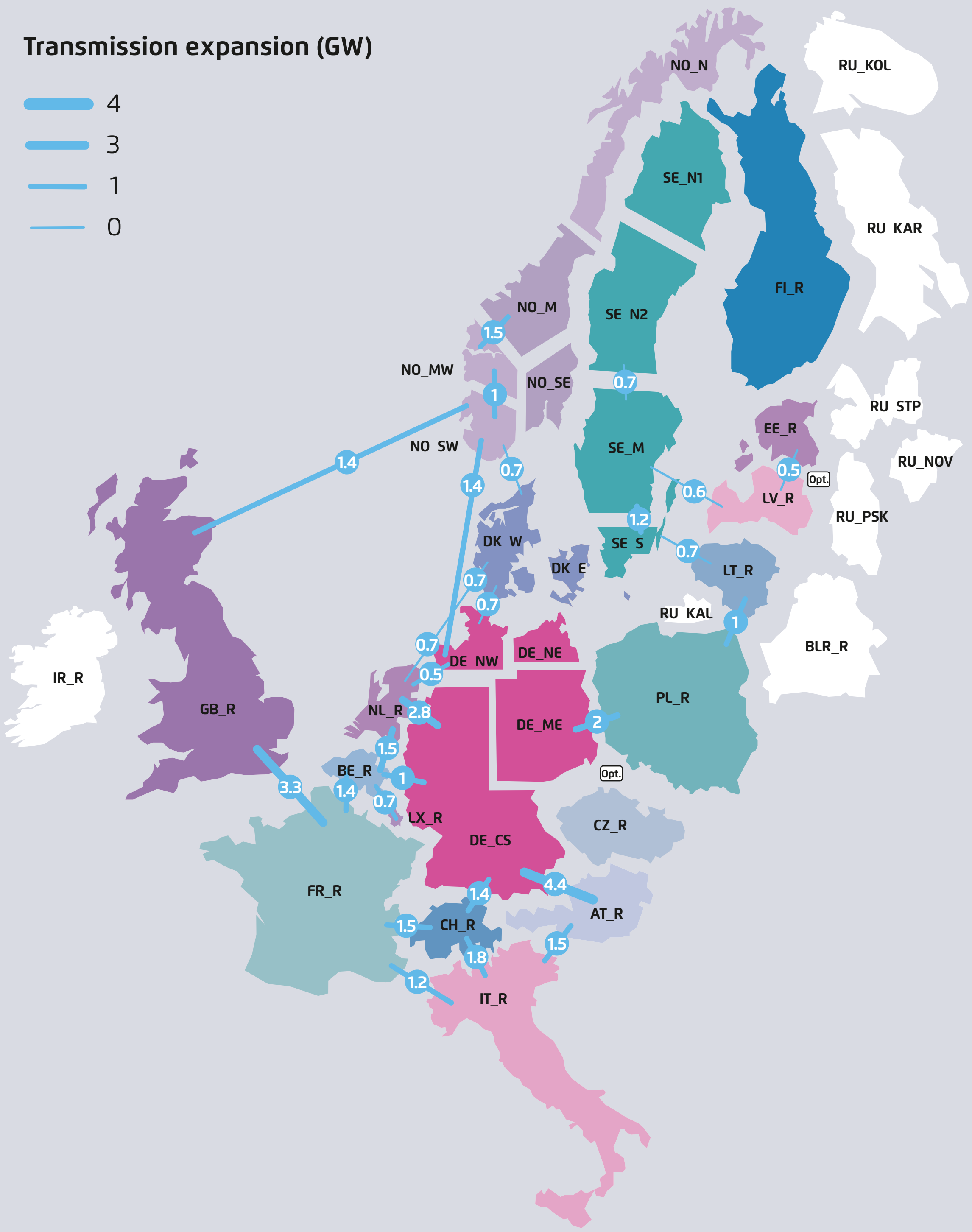
In general, transmission capacities from the TYNDP 2014 have been used in this study, even though realised available trading capacity may prove to be lower. There are, however, a number of differences applied in this study compared to the TYNDP:

- Internal reinforcements in Norway have been estimated based on feedback from the Norwegian Transmission System Operator.
  - Upgrades between NO_M and NO_MW are estimated to give a trading capacity of approximately 1.5 GW. The TYNDP 2014 cites 2.25 GW for the project without specifying on what exact part of the transmission line.
  - Reinforcement between NO_MW and NO_SW is a part of NordLink (Norway to Germany).
- The TYNDP mentions a transmission connection between SE_M and DK_W. Based on feedback from the transmission system operators involved, this line has not been included.
- A new transmission line between Sweden and Latvia is included in the calculations. This project is mentioned as a possible alternative to the Hansa PowerBridge project between Sweden and Germany, which is included in the High Transmission scenario.[12] It should not have been included in the calculations, however, as the project is not meant to be implemented in parallel with the Hansa PowerBridge between Germany and Sweden. However, the effect on the result is assumed to be limited. Additionally, the large surplus of electricity in Norway and Sweden means that the connection could be economically viable, even in parallel with the Hansa PowerBridge project being realised. Not including this transmission line in the calculations would most likely lead to a slightly higher valuation of other transmission lines.
- The TYNDP mentions a possible line between Denmark and the UK (VikingLink) to be completed by 2030. Since this is a connection between a core country and a third country, it has not been included in our calculations, in line with the scenario approach. However, recent an-

11 Germany and Austria are one price zone in the EEX spot market, while Austria is considered as a separate region in the model.

12 The capacity and cost benefit analysis for this project were only mentioned in the draft for the Regional Investment Plan 2014 for the Baltic Sea Region as part of the TYNDP 2014. The final version mentions the project without stating further details.

Additional transmission capacity (compared to 2013) for the scenarios with moderate grid integration. Germany is modelled as one price zone without any internal bottlenecks. Figure 5




Own illustration

nouncements by the Danish system operator Energinet.dk and the British energy regulator OFGEM suggest that completion of the project might be realistically expected closer to 2020. Another link between the Nordic countries and the UK (specifically, between Norway and the UK) is planned to be commissioned in 2020 and is therefore included in the calculations.

- The TYNDP mentions a possible advanced DC connection between Denmark and Germany as part of the development of the Kriegers Flak (Denmark) and Baltic 1 and 2 (Germany) wind farms. At the time this study began, the advanced grid solution had been suspended; both Denmark and Germany are currently planning conventional AC connections to their respective wind farms. A connection between Denmark and Germany via the wind farms is therefore not included in the calculations. However, a connection between the two countries via the offshore wind farms is still an option, e.g. by establishing a back-to-back converter to connect the two systems (Eastern Denmark and Germany are not within the same synchronous area).[13]

### High integration of grids

The High Transmission scenarios are also based on the TYNDP 2014. Unlike the Moderate Transmission scenarios, they include projects planned for commissioning up to 2030 between and within the core countries. Grid capacities from, to and between third countries remain unchanged from the moderate integration scenario.

The scenarios with high grid integration show increased international transmission capacities, such as the connection between Norway and Sweden, and Sweden and Denmark.

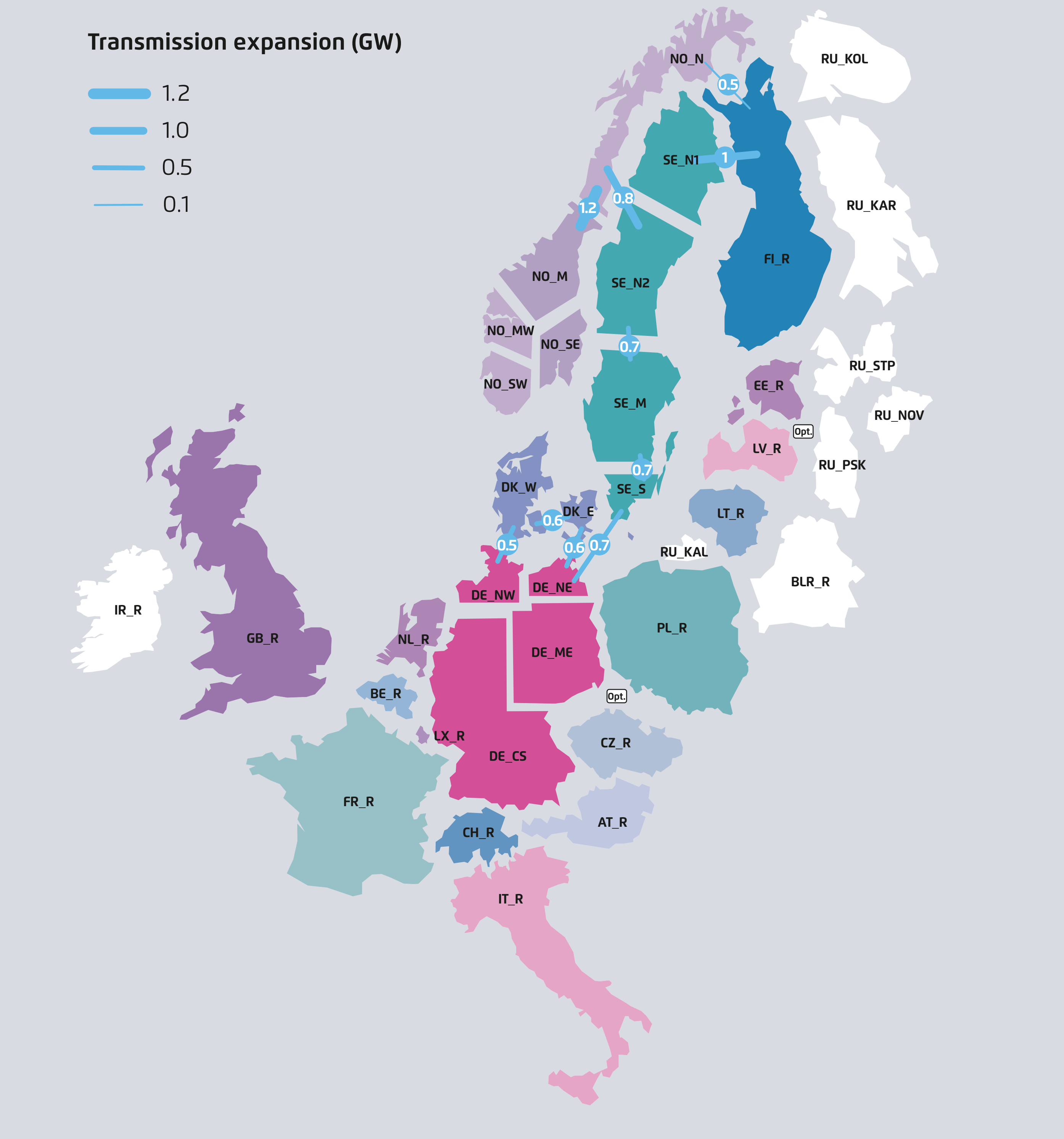
In total, 10 additional transmission projects are included in the High Transmission scenario, adding up to approximately 7.3 GW of transmission capacity within the core countries alone[14] (Table 7). The estimated total costs mentioned in the TYNDP are highly uncertain, and range between €3.6 and €6.0 billion. Depending on the applied lifetime and interest rates this amounts to a cost of between €208 million and €483 million per year. Further internal upgrades to regional systems may be necessary to get the most from these transmission lines; this is especially true for Germany and Finland, which are considered one region in the model. The costs of these internal upgrades are not included in the study's calculations. However, it is important to bear in mind that only the costs of the *additional* internal upgrades enabling maximum capacity in the High Transmission scenarios will affect the scenarios, while the costs of internal upgrades common to both the Moderate and High Transmission scenarios will not affect the economic differences between the scenarios.

13 Energinet.dk (2014): *Systemplan 2014*

14 The transmission expansion of 47 GW mentioned for the Moderate Transmission scenarios also included connection to and within third countries.

Additional transmission capacities in the High Transmission scenarios for 2030 (compared to the Moderate Transmission scenarios). Germany is modelled as one price zone without any internal bottlenecks.

Figure 6




Own illustration

## 4.1 Modelling tool

The quantitative analyses were carried out using Balmorel, which is a partial equilibrium model for determining the lowest cost dispatch for the power system. The model is based on a detailed technical representation of the existing power system, including power and heat generation facilities as well as the most important bottlenecks in the overall transmission grid. The main output of the model is a least cost optimisation of the production patterns of all power units, assuming full foresight of one year concerning all important factors, such as changes in demand, availability

Additional transmission projects in the High Transmission scenarios — Table 7

| Project | From | To | Capacity (MW) | Year | Estimated Cost (€ millions) |
|---|---|---|---|---|---|
| **Core Countries** | | | | | |
| Westcoast | DK_W | DE_NW | 500 | 2022 | 170–210 |
| Hansa PowerBridge | SE_S | DE_NE | 700 | 2025 | 200–400 |
| 3rd AC Finland-Sweden | SE_N1 | FI_R | 1,000 | 2025 | 64–120 |
| Finland-Norway | NO_N | FI_R | 500 | 2030 | 300–700 |
| Norway-North Sweden | NO_N | SE_N2 | 750 | 2030 | 140–330 |
| East Denmark-Germany | DK_E | DE_NE | 600 | 2030 | 500–610 |
| Sum of costs | | | | | **1,374–2,370** |
| **Internal Reinforcements** | | | | | |
| NordBalt Cable Phase 2 | SE_S | SE_M | 700 | 2023 | 170–270 |
| Res in mid-Norway | NO_M | NO_N | 1,200 | 2023 | 870–1,500 |
| Great Belt II | DK_W | DK_E | 600 | 2030 | 390–480 |
| Sweden north-south | SE_M | SE_N2 | 700 | 2030 | 800–1,400 |
| Sum of costs | | | | | **2,230–3,650** |
| **Total cost of High Transmission scenario** | | | | | **3,604–6,020** |
| **Annual cost (4 % interest rate, 30 year lifetime)** | | | | | **208–348** |
| **Annual cost (5 % interest rate, 20 year lifetime)** | | | | | **289–483** |

Own calculation

# 4 Modelling the future energy system

of power plants and transmission lines and RES-E generation patterns. The model, which was originally developed with a focus on the countries in the Baltic region, is particularly effective at modelling combined heat and power production.

In addition to simulating the dispatch of generation units, the model is able to optimise investments in different new generation units (coal, gas, wind, biomass, CCS, etc.) as well as in new interconnectors.

## 4.2 Model setup

Model results are influenced by numerous factors, including the time resolution and investment options. In this project, all final results are based on hourly simulations. However, all hourly simulations are based on investment decisions defined in a preceding model run with an aggregated time resolution (Table 8).
The simulations with an aggregated time resolution are necessary, as endogenous investment decisions cannot be carried out within reasonable computation times at an hourly time resolution. There are a number of challenges when going from a model run with an aggregated time resolution to an hourly time resolution.

- → Electricity prices
  - → The Balmorel model is a general partial equilibrium model. Therefore, all endogenous investments will be economically balanced when all requirements are taken into account. This means that some time slots will show price spikes where the peak load plants

Model simulation setup. Steps 2 and 3 are repeated for all scenarios. Investment decisions for neighbouring countries from the reference are used in the scenario simulations with aggregated time steps and in the hourly simulations. Investment decisions for the core countries as well as derived feed-in premiums and value of hydropower production from the scenario simulations with an aggregated time resolution are used in the hourly simulations. Table 8

| Model run | Time resolution | Output |
|---|---|---|
| 1. Reference | Aggregated | → Investment in neighbouring countries |
| 2. ModRE_ModTrans | Aggregated | → Investment in core countries<br>→ Feed-in premium to achieve annual RE-production<br>→ Value of hydropower production within weeks |
| 3. ModRE_ModTrans_hourly | Hourly | → Annual production patterns<br>→ Electricity prices<br>→ Economic results<br>  → Total cost of system operation<br>  → Value of transmission |

Own illustration

    will secure the income required to satisfy all annual spending.
  - The hourly simulations will treat all capacity as exogenous, meaning that no price spikes due to investment decisions will appear. Therefore, peak load plants will require some additional income in order to show a levelised economy.
- Annual energy restrictions
  - The hourly simulations are implemented by optimising the energy system for one week at a time. This means that these model calculations cannot handle annual restrictions and requirements directly. This is relevant for numerous production types, including annual hydropower production potential and requirements for annual biomass based power production.
  - The investment runs are used to define the value of hydropower production each week. This value is in turn used in the hourly simulation when deciding the amount of hydropower production over one week. As a result, the annual hydropower production can vary slightly from the aggregated model runs.
  - The investment runs are used to define the level of feed-in premiums for power plants contributing to fulfilling an annual requirement. A certain requirement for annual biomass based power production would thus result in a certain level of feed-in premium in the aggregated model run, which in turn is used in the hourly simulation to model power production from biomass units. As a result, total annual production can differ from the aggregated model runs.
- The aggregated model runs are carried out for both 2020 and 2030 in order to get a better picture of investments taking place throughout the year. The hourly simulations are only carried out for 2030.

## 4.3 Generation mix

The assumptions on RES-E deployment in the Nordic countries and Germany lead to an increasing share of RE in the generation mix (Figure 2 and 3). In the ModRE_ModTrans scenario, almost 70 percent of total production is based on renewable sources by 2030, and approximately one-third of all production in the Nordic countries and Germany is based on variable energy sources, i.e. wind and solar power. On top of this, a share of the hydropower production can also be considered a variable resource since it is based on run-of-river power plants.

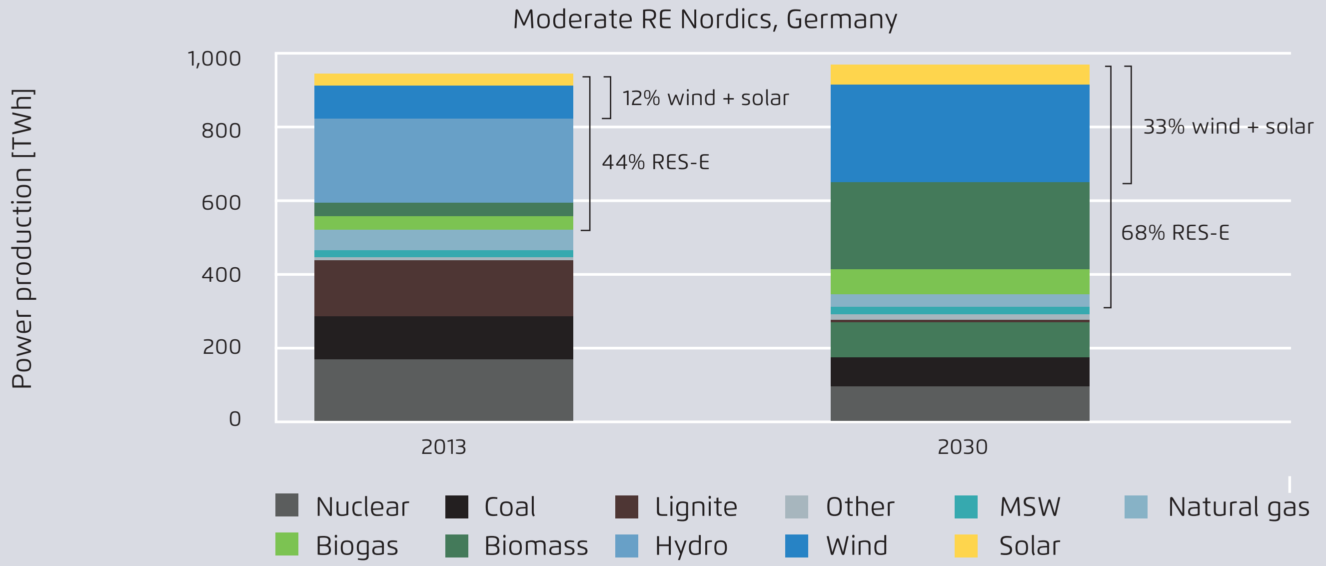
Total production in the Nordic countries and Germany is 974 TWh, whilst total gross demand is 964 TWh (see Figure 1). This excludes electricity use for district heating and losses in pumped hydro stations.

The Nordic system remains dominated by hydropower in 2030, accounting for almost half of total production in 2030 (Figure 8). Another 15 percent comes from solar and wind power, while the rest is based on thermal production, mainly biomass, in addition to nuclear power. The German system is dominated by variable RES-E, accounting for almost half of total production, while thermal production based on both RE and fossil fuels accounts for the other half.

A more detailed look at the Nordic power systems reveals the differences between individual countries (Figure 9). Hydropower generation accounts for almost 90 percent of total generation in Norway and more than 40 percent in Sweden, where nuclear power generation accounts for around one-third of total generation. Finland is dominated by thermal generation, with nuclear power accounting for more than half of total generation; all thermal generation accounts for more than 75 percent. Denmark has the largest share of variable RES-E, with wind and solar power making up more than 55 percent of total generation.
In the High RE scenarios an additional 128 TWh of solar and wind generation is added to the generation mix in the Nordic countries and Germany (Figure 10). At the same time, generation from biomass decreases slightly in Denmark due to the scenario setup with endogenous modelling of the amount of biomass production (see section 3.2). Furthermore, hydropower production is reduced by up to 4 TWh in Norway and Sweden due to limited export capacity.

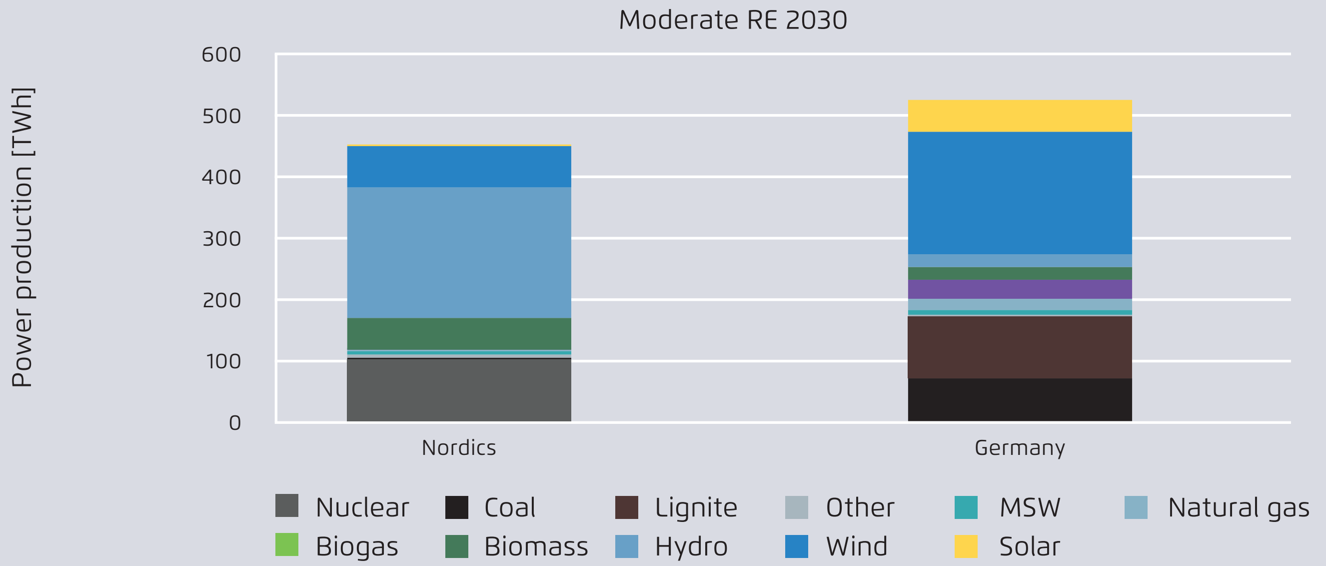
Nuclear power production in Finland is decreased by 10 TWh due to forecasted lower nuclear capacity in the high RE scenarios, while nuclear power production in Sweden

Generation mix in the ModRE-ModTrans scenario. Figure 7




Own illustration

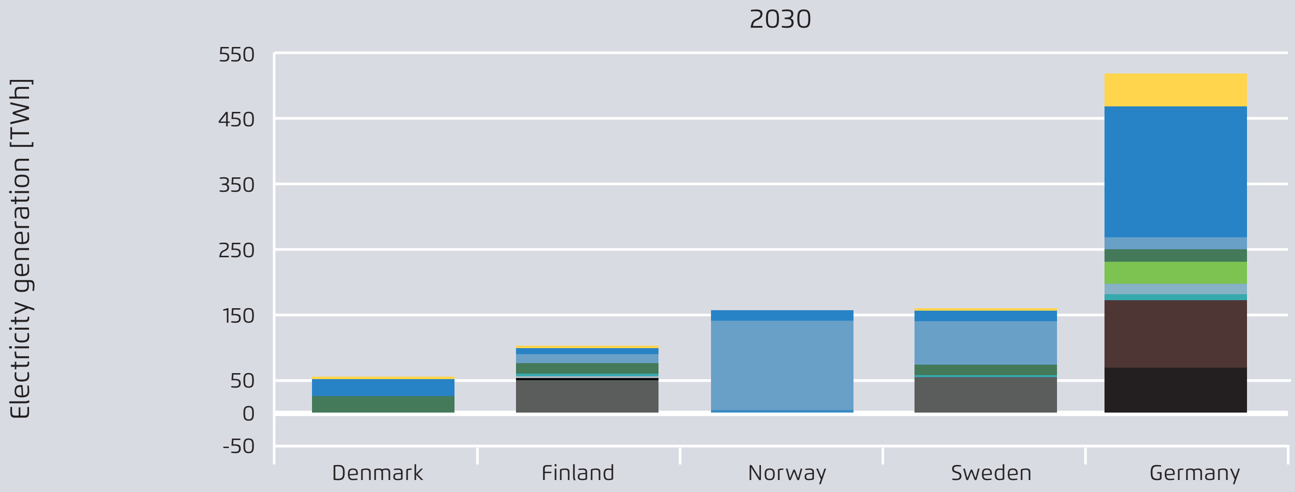
Generation mix by 2030 in the Nordic countries and Germany in the ModRE_ModTrans scenario Figure 8




Own illustration

shows a slight reduction of 2-3 TWh due to limited export capacity. Whether hydro or nuclear power would be reduced in reality in situations with limited export options would depend on the possibility of shutting down nuclear power plants for longer periods. In Germany, generation by thermal fossil-fuel-fired power plants (coal, lignite and

**Generation mix in the core countries in the ModRE_ModTrans scenario** — Figure 9



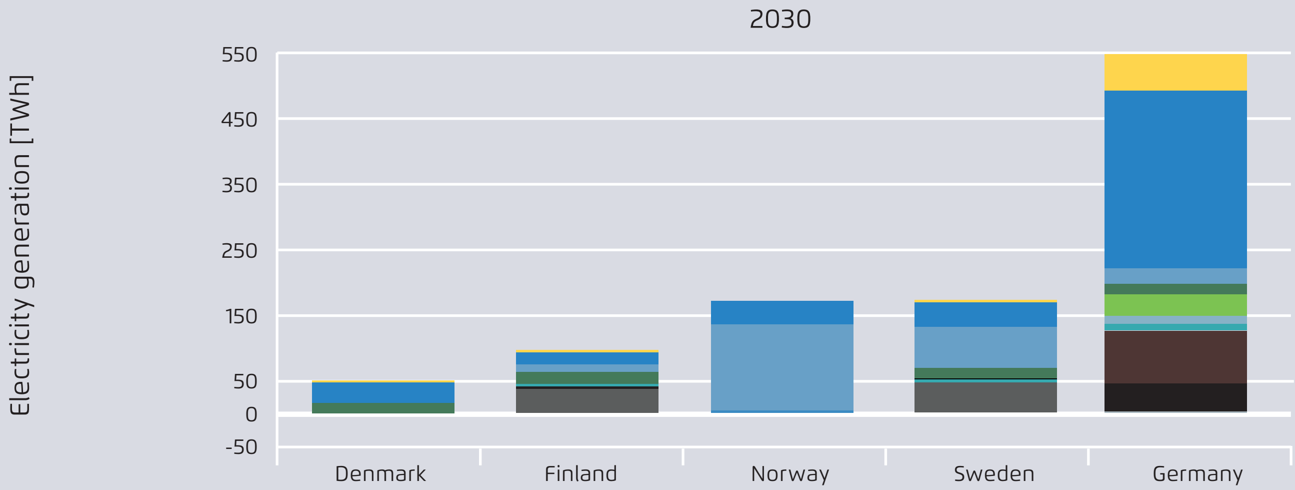

| | Denmark | Finland | Norway | Sweden | Germany |
|---|---|---|---|---|---|
| Solar | 1 | 0 | 0 | 0 | 52 |
| Wind | 27 | 9 | 14 | 17 | 200 |
| Hydro | 0 | 13 | 137 | 64 | 20 |
| Biomass | 19 | 14 | 1 | 17 | 20 |
| Biogas | 1 | 0 | 0 | 0 | 33 |
| Natural gas | 0 | 1 | 2 | 0 | 17 |
| MSW | 2 | 2 | 0 | 2 | 8 |
| Other | 0 | 3 | 0 | 0 | 2 |
| Lignite | 0 | 0 | 0 | 0 | 102 |
| Coal | 0 | 4 | 0 | 1 | 70 |
| Nuclear | 0 | 47 | 0 | 53 | 0 |

Own calculation

natural gas) is reduced by 47 TWh in total. Overall, total electricity generation within the region increases by roughly 50 TWh.

The generation mix is only slightly affected by adding more transmission capacity in the High Transmission scenarios (Figure 11). However, fossil fuel based power production in Germany is reduced by approximately 3 TWh, while hydro production in Norway increases by approximately 1.5 TWh. In Denmark, higher electricity prices (see also section 4.5) make biomass-fired power plants more competitive, increasing production by 0.8 TWh.

Generation mix in the core countries in the HighRE_ModTrans scenario — Figure 10




| | | | | | |
|---|---|---|---|---|---|
| Solar | 1 | 0 | 0 | 0 | 63 |
| Wind | 31 | 16 | 32 | 34 | 273 |
| Hydro | 0 | 13 | 135 | 62 | 20 |
| Biomass | 15 | 14 | 1 | 17 | 18 |
| Biogas | 0 | 0 | 0 | 0 | 34 |
| Natural gas | 0 | 0 | 1 | 0 | 11 |
| MSW | 2 | 2 | 0 | 2 | 8 |
| Other | 0 | 1 | 0 | 0 | 2 |
| Lignite | 0 | 0 | 0 | 0 | 79 |
| Coal | 0 | 3 | 0 | 0 | 50 |
| Nuclear | 0 | 37 | 0 | 50 | 0 |

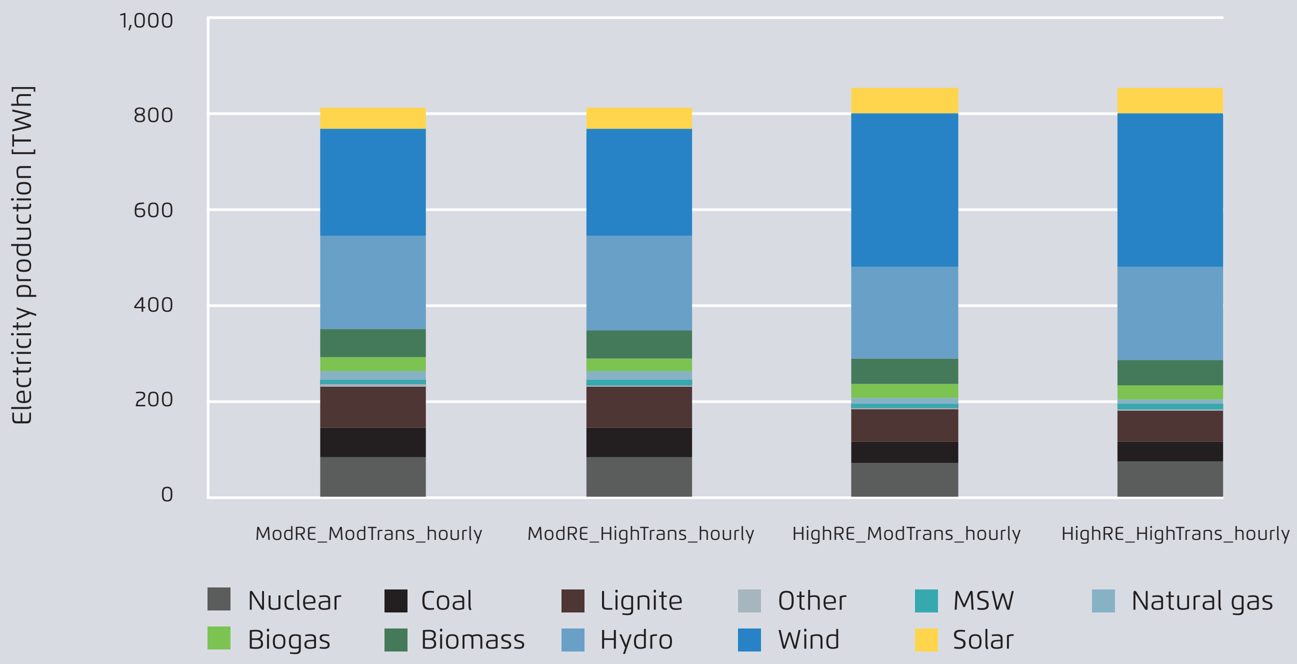
Own calculation

## 4.4 Climate effects

**European ETS and modelling $CO_2$-emissions**

The study uses a fixed $CO_2$ price to determine the values of greenhouse gas emissions. This fixed price is based on the New Policies Scenario from the IEA's World Energy Outlook 2013, and is the same for all scenarios, regardless of the $CO_2$ emissions in the energy sector. Within Europe, $CO_2$ emissions from the power industry are regulated by the European Emissions Trading System (ETS), which according to current rules will run until 2020. The European Commission is currently discussing reforms to the

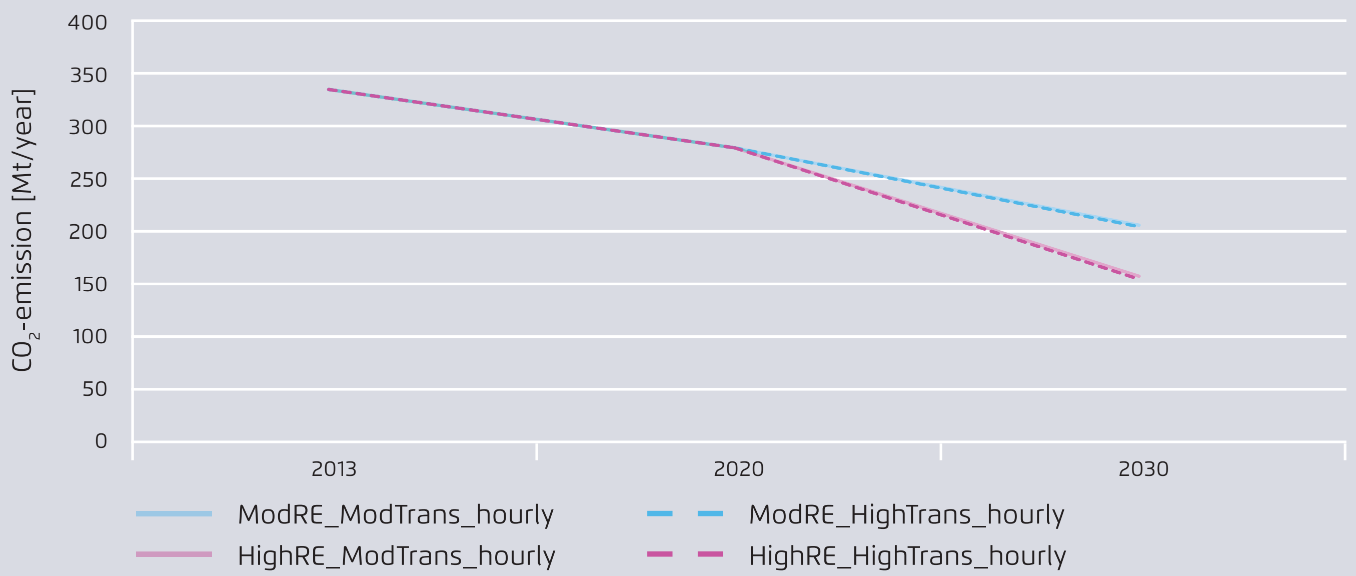
Generation mix in the Nordic countries and Germany in the four different scenarios — Figure 11




Own illustration

ETS and the framework for the trading period from 2021 to 2030. Most fossil-fired power plants (with the exception of power plants with a thermal input capacity below 20 MW) in Europe are included in the ETS, and have to require quotas corresponding to their emissions. In the short run, $CO_2$ savings in one area will lead to lower $CO_2$ prices, while $CO_2$ emissions stay at the same level due to higher emissions somewhere else in the system. In this way, the total level of $CO_2$ emissions is subject to a political decision, not to system optimisation. One could argue that different scenarios for the future power system cannot, therefore, lead to different levels of $CO_2$ emissions at the same $CO_2$ price. However, when evaluating the effect of long-term scenarios on the future development of the power system, it can be beneficial to allow for different levels of $CO_2$ emissions. In this case, the $CO_2$ price represents the cost to society of emitting greenhouse gases. Scenarios with lower $CO_2$ emissions can be used to demonstrate ways in which legislation can be improved towards a less carbon intensive power sector, and can ultimately be used to set a lower emissions cap in the ETS. Since this study is used for an analysis of the effect of physical changes in the power system, and not an analysis of different policies affecting $CO_2$ emissions, we decided to use a fixed $CO_2$ price.

$CO_2$ emissions in the Nordic countries and in Germany in the four scenarios. Figure 12




Own illustration

**$CO_2$ emissions**

The deployment of RES-E in the Nordic countries and Germany leads to a significant reduction in $CO_2$ emissions towards 2030 of between 40 percent and 55 percent compared to 2013 in the electricity and heat sectors (Figure 12). Compared to this, the addition of extra transmission capacity has a relatively limited effect. In the Moderate RE scenario, additional transmission capacity leads to a reduction of 0.7 percent compared to the Moderate Transmission scenario. This increases to a reduction of 2.1 percent in the HighRE_HighTrans scenario compared to the HighRE_ModTrans scenario.

The $CO_2$ savings are robust to changes in neighbouring countries, meaning they are not offset by increasing $CO_2$ emissions in the surrounding countries (Table 9). In this way, emissions from fossil-fired power plants are actually avoided rather than simply moved from Germany and the Nordic countries to other countries. In the Moderate RE scenario, the additional $CO_2$ savings are mainly attributed to increased power production from biomass in Denmark as well as increased wind power production in Norway. In general, the Nordic countries experience a small increase in electricity prices, leading various types of power production to become more competitive, including biomass combined heat and power (CHP). In Norway, increased grid integration enables wind power capacities to be located further north, where wind resources are better. In the High RE scenarios, the additional transmission capacity leads to reduced curtailment of hydropower in Norway, enabling an additional 2 TWh of hydropower production. Furthermore, wind power production in both Norway and Sweden is slightly higher in the High Transmission scenario due to placement of wind power capacity in better wind resource locations. Thus, the total $CO_2$ reduction effect is greater when additional transmission capacity is added to the High RE scenario.

$CO_2$ savings from adding additional transmission capacity — Table 9

| | Moderate RE | | High RE | |
|---|---|---|---|---|
| | Mt/year | % | Mt/year | %/year |
| Nordic countries + Germany | -1.5 | -0.7 % | -3.3 | -2.1 % |
| Surrounding countries | -0.3 | -0.1 % | -1.5 | -0.5 % |
| Nordic countries, Germany and surrounding countries | -1.8 | -0.3 % | -4.9 | -1.1 % |

Own calculation

## 4.5 Wholesale electricity prices

The electricity prices determined in the model simulations represent the short run marginal power production costs of marginal units in the different regions during each time period. The prices do not include any tariffs, taxes or levies, and therefore do not represent the full prices paid by consumers.

The different available power generation resources and levels of RES-E production lead to differences in electricity prices across the region (Figure 13). Northern Scandinavia is dominated by hydropower and enjoys relatively low prices, while the thermal dominated systems in continental Europe and the UK show higher prices. This illustrates the potential economic benefits of increasing transmission between regions. The numbers next to the transmission lines in the diagram indicate the net annual energy flow between regions (TWh), going from areas with lower prices to areas with higher prices.

The prices in the Moderate RE scenario with high transmission capacity are illustrated on Figure 14. The price pattern is similar to the Moderate Transmission scenario, but more balanced, with smaller differences between the price levels in Germany and the Nordic countries.

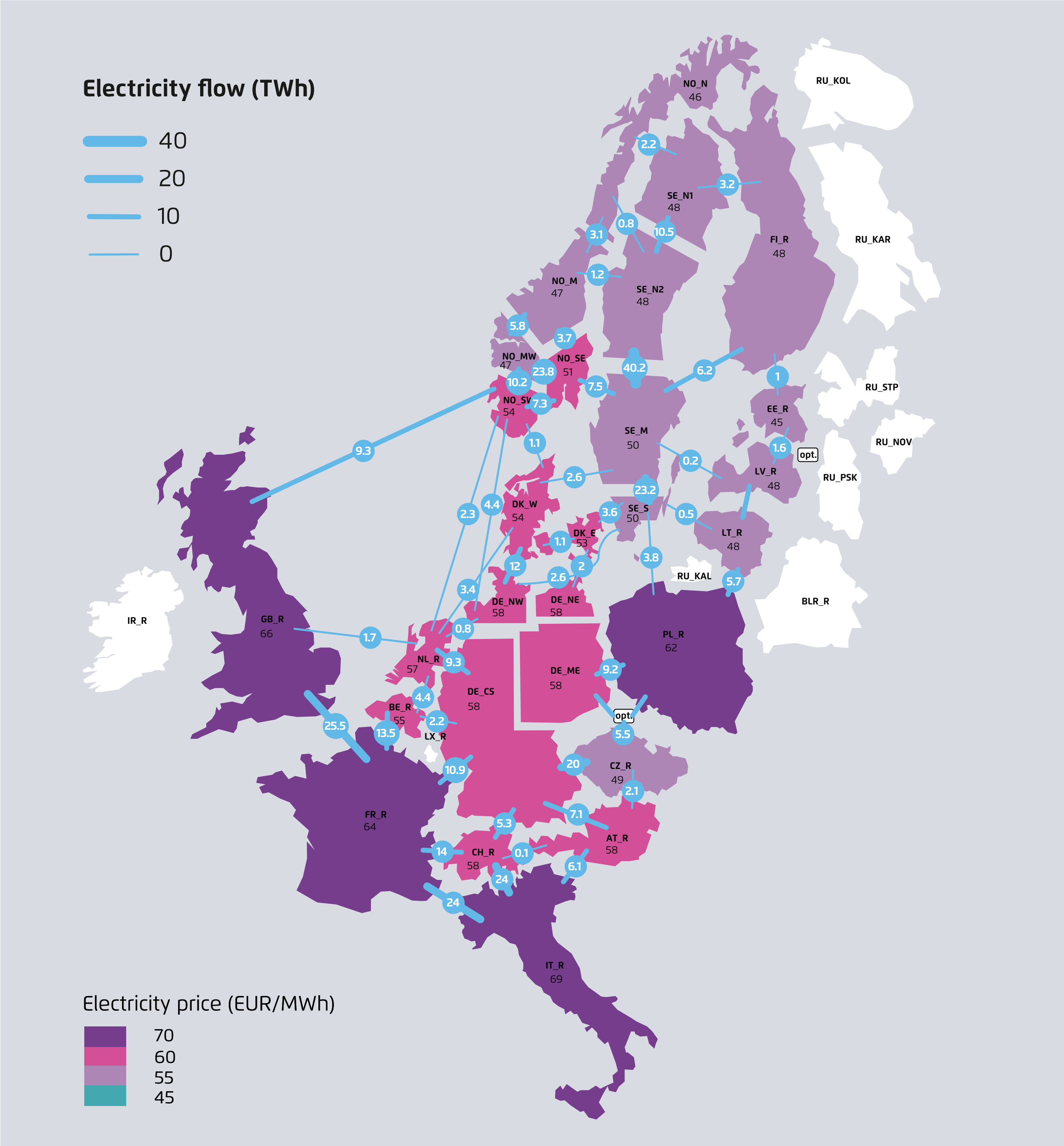
Figure 15 and Figure 16 show the prices in the High RE scenarios.

Electricity prices are affected by both the level of RE and transmission capacity (Figure 17). In general, the additional transmission capacity in the High Transmission scenarios leads to better market integration between the Nordic countries and continental Europe, and thus to higher average prices in the Nordic countries and lower average prices in Germany. This reflects the fact that more electricity can be transmitted from the low price areas in the Nordic countries to Germany.

This is even more pronounced in the High RE scenarios, in which electricity prices drop sharply in the Nordic countries due to the increased amounts of RES-E. At times, the available hydropower production in these scenarios is curtailed, leading to very low power prices, especially in Central- and Northern Norway. Additional transmission capacity leads to higher power prices, albeit still significantly lower than in the Moderate RE scenarios. The very low power prices in the High RE scenarios indicate that the sustainability of the high RE price levels is questionable considering the present transmission system, and that additional expansion of transmission capacity may be economically beneficial. The greater difference between the price levels in the Nordic region and Germany in the

Average annual electricity prices in the ModRE_ModTrans scenario indicated by colour.
The lines indicate the annual flow between regions.

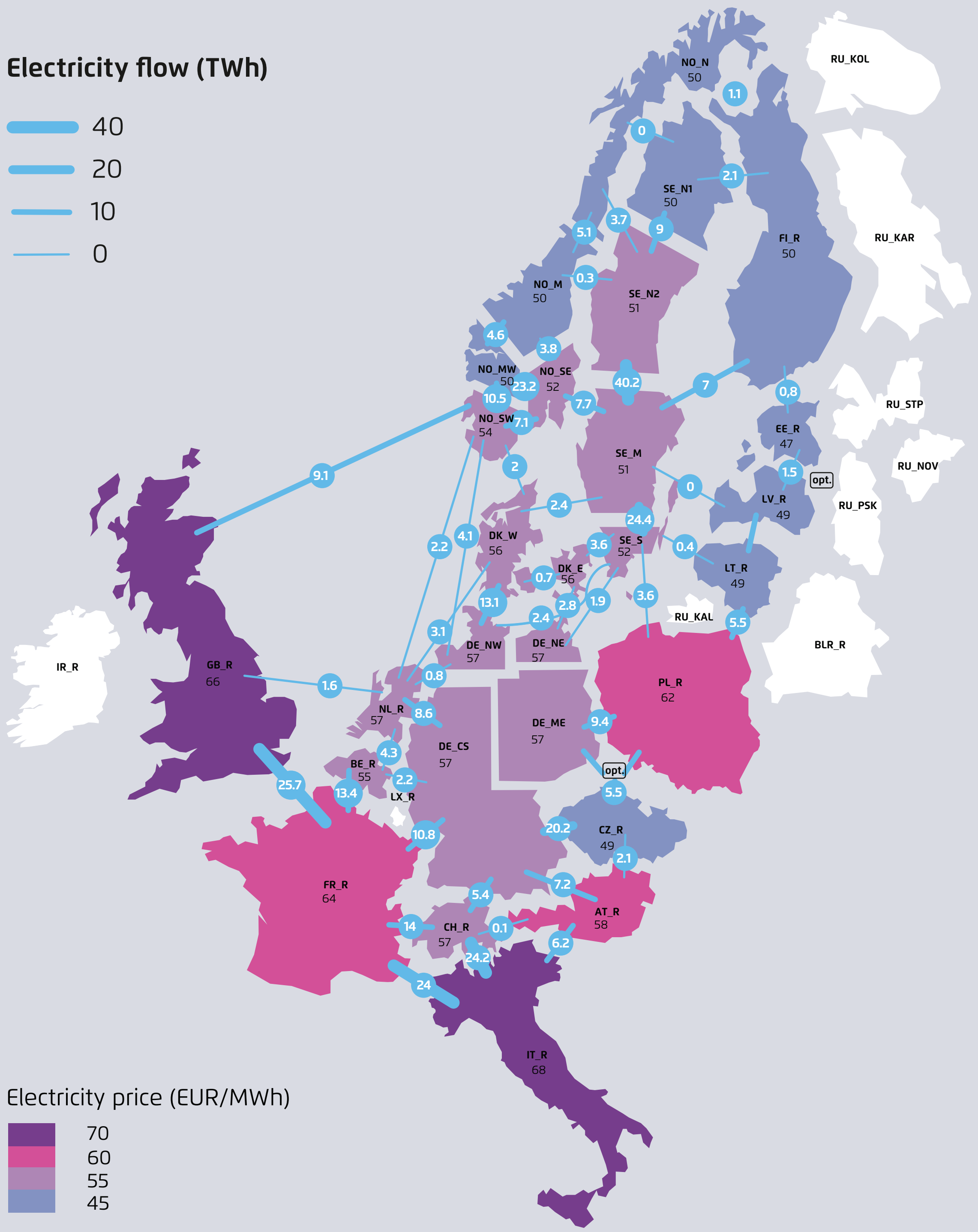
Figure 13




Own illustration

Average annual electricity prices in the ModRE_HighTrans scenario indicated by colour.
The lines indicate the annual flow between regions.

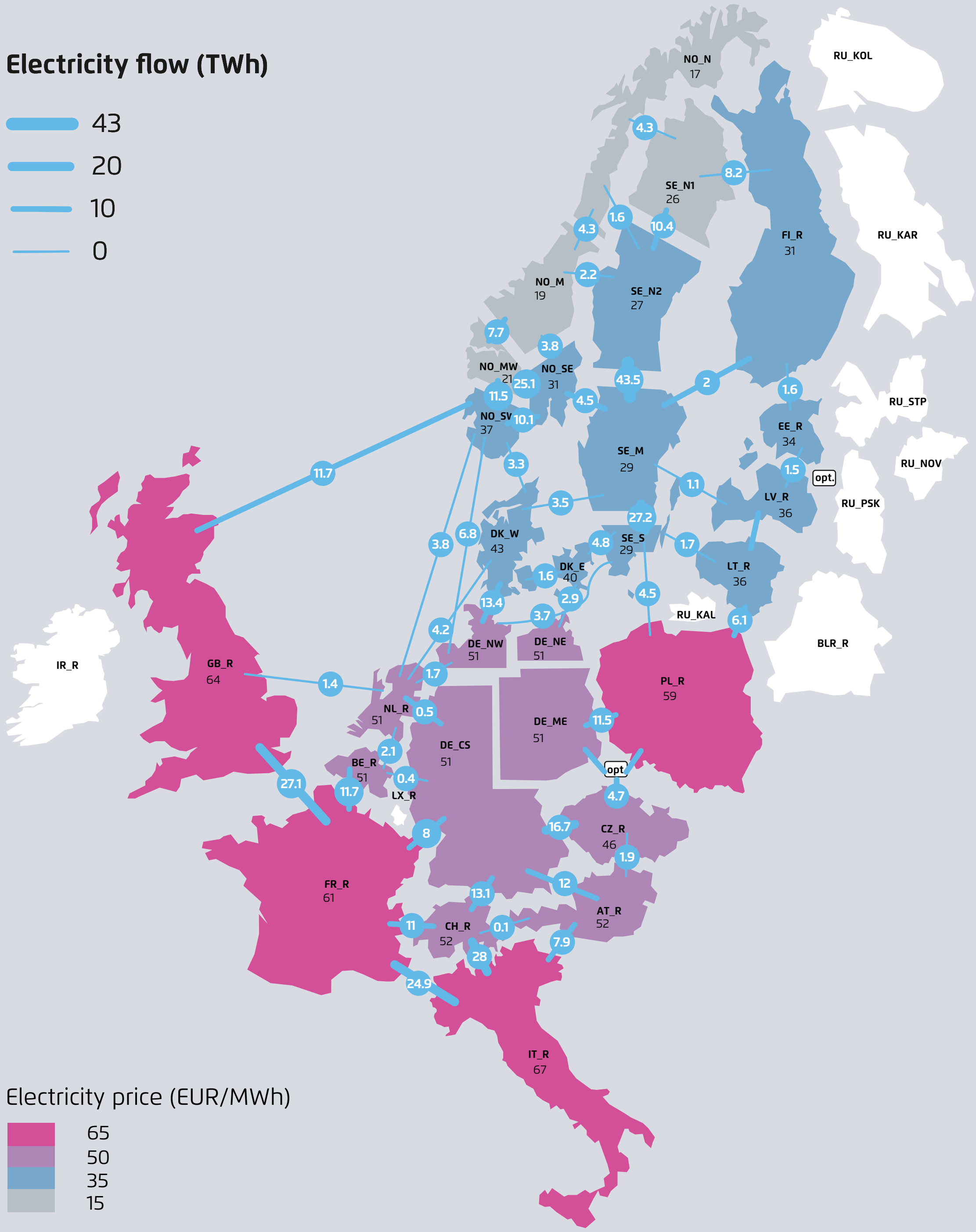
Figure 14




Own illustration

Average annual electricity prices in the HighRE_ModTrans scenario indicated by colour.
The lines indicate the annual flow between regions.

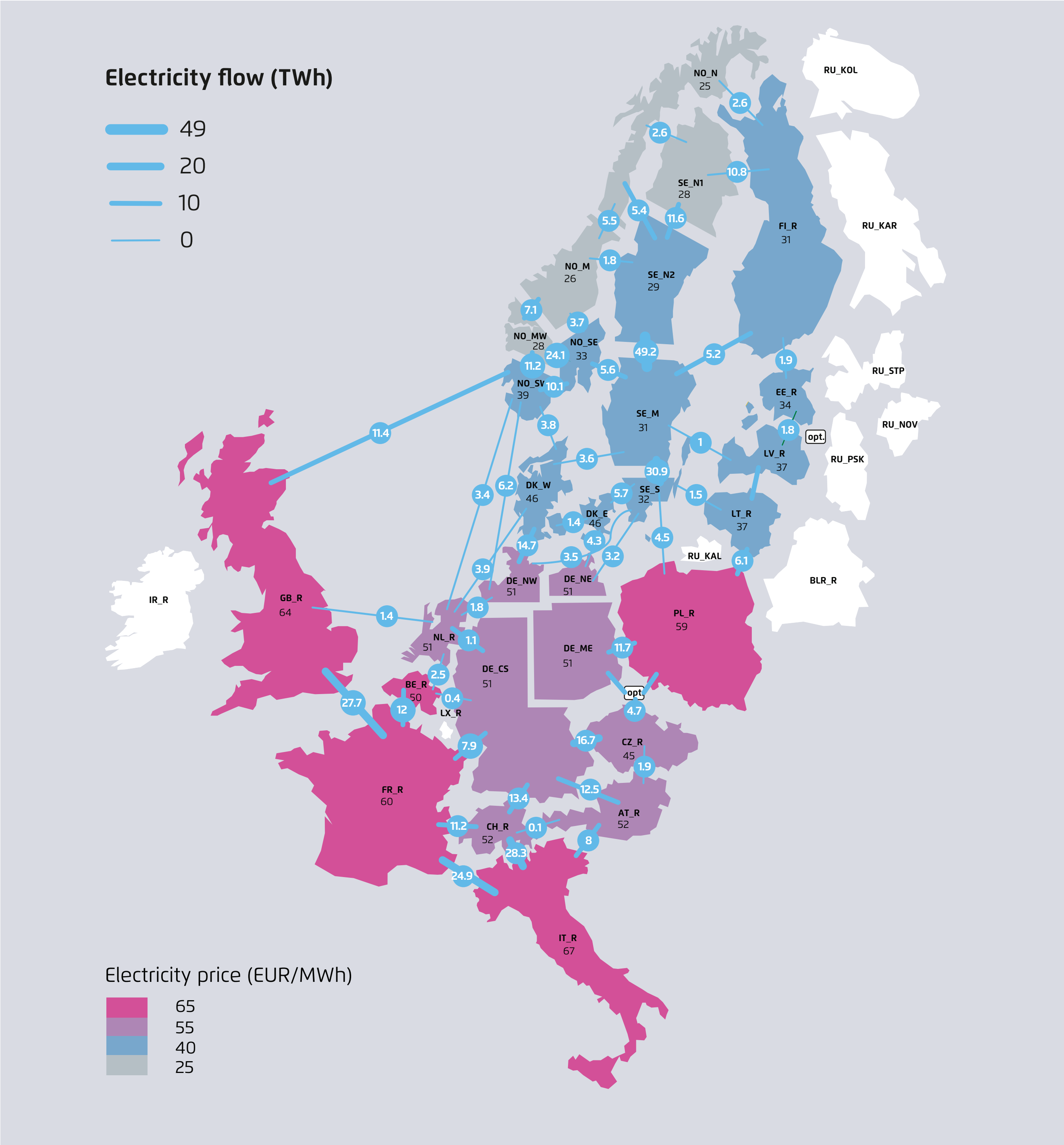
Figure 15




Own illustration

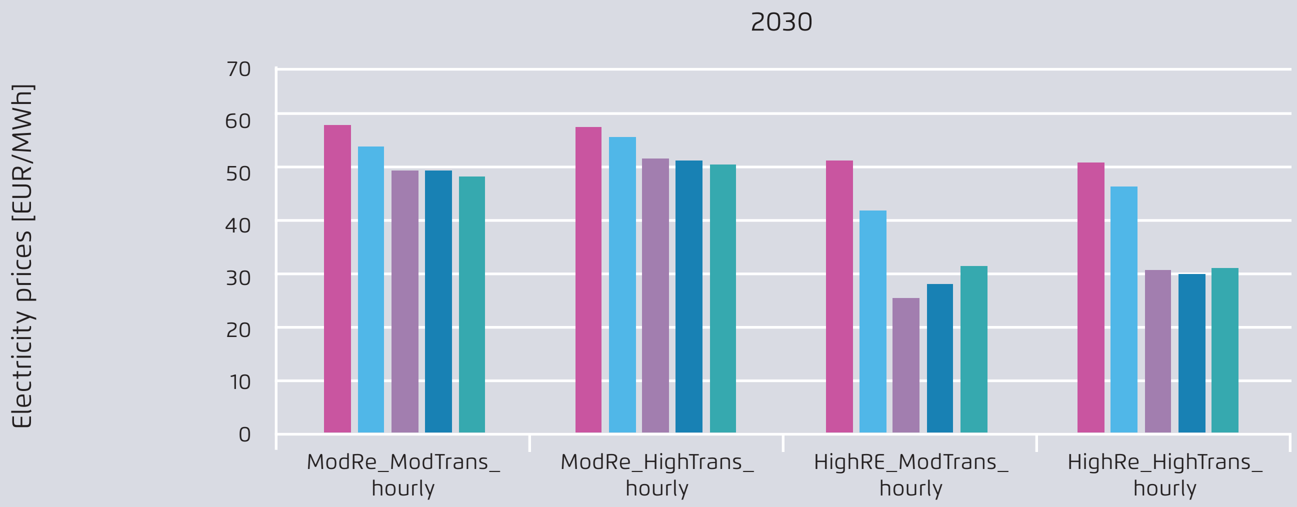
Average annual electricity prices in the HighRE_HighTrans scenario indicated by colour. The lines indicate the annual flow between regions.

Figure 16




Own illustration

Average annual wholesale electricity prices. Wholesale price level for countries as a simple average across regions. (Note that wholesale electricity prices are not consumer prices, which include additional costs such as taxes, levies and distribution fees). Figure 17




| | ModRe_ModTrans_hourly | ModRe_HighTrans_hourly | HighRE_ModTrans_hourly | HighRe_HighTrans_hourly |
|---|---|---|---|---|
| Germany | 58 | 57 | 51 | 51 |
| Denmark | 54 | 56 | 42 | 46 |
| Norway | 49 | 51 | 25 | 30 |
| Sweden | 49 | 51 | 28 | 30 |
| Finland | 48 | 50 | 31 | 31 |

Own calculation

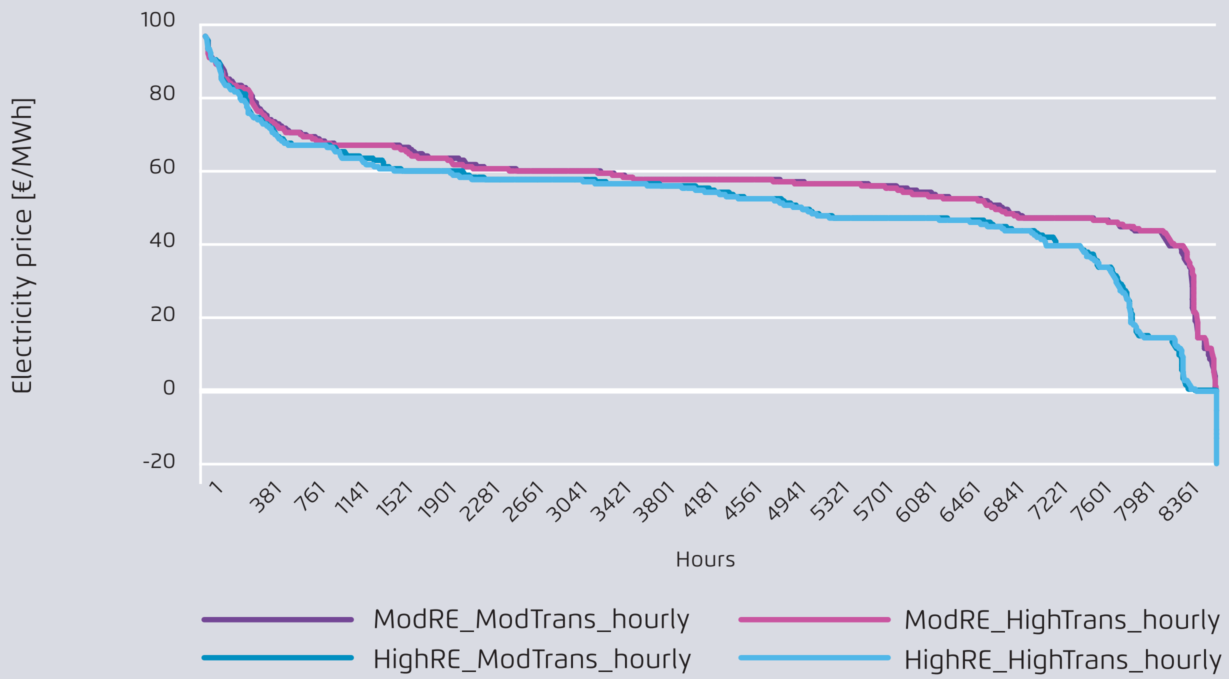
High RE scenarios also shows the increased potential for electricity trade if more RE is integrated into the system.

Electricity prices are highly dependent on assumptions regarding fuel prices, $CO_2$ prices and market setup (e.g. capacity markets and RE subsidy levels). The study uses a $CO_2$ price of 26 EUR/tonne for 2030; RE levels are driven by this $CO_2$ price and additional subsidies. If the RE deployment were driven by higher $CO_2$ prices alone, power prices would be forced to rise. Capacity markets are not included in this assessment.

Electricity prices vary considerably throughout the year, reflecting variations in demand and generation from variable renewable energy sources. This variation can be illustrated using duration curves showing the number of hours a price spends above a certain level. The shape of the duration curves is affected by the generation mix in terms of RES-E levels and transmission options to neighbouring regions, among other factors. This is illustrated for Germany for each of the different scenarios (Figure 18). The scenarios with a higher level of RES-E show more hours at lower prices compared to the scenarios with a moderate level of RES-E. At the same time, transmission capacities tend to lead to fewer price variations, resulting in slightly higher prices at the low end, and slightly lower prices at the high end of the duration curve.

The shape of the duration curves for electricity prices also differs between regions (Figure 19). It is apparent that the hydro-dominated systems in Norway and Sweden are better placed to even out prices at the low end of the curve, having fewer hours with very low prices.

Duration curves for electricity prices in Germany in each of the four different scenarios — Figure 18




Own calculation

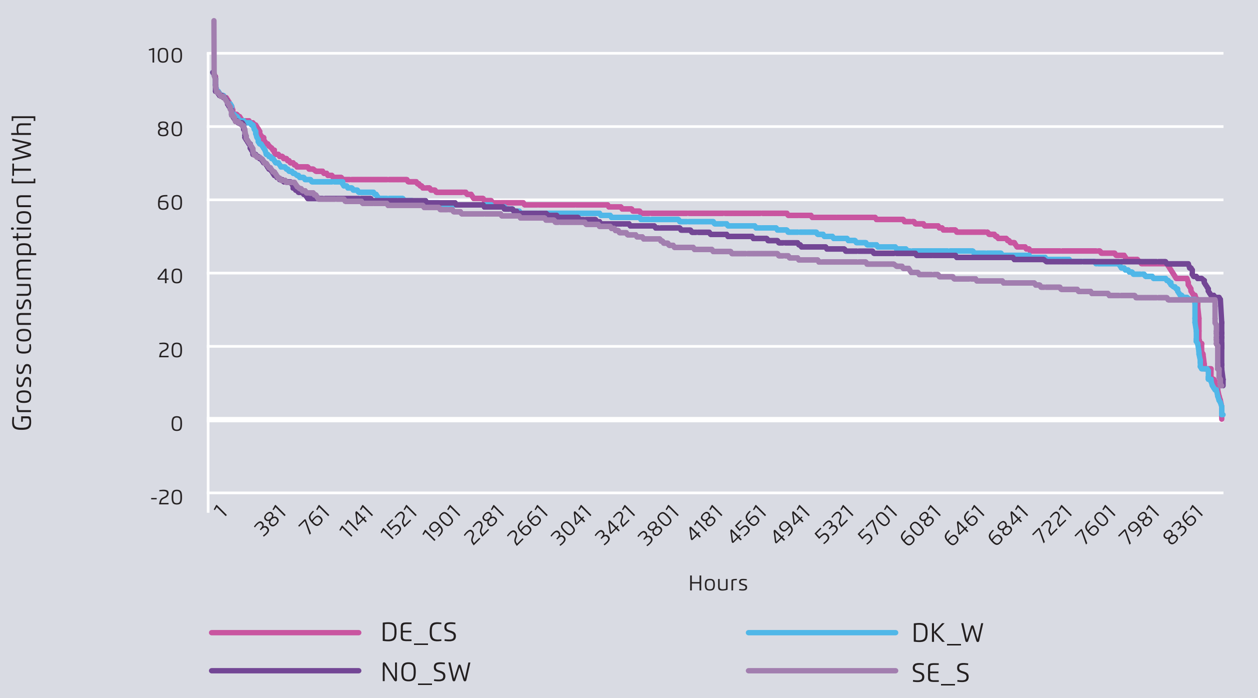
In addition to average electricity prices, the hourly variation in the price spread between two regions is of major importance to electricity trading. Two regions can have a high trade potential at the same annual average price level, provided high and low prices occur at *different times*. As an example, Figure 20 shows the duration curve for the price spread between southern Norway and Germany. In the moderate RE scenarios prices are lower in Norway for around 6,200 hours, increasing to approximately 7,000 hours in the High RE scenarios. This also means that the main flow direction is from Norway to Germany; the connection between the two countries is mainly used for export, and to a lesser extent for balancing the German wind power surplus in Norway.

However, even stopping or reducing imports from Norway to Germany can help to balance wind power, even though the flow direction is not going north. This is true when there is a certain level of import from Norway to Germany. When wind power production in Germany increases, these imports can be reduced or stopped to balance the rise in wind power production.

In the Moderate RE scenarios prices are lower in Germany than in Norway for around 2,000 hours per year, while this is reduced to approximately 1,100–1,400 hours per year in the High RE scenarios. The reduced number of hours with lower prices in Germany shows the increased potential for exports to Norway, leading to lower average prices. In all scenarios, electricity prices are equal in Germany and Norway for around 400–450 hours a year.

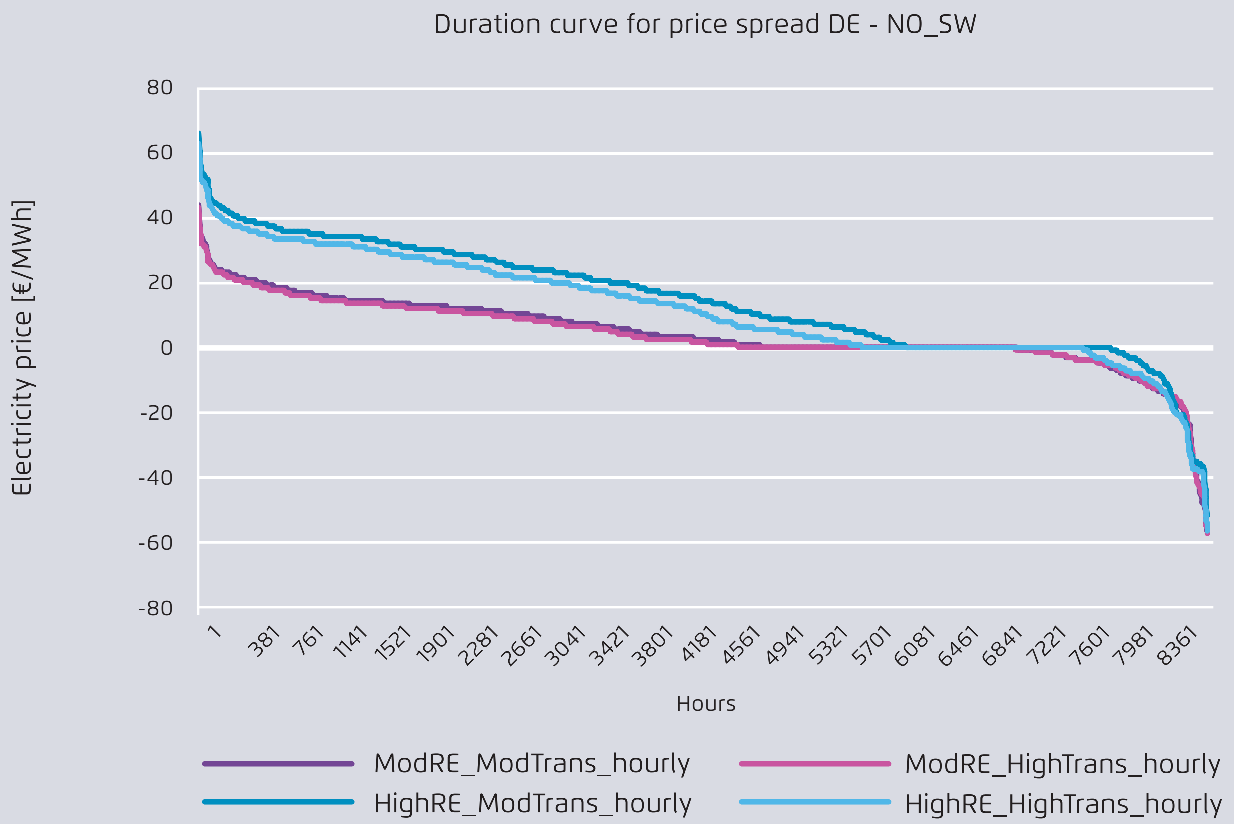
Duration curves for electricity prices in selected regions in Germany, Denmark (DK_W), Norway (NO_SW) and Sweden (SE_S) for the ModRE_ModTrans scenario

Figure 19




Own calculation

Price spread between southern Norway and Germany in each of the four scenarios. Positive values indicate a higher price in Germany than in Norway. The duration curve for the price spread between Germany and southern Sweden shows the same shape, but features a slightly higher number of hours with lower prices in Sweden. Figure 20




Own calculation

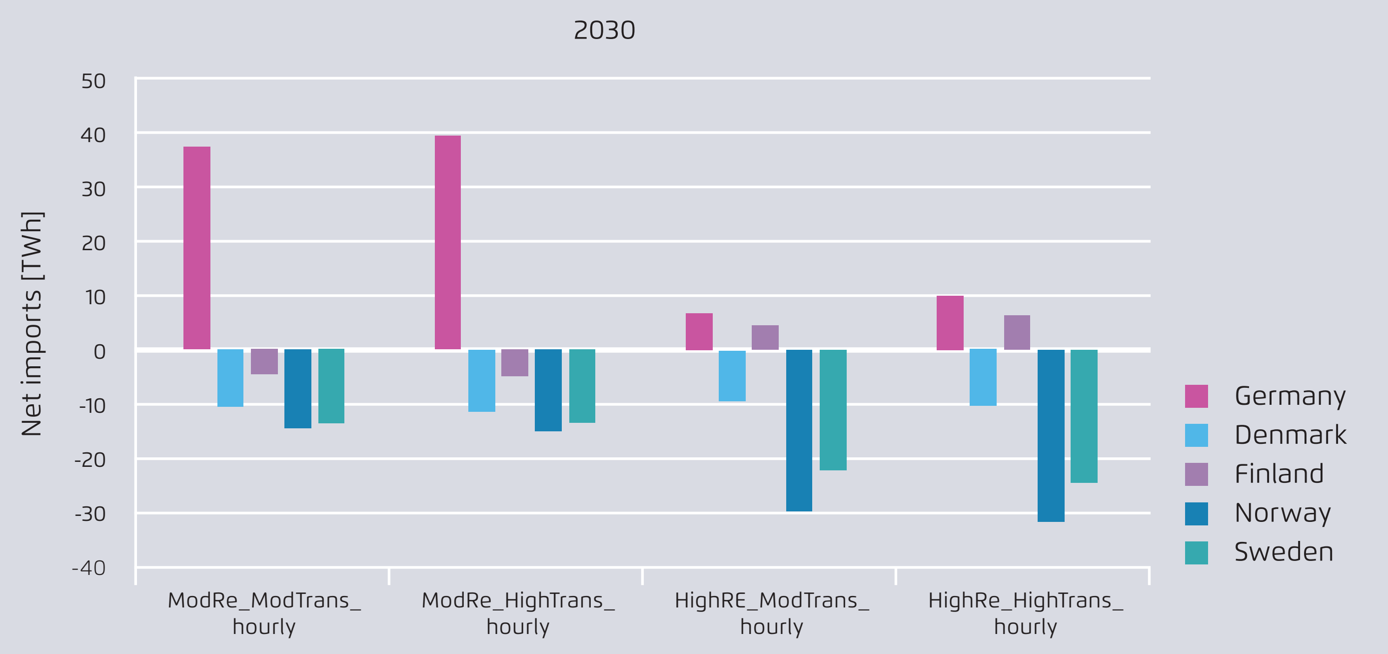
## 4.6 Electricity flow

### Net flows

In the Moderate RE scenarios, all Nordic countries are net exporters of electricity, with Norway and Sweden being the largest contributors at 13-14 TWh/year (Figure 21). In the High RE scenarios, exports from Norway and Sweden increase to 51-56 TWh in total, while exports from Denmark remain stable at approximately the same level, and Finland becomes a net importer due to lower levels of electricity generation from domestic nuclear power. Germany is a net importer of electricity in all scenarios, but the amounts are significantly reduced from almost 40 TWh in the Moderate RE scenarios to less than 10 TWh in the High RE scenarios. This is due to the significant expansion of renewable energy in Germany. The individual export flows via each transmission line are illustrated in Figure 13 to Figure 16.

The net import levels to the different countries are a result of model optimisation and not are defined exogenously. However, required levels of RES-E generation and nuclear power plant capacity have a significant impact on the results, as discussed regarding the power balance of the individual countries in section 4.2. The level of fossil-fired power production as well as RES-E determines the level of imports to Germany. The study has not allowed for new investments in coal fired power capacity beyond exist-

Net annual import to the Nordic countries and Germany in each of the four scenarios. Imports include imports from other surrounding countries. Figure 21




Own calculation

ing plans in Germany, as they were judged too politically difficult to implement. However, new coal-fired capacity is included in the calculations for neighbouring countries, and, without restrictions, some of that capacity might have been established in Germany, thereby reducing imports or even making Germany a net exporter. The same is true for natural gas-fired power plants: if national incentives to establish and operate natural gas power plants are put in place, this will affect the annual power balance, leading to lower imports or even to net exports.

Taken as a whole region, Germany and the Nordic countries combined are a net exporter in all scenarios, ranging from 4 TWh/year in the Moderate RE scenarios to almost 50 TWh/year in the High RE scenarios (exports are shown as negative numbers in Figure 21).

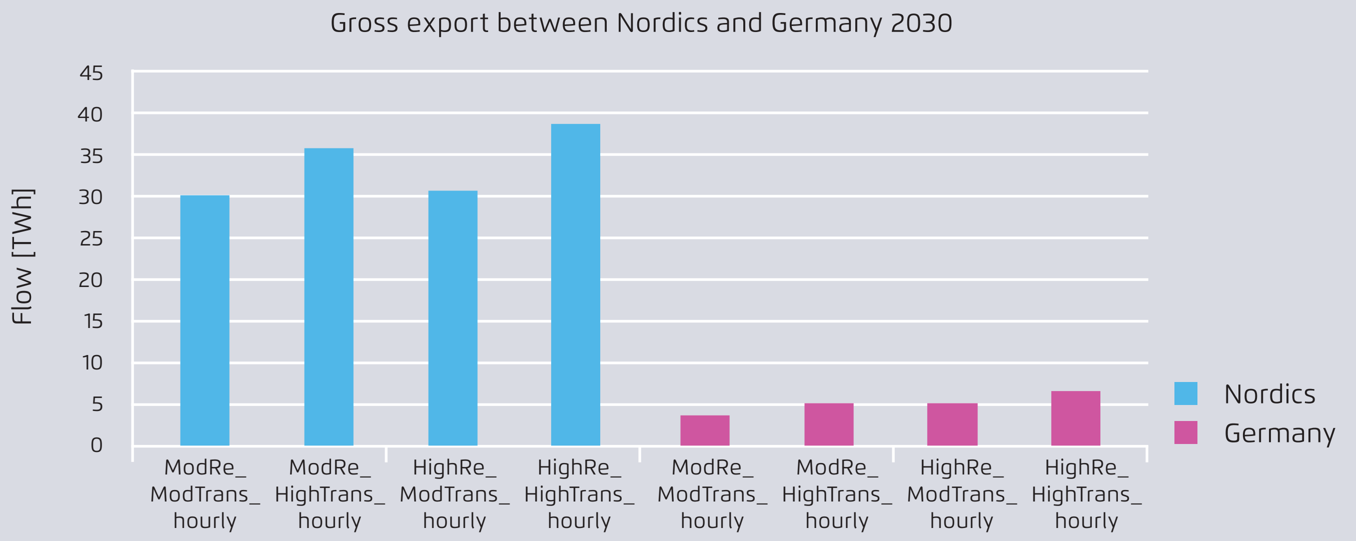
The electricity balance for the individual countries (Figure 21) illustrates one of the drivers for increased transmission capacity, namely the surplus of generation in the Nordic countries, which increases significantly in the High RE scenarios.

**Gross flows**

For the electricity exchange between the Nordic countries and Germany, the main flow direction runs from North to South, but even with the Nordic countries' high net export potential in the High RE scenarios, up to 5 TWh will be flowing from Germany to the Nordic countries (Figure 22).

Gross export between the Nordic countries and Germany in each of the four scenarios. Electricity flows to other neighbouring countries are not included.

Figure 22




Own calculation

## 4.7 Value of additional transmission capacity

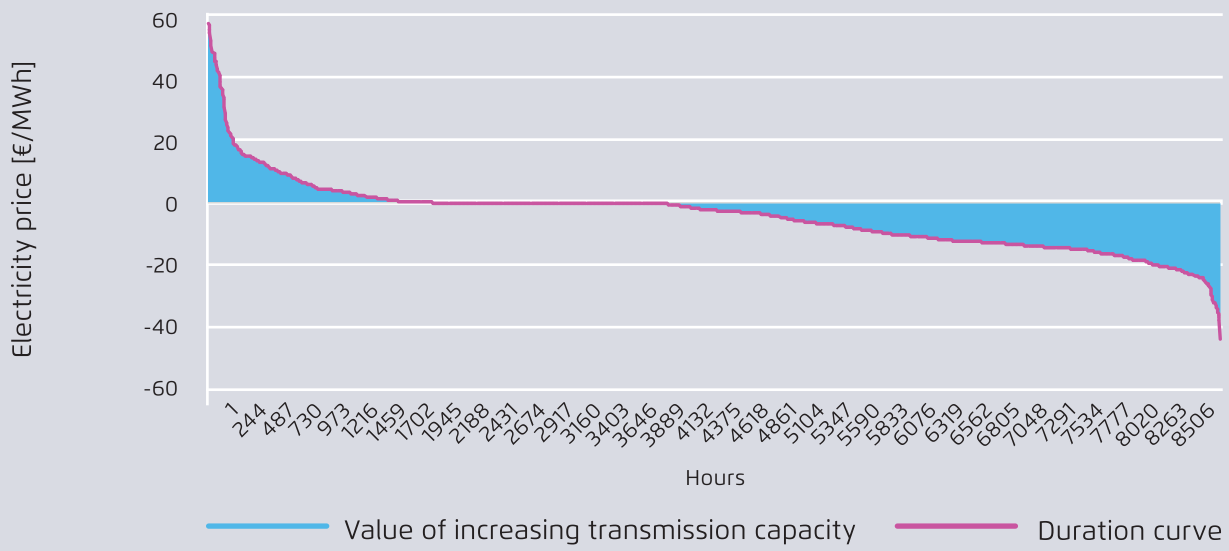
Our model simulation of hourly dispatch by generators determines all flows between regions. The value of having an additional Megawatt (MW) of transmission capacity is also calculated.[15] This value is equal to the price spread between two regions. Taking the total value over a year, the marginal value of adding 1 additional MW transmission capacity to a specific transmission line can be estimated. This principle is illustrated in Figure 23, which shows the duration curve for the price spread between two regions. The marginal value of transmission capacity is equal to the absolute sum of the price spread for all hours (red area). The red area above the x-axis is the value created by potential flow going from region 2 to region 1, while the red area below the x-axis is the value created by potential flow going from region 1 to region 2. During hours with equal prices, there is no value to be derived from increasing transmission capacity. The total congestion rent on a line between two regions is calculated by multiplying the price spread per hour between the two regions with the flow per hour between the two regions.

Even though the marginal value of additional transmission capacity is only valid for marginal changes in transmission capacity, it gives a good indication of where it would be beneficial to upgrade interconnections between regions. However, the values are not valid for large changes in transmission capacities, and could be affected by other changes in the transmission system. This means it is not possible to benefit from all marginal values at the same time.

The marginal value of adding transmission capacity is shown next to the transmission lines in Figure 24 to Figure 27 for each of the different scenarios. In general, values are considerably higher in the High RE scenarios due to the added amounts of RE in the Nordic countries and subsequent surplus electricity production. Furthermore, the addition of transmission capacity in the high transmission scenarios leads to slightly lower marginal values of new transmission capacity.

15 The model setup is restricted to showing only the marginal value of additional transmission capacity to existing lines, and therefore will not show the value of establishing transmission capacity between regions that were previously unconnected.

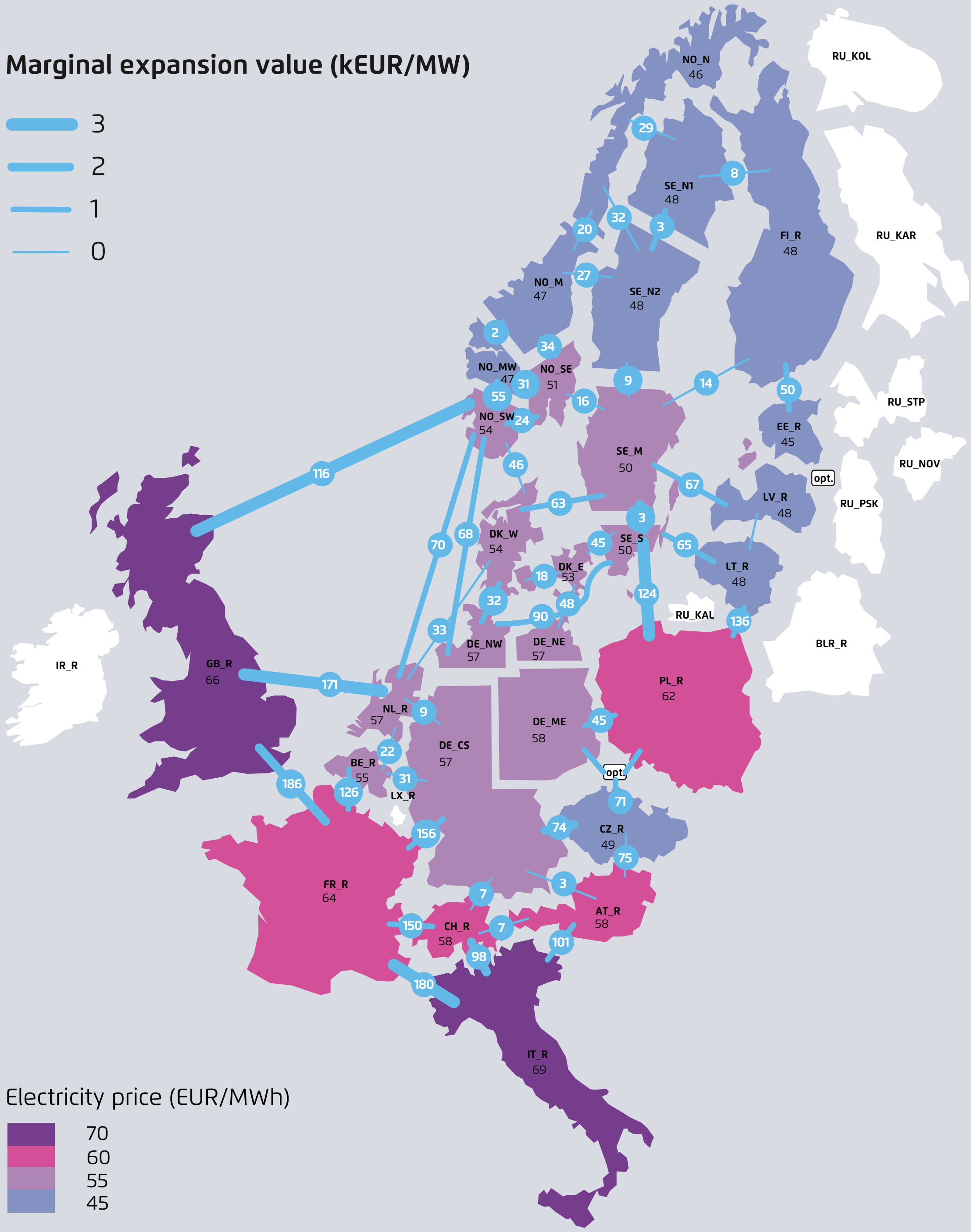
Illustration of the marginal value of transmission capacity, showing the price spread between two regions (region 1/region 2). Positive values indicate higher prices in region 1. Figure 23




Own calculation

Marginal values of transmission and average annual electricity prices in the ModRE_ModTrans scenario

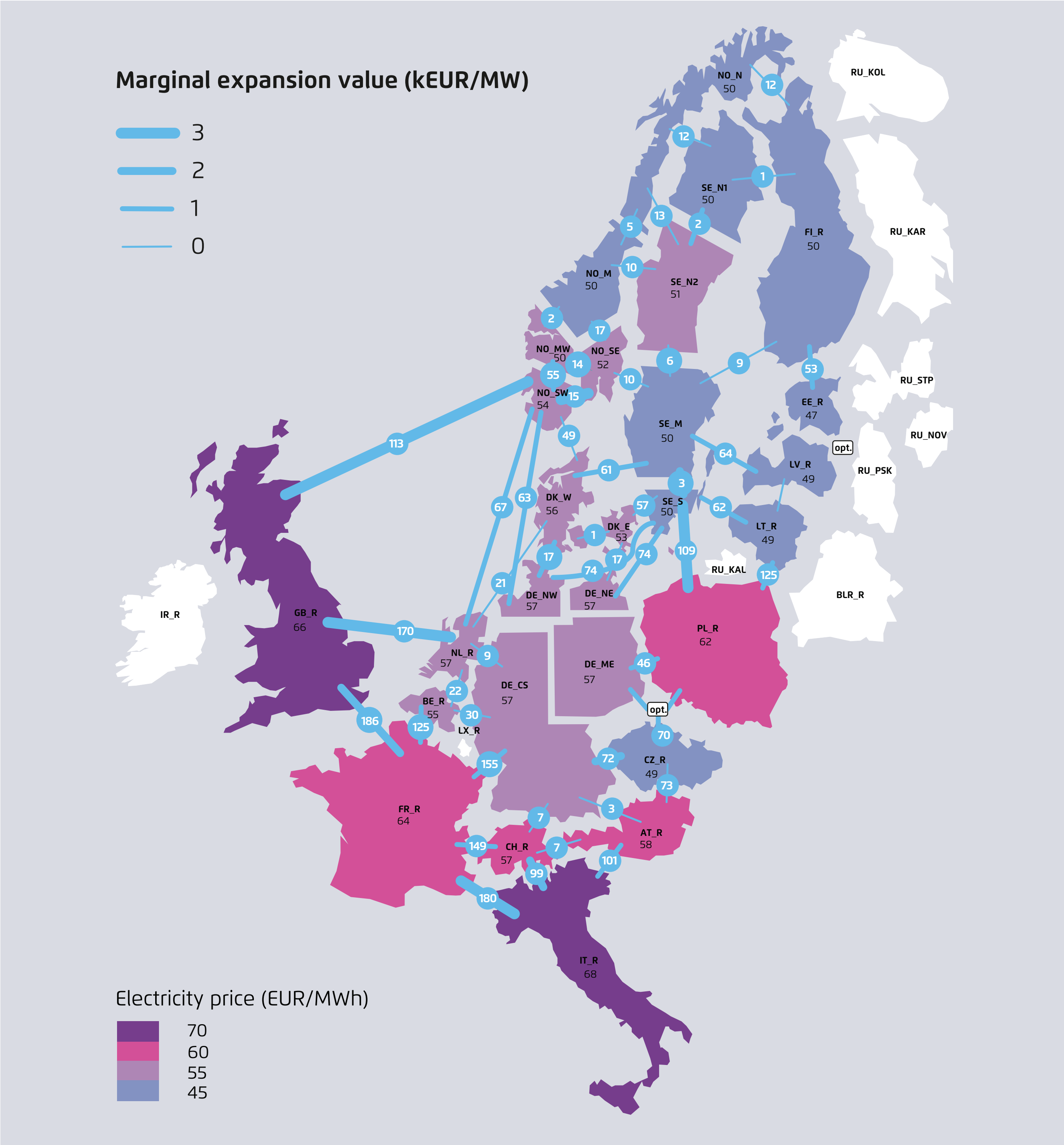
Figure 24




Own illustration

Marginal values of transmission and average annual electricity prices in the ModRE_HighTrans scenario

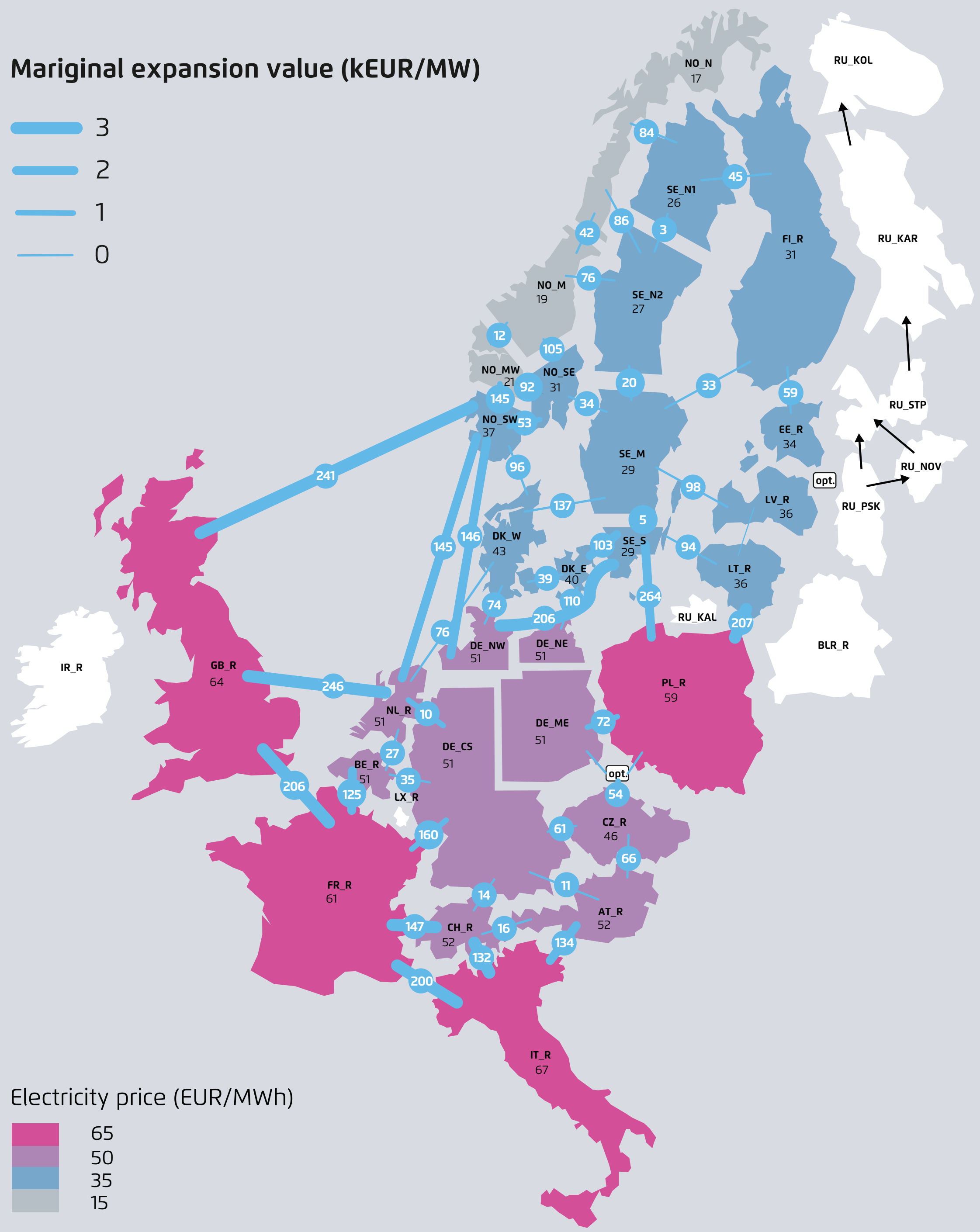
Figure 25




Own illustration

Marginal values of transmission and average annual electricity prices in the HighRE_ModTrans scenario

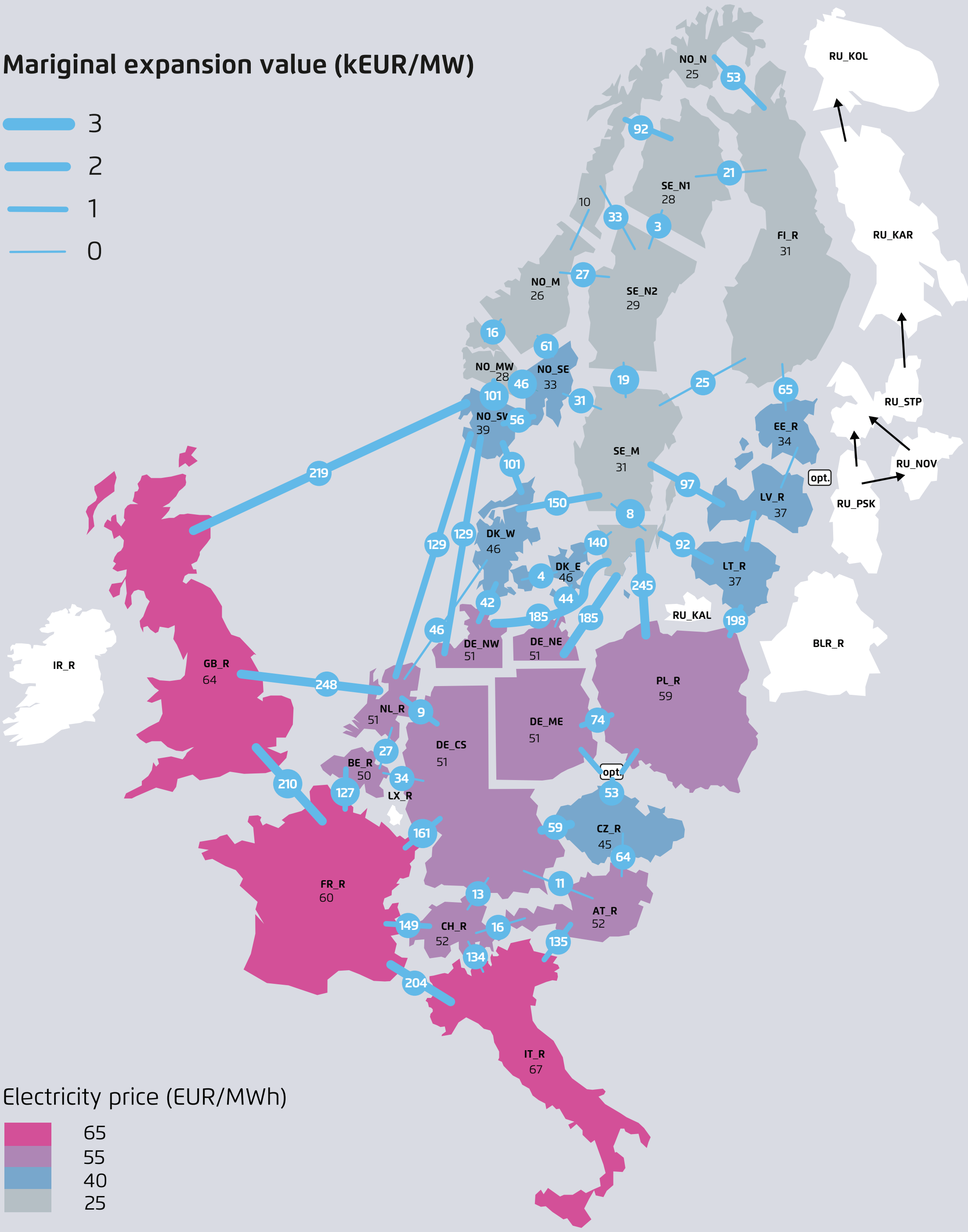
Figure 26




Own illustration

Marginal values of transmission and average annual electricity prices in the ModRE_HighTrans scenario

Figure 27




Own illustration

The transmission lines with increased capacity in the HighTrans scenarios are not the most beneficial lines. Although connecting southern Norway to continental Europe and the UK or connecting southern Sweden to continental Europe would be highly valuable, only three of the ten additional projects in the High Transmission scenario connect the Nordic countries to Germany (SE_S-DE_NE, DK_W-DE_NW and DK_E-DE_NE). Notably, two of those lines connect only Denmark and not Norway or Sweden to Germany (DK_W-DE_NW and DK_E-DE_NE). Thus, the marginal value of the lines with increased capacities in the High Transmission scenarios is limited compared to the investment cost (Table 10).

## 4.8 Operation of the system

**Modelling limitations**

The high level of variable renewable energy in the system leads to challenges in system operation. The simulations carried out in this project do not take into account any system operation requirements or restrictions, such as minimum online time for thermal power plants or minimum must-run capacity for certain dispatchable generators. However, all energy balances, including district heating supply, are fulfilled at all times, unless the specified electricity price ceiling of 3,000 EUR/MWh is reached. In this case, electricity demand is reduced.

Marginal value of transmission capacity for the transmission lines with higher capacity the High Transmission scenarios. The cost estimates are based on data from the TYNDP with an interest rate of 4 percent and 30 year lifetime. Operation and maintenance costs and costs of losses are not included.

Table 10

| Marginal value of transmission k€/MW | | | | | | | |
|---|---|---|---|---|---|---|---|
| **From** | **To** | **Capacity (Additional) MW** | **Cost k€/MW** | **ModRE ModTrans** | **ModRE HighTrans** | **HighRE ModTrans** | **HighRE HighTrans** |
| DK_W | DE_NW | 2,500 (500) | 20–24 | 32 | 17 | 74 | 42 |
| SE_S | DE_NE | 0 (700) | 17–33 | 90 | 74 | 206 | 185 |
| SE_N1 | FI_R | 1,300 (1,000) | 4–7 | 8 | 1 | 45 | 21 |
| NO_N | FI_R | 0 (500) | 35–81 | –* | 12 | –* | 53 |
| NO_N | SE_N2 | 275 (750) | 11–25 | 32 | 13 | 86 | 33 |
| DK_E | DE_NE | 600 (600) | 48–59 | 48 | 17 | 110 | 44 |
| SE_S | SE_M | 4,850 (700) | 14–22 | 3 | 3 | 5 | 8 |
| NO_M | NO_N | 600 (1,200) | 42–72 | 20 | 5 | 42 | 10 |
| DK_W | DK_E | 600 (600) | 38–46 | 18 | 1 | 39 | 4 |
| SE_M | SE_N2 | 8,000 (700) | 66–116 | 9 | 6 | 20 | 19 |

Own calculation; *Marginal value not shown if transmission line does not exist in the scenario.

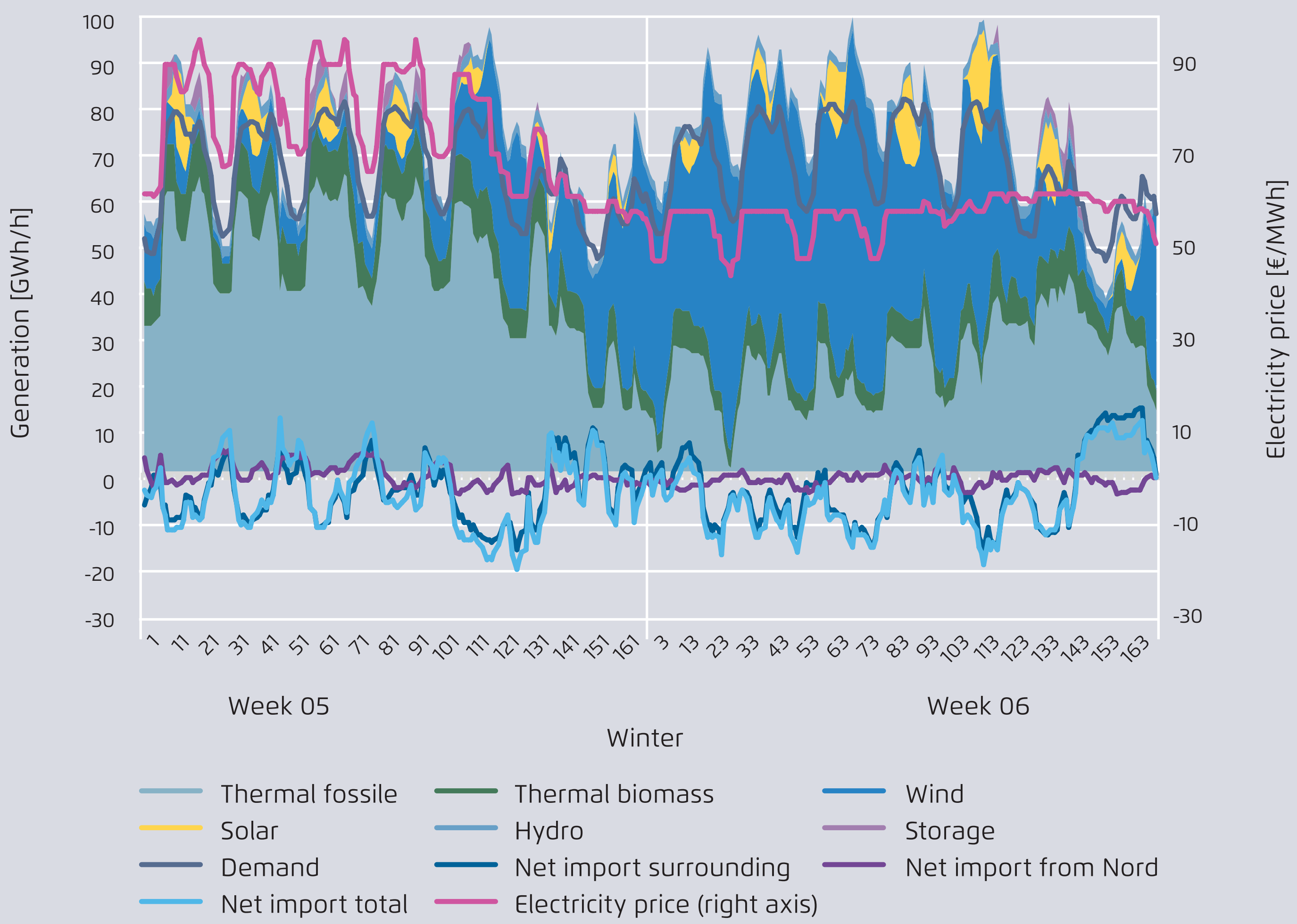
**System requirements**

Today, a number of requirements limit total system flexibility. These requirements are based on both physical limitations and operational experience. If the current system requirements are kept constant, especially those regarding must-run capacity of dispatchable generators, then the value of the additional RES-E will be reduced – despite the substantial amounts of variable RES-E added to the system – and the number of hours with excess electricity generation will increase compared to this project's calculations.

**The German power balance**

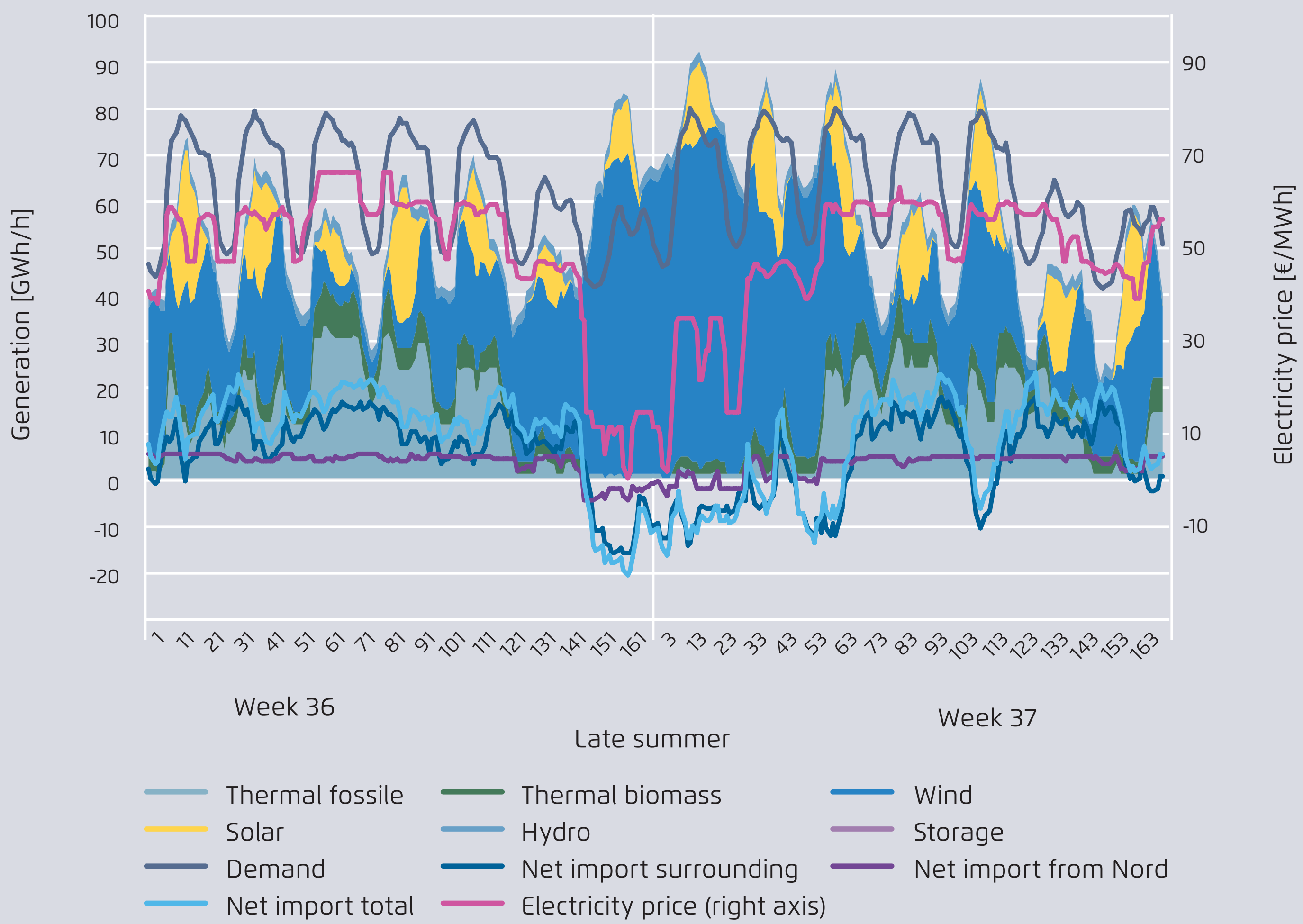
The challenges posed to system operation can be illustrated by considering the operation of the German power system for two weeks in winter and two weeks in late summer (Figure 28 and Figure 29). The blue and the yellow areas show the amount of variable electricity generation (wind and solar) in the German system. The grey line shows domestic electricity demand. The corresponding electricity price is shown by the pink line.

Depiction of the operation of the German power system over two weeks in winter under the ModRE_ModTrans scenario. The electricity price is shown on the right axis. Figure 28




Own illustration

Depiction of the operation of the German power system over two weeks in late summer under the ModRE_ModTrans scenario. The electricity price is shown on the right axis. Figure 29

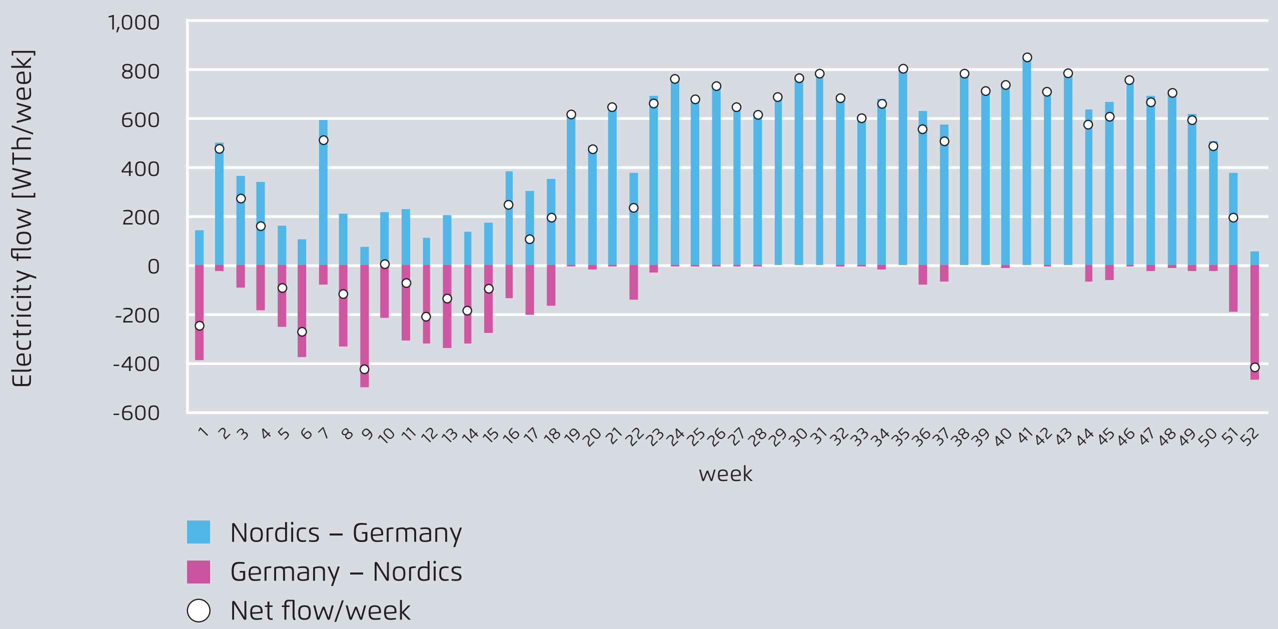



Own illustration

High levels of wind power generation do not necessarily result in very low electricity prices if the overall system load is relatively high (this is typically the case in winter). However, at week 5, with low generation from wind and solar power, electricity prices reach up to 95 EUR/MWh, while prices in week 6 (with higher wind penetration) reach a maximum of around 60 EUR/MWh. During late summer, where demand is lower compared to winter, especially in the Nordic countries, electricity prices are close to zero.

The effect of the balance in the Nordic system on electricity prices in Germany is also apparent in electricity exchange during the summer and winter. The transmission lines between the Nordic countries and Germany are mainly used for import to Germany during the summer due to low electricity demand in the Nordic countries. Unless German electricity prices become very low, exchange varies more during the winter, with both import and export occurring (Figure 30).

Gross electricity exchange between the Nordic countries and Germany. Negative flow indicates flow from Germany to the Nordic countries. Positive flow is from the Nordic countries to Germany. Figure 30




Own calculation

**The operational challenge**

The operation of the German power system described above illustrates the challenges facing system operation. In week 37, the generation level from dispatchable power plants is very low for a period of several days. If a must-run level for dispatchable generation[16] had been introduced here in the model, this would have led to increasing curtailment of variable RES-E, assuming everything else is unchanged. On the other hand, the value of transmission capacity would probably increase, as it delivers some of the required flexibility. In a study by Energy Brainpool for Agora Energiewende,[17] the current level of minimum generation from power plants for securing system stability is put at between 13 and 20 GW based on a study by FGH, a German research association for the electrical power industry.[18] The simulations carried out in this project have a significant number of hours with generation levels from thermal power plants below 20 GW (Table 11). However, if the required minimum generation from thermal power plants is reduced to 5 GW, only 600–1,200 hours per year fall below this limit. If a minimum level of 5 GW had to be maintained and balanced within the German system by curtailing variable RES-E, this would lead to a curtailment below 1 percent in all scenarios. However, a minimum generation level of 20 GW would lead to a curtailment of 10 - 18 percent. This illustrates the increasing challenge of flexibility when increasing variable RES-E within a system. This implies a need to reduce the minimum level of thermal generation by finding other resources to provide system stability services. At the same time, requirements

16 Minimum generation level in terms of operating thermal capacity (GW) at all times.

17 *Negative Strompreise: Ursachen und Wirkungen, Energy Brainpool for Agora Energiewende, June 2014.*

18 *Studie zur Ermittlung der technischen Mindesterzeugung des konventionellen Kraftwerksparks zur Gewährleistung der Systemstabilität in den deutschen Übertragungsnetzen bei hoher Einspeisung aus erneuerbaren Energien*, Forschungsgemeinschaft für elektrische Anlagen und Stromwirtschaft e. V., Consentec GmbH; Institut für Elektrische Anlagen und Stromwirtschaft, 2012

Number of hours with a level of thermal generation below a certain limit in the German power system. Thermal generation includes all thermal power plants, including smaller distributed generators. In addition to thermal generation, approximately 2.5 GW of hydro and geothermal power is operating at all times.

Table 11

| | Below 5 GW | Below 20 GW |
|---|---|---|
| ModRE_ModTrans | 604 | 3,482 |
| ModRE_HighTrans | 610 | 3,522 |
| HighRE_ModTrans | 1,140 | 4,662 |
| HighRE_HighTrans | 1,177 | 4,694 |

Own calculation

for system services could increase – for example, to absorb sudden changes in the level of variable generation from RES-E.

Other reasons for the operation of thermal power plants at times with low electricity prices and high generation from variable RE can be unit commitment issues, such as minimum downtime of power plants and ramping constraints. These issues were not analysed in this study.

# 5 Effects on system costs

**Socio-economic benefits**

Increased investment in transmission and RES-E affects the endogenous investments and system dispatch calculated by the model. Thus, they also affect the total cost of electricity supply in the system.

In the following, the total direct costs[19] of the HighTrans scenarios are compared to the ModTrans scenarios. Operation and Maintenance (O&M) costs in the existing grid are assumed to be unchanged in all scenarios and are therefore excluded from our calculations.

The direct costs included are investment, operation and maintenance costs, fuel and $CO_2$ costs. The value of $CO_2$ emissions is set equal to the $CO_2$ price based on IEAs New Policy Scenario from the World Energy Outlook 2013.[20] Furthermore, differences in the scenarios regarding the levels of hydro generation and the amount of non-served energy (due to reaching the price ceiling of €3,000/MWh) are included.

The model has higher degrees of freedom in the HighTrans scenarios and it is therefore to be expected that the total costs of electricity supply will be lower in these scenarios. This cost decrease is the calculated benefit of increased transmission capacity.

The cost of the additional transmission lines in the HighTrans scenarios is not included in the benefit calculations, but by comparing the benefits with the investment cost of the HighTrans package the cost benefit of the whole transmission package is analysed. In section 5.7 it was shown that the marginal value of increasing some transmission lines was clearly higher than their costs. However, in this section the costs and benefits of the total package are analysed. The total package covers both more and less beneficial transmission lines.

The benefits for total system costs do not cover all possible aspects of increased value from increased transmission capacity. Factors that can influence and are likely to increase the value of increased transmission capacity are the sharing of balancing reserves across regions, increased (or cheaper means of securing) security of supply as well as better options for coping with varying RES-E generation from year to year. The latter is especially important for hydropower-dominated countries such as Norway, where the inflow to hydropower plants can vary significantly from year to year. The effect of these variations was not analysed in detail in this study.

**Hydropower**

The hourly simulations are based on water values used for deciding the weekly amount of hydropower production (see section 4.2). Therefore, the annual amount of hydropower production can differ slightly from both the aggregated model runs and from other scenarios. The changes in the total level of hydropower production are taken into account in the socio-economic calculations. Therefore, using less hydropower will result in economic savings (as an isolated effect), while using more hydropower will result in higher spending.

**Moderate RE**

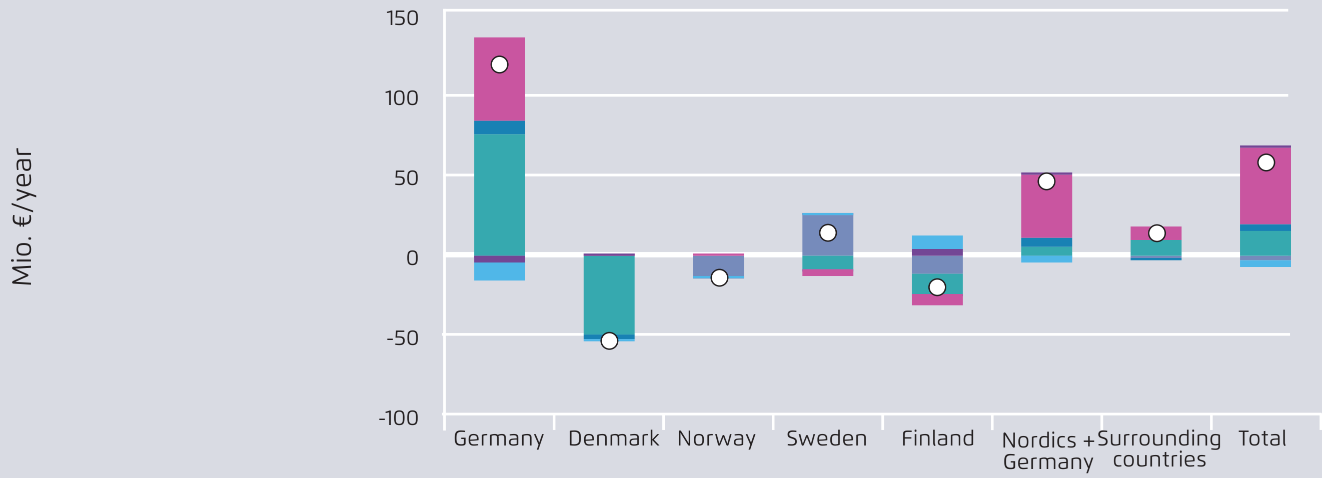
The ModRE_HighTrans scenario shows a total economic benefit of approximately €60 million/year, of which roughly €45 million/year reflects benefits within the Nordic countries and Germany. The major contribution is from $CO_2$ savings, but reductions in fuel costs also contribute to overall benefits.

The benefit calculated is considerably lower than the minimum annual cost of establishing the added transmission capacities, which has been estimated at €175-378 million/year at an interest rate of four percent and a lifetime

19 Direct costs do not include distortion losses or benefits caused by distributional effects on the different stakeholders or possible effects on the macro economy.

20 International Energy Agency (2013): *World Energy Outlook 2013*

Socio-economic effects of the ModRE_HighTrans scenario compared to the ModRE_ModTrans scenario. Benefits are shown as positive values, while additional costs are shown as negative values. Figure 31




| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Capital cost | -12 | -2 | 0 | 2 | 8 | -5 | 0 | -5 |
| Fixed O&M cost | -4 | 0 | 0 | 0 | 4 | 0 | 0 | 0 |
| $CO_2$-cost | 51 | 0 | 0 | -4 | -8 | 40 | 8 | 48 |
| Variable cost | 9 | -2 | 0 | -1 | 0 | 6 | -2 | 4 |
| Fuel cost | 75 | -50 | 0 | -9 | -12 | 5 | 10 | 15 |
| Water value | 0 | 0 | -13 | 24 | -12 | -1 | -2 | -3 |
| Value of not supplied electrity | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total | 119 | -54 | -13 | 14 | -20 | 45 | 14 | 60 |

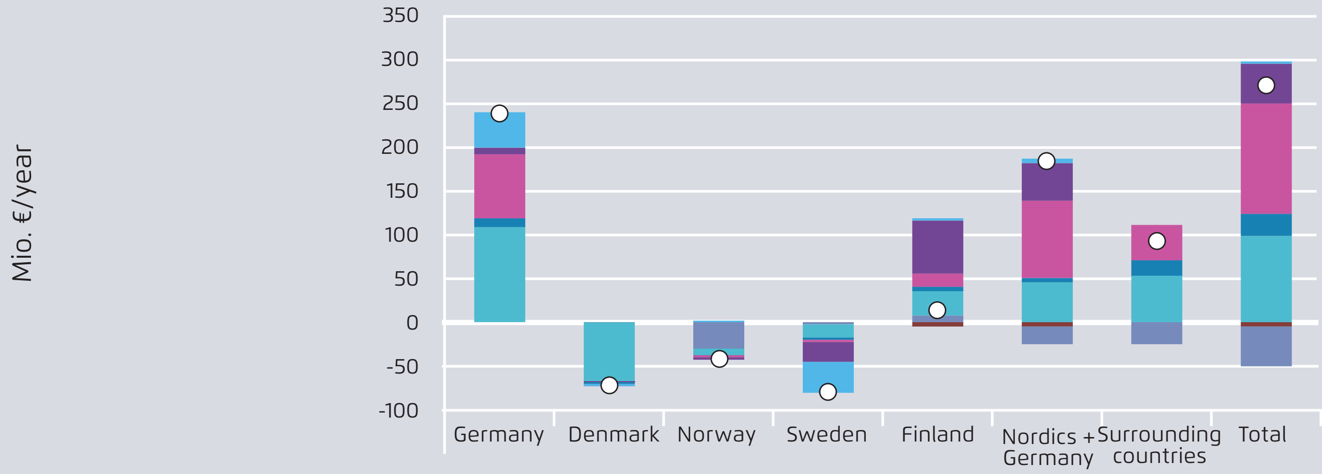
Own calculation

of 30 years (see section 3.3). This does not mean that added transmission capacity has no value to the system; rather, it shows that some of the investments in the package, and the package as a whole, have a negative cost/benefit result.

In the High RE scenarios, the benefits of adding transmission are considerably higher at around €250 million/year in total, of which €160 million/year are within the Nordic countries and Germany. The largest share is from reduced $CO_2$ emissions and fuel costs, but changes in decommissioning decisions for some power plants[21] (e.g. in Finland) also contribute to the overall savings. The total benefit of around €250 million/year is comparable to the annualised cost of investment in new transmission capacity, ranging from €208-348 million/year. In the High RE scenarios, the chosen transmission investments can therefore prove to be socioeconomically beneficial. Alternate choices concerning the transmission lines included in the High Transmission scenario (i.e. selecting lines with more beneficial ratios between investment cost and socio-economic benefit) would further increase overall socio-economic benefit.

21 Resulting in savings of fixed operation and maintenance cost.

Socio-economic effects of the HighRE_HighTrans scenario compared to the HighRE_ModTrans scenario. Benefits are shown as positive values, while additional costs are shown as negative values. Figure 32




| | Germany | Denmark | Norway | Sweden | Finland | Nordics + Germany | Surrounding countries | Total |
|---|---|---|---|---|---|---|---|---|
| Capital cost | 41 | -3 | 1 | -37 | 0 | 3 | 0 | 3 |
| Fixed O&M cost | 8 | 1 | -2 | -22 | 59 | 44 | 0 | 44 |
| $CO_2$-cost | 73 | 0 | -1 | -2 | 17 | 87 | 40 | 128 |
| Variable cost | 10 | -3 | -1 | -4 | 5 | 6 | 18 | 24 |
| Fuel cost | 109 | -67 | -8 | -14 | 26 | 46 | 53 | 100 |
| Water value | 0 | 0 | -29 | -2 | 9 | -22 | -24 | -46 |
| Value of not supplied electrity | 0 | 0 | 0 | 0 | -3 | -3 | 0 | -3 |
| Total | 242 | -72 | -40 | -81 | 113 | 161 | 88 | 250 |

Own calculation

# 6 Sensitivity analysis

In order to test the robustness of the results described in the previous sections, a sensitivity analysis was carried out concerning flexible demand and the level of nuclear power production. Sensitivity analyses on flexible demand were carried out for all scenarios, while the sensitivity analysis on the amount of nuclear power was based only on the HighRe_HighTrans scenario, which shows a considerable surplus in the Nordic countries.

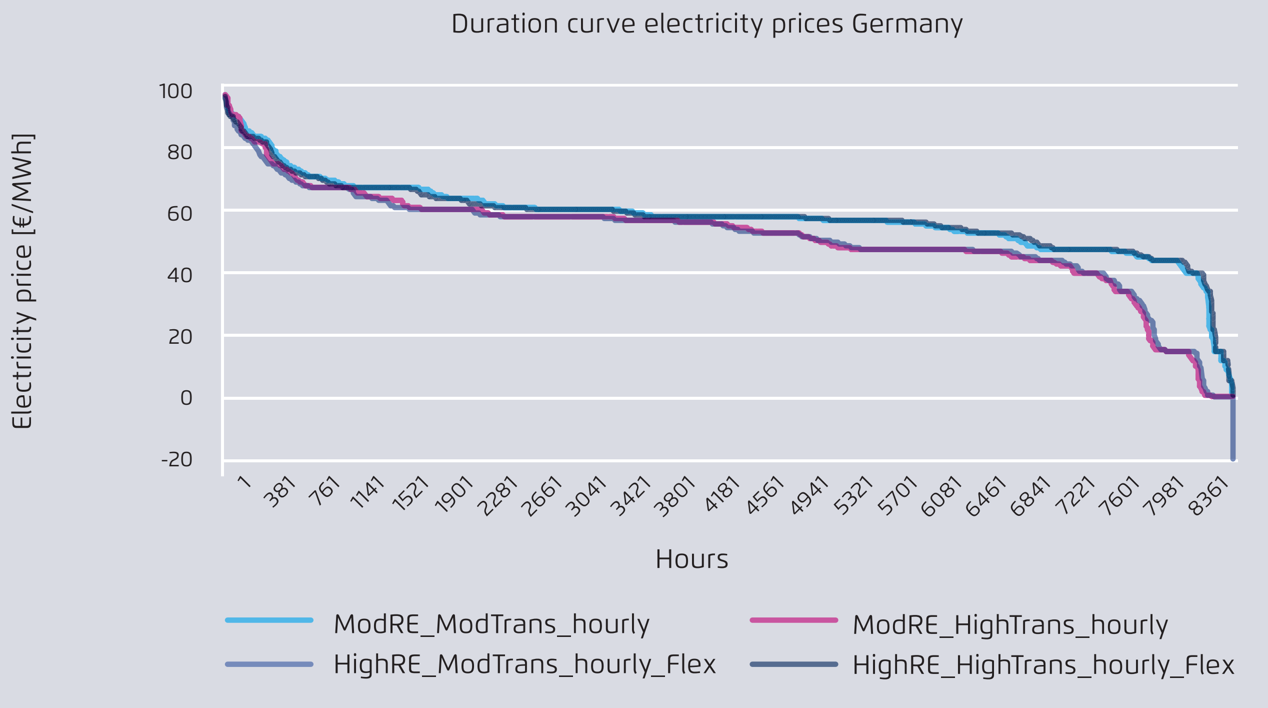
## 6.1 Flexible demand

### Level of flexible demand

Flexible demand is defined here as electricity demand response that has a price elastic demand, for example, such that electricity consumers shift demand from high price hours to low price hours (e.g. by moving some of the electricity demand from peak hours during the day to low price hours during night time). Our sensitivity analysis on flexible demand was carried out by running the hourly simulations again, with the added assumption that a certain share of demand, corresponding to 10 percent of the peak demand in each region, is flexible and can be shifted in time (load shifting). This number is a rough estimate intended to illustrate the effect flexible demand can have on the value of transmission capacity. The flexible demand is modelled as virtual electricity storage without associated losses or cost, i.e. the total demand is unaffected over a longer period, but load is shifted within the period without costs. Maximum electricity storage was set at 4 hours of load at 10 percent of peak demand.

Duration curves for electricity prices in Germany in the moderate transmission scenarios and the corresponding scenarios, including flexible demand

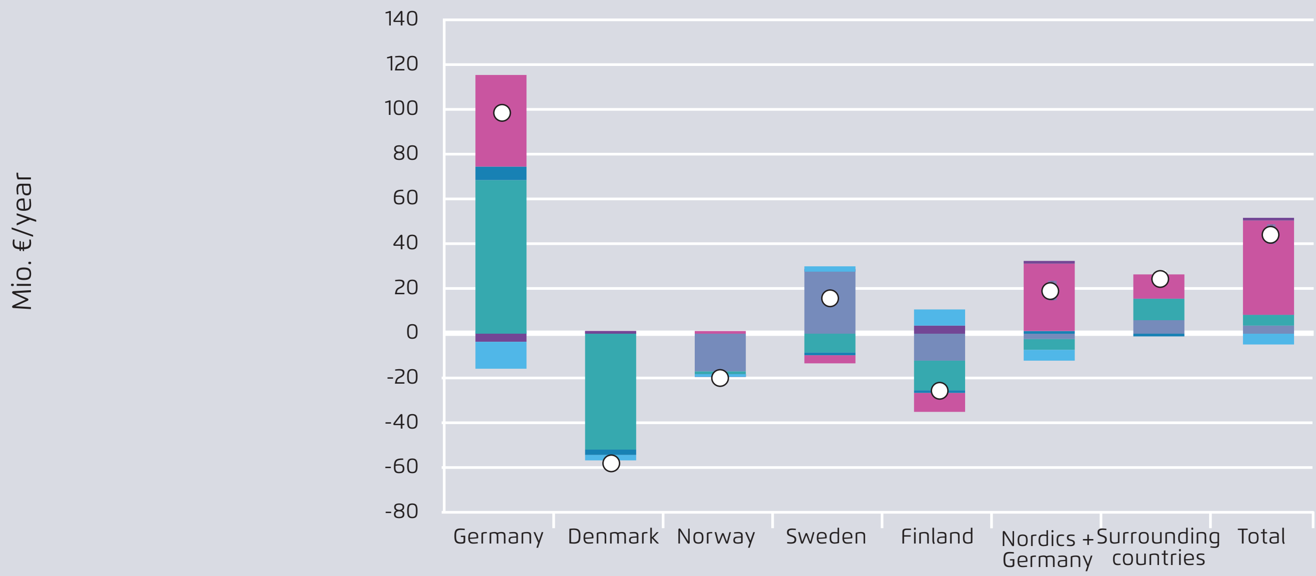
Figure 33




Own calculation

Socio-economic effects of the ModRE_HighTrans_Flex scenario compared to the ModRE_ModTrans_Flex scenario. Benefits are shown as positive values, while additional costs are shown as negative values. .

Figure 34




| | Germany | Denmark | Norway | Sweden | Finland | Nordics + Germany | Surrounding countries | Total |
|---|---|---|---|---|---|---|---|---|
| Capital cost | -12 | -2 | 0 | 2 | 8 | -5 | 0 | -5 |
| Fixed O&M cost | -4 | 0 | 0 | 0 | 4 | 0 | 0 | 0 |
| $CO_2$-cost | 42 | 0 | 0 | -4 | -9 | 31 | 12 | 42 |
| Variable cost | 7 | -3 | 0 | -1 | -1 | 2 | -1 | 0 |
| Fuel cost | 70 | -53 | 0 | -9 | -13 | -5 | 10 | 4 |
| Water value | 0 | 0 | -18 | 28 | -13 | -2 | 6 | 4 |
| Value of not supplied electrity | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total | 103 | -58 | -18 | 18 | -24 | 21 | 26 | 47 |

Own calculation

**Effects of flexible demand**

The simulation with flexible demand is carried out as an hourly simulation, without changing the investment decisions. Therefore, no savings in for example peak load power plants can be achieved; however, it is still possible to influence the dispatch of power plants. At the same time, introducing flexible demand in an otherwise unchanged system is expected to have the largest impact on the value of transmission.

Introducing flexible demand increases the value of electricity slightly during hours when prices are low (Figure 33). At the same time, high prices are reduced slightly. Overall, the effect on price duration curves for electricity prices is limited.

In the Moderate RE scenarios the total value of adding transmission is reduced by approximately €13 million/year. This is based on introducing flexible demand in both the ModRE_ModTrans and the ModRE_HighTrans scenarios (Figure 34). The reduced benefit of higher transmission is mainly due to reduced savings from fuel costs and $CO_2$ costs. The effect is slightly less pronounced in the HighRE scenarios, in which the value of the additional transmission is reduced by approximately €6 million overall.

When looking at the value of flexible demand alone, it is, than that of a scenario without flexible demand, the value is considerably higher. In the ModRE_ModTrans scenario, initial calculations show a value of around €200 million/year. This calculation does not include the cost of enabling the flexible demand.

## 6.2 Nuclear power production in Sweden

**Model setup**

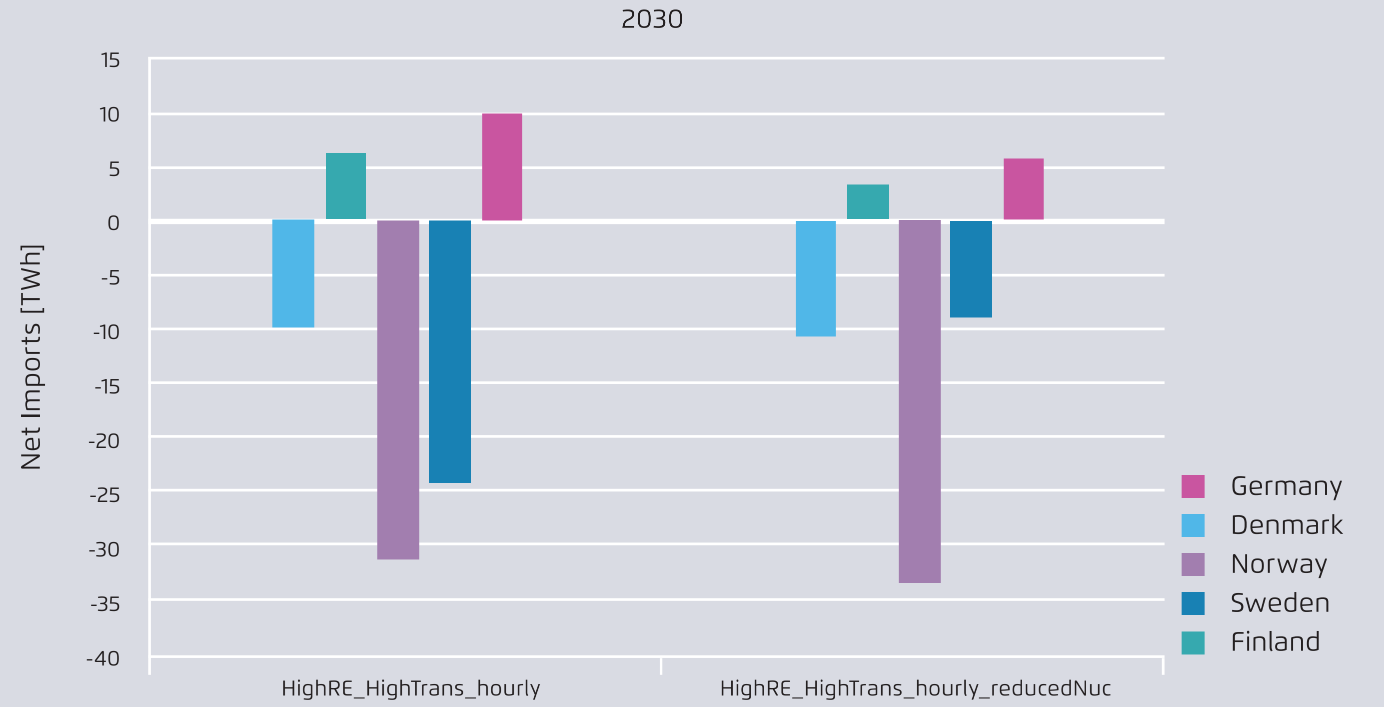
The sensitivity analysis on nuclear power production in Sweden is based on the HighRE_HighTrans scenario. The reason for this choice is that the level of generation from RES-E and nuclear is very high in this scenario compared to possible exports. The scenario with high levels of transmission was chosen as it seems to be the most viable when selecting a high level of RES-E. Nuclear power capacity in Sweden has been reduced from 7.9 GW to 5.0 GW by 2030.

Changes in electricity generation by fuel in the sensitivity analysis with lower nuclear capacity in Sweden compared to the HighRE_HighTrans scenario. Changes in RE generation within the Nordic countries and Germany are due to changes in the location of RE capacity, and for biomass due to the modelling setup, which means generation levels in the hourly simulations may differ slightly (see section 4.2). Table 12

| | Nordic countries | Germany | Surrounding countries | Total |
|---|---|---|---|---|
| Nuclear | -17.2 | 0.0 | 3.0 | -14.1 |
| Coal | 0.8 | 0.9 | 4.2 | 5.9 |
| Lignite | 0.0 | 2.2 | 0.5 | 2.7 |
| Other | 1.0 | 0.0 | 0.0 | 1.1 |
| MSW | 0.2 | 0.0 | 0.0 | 0.2 |
| Natural gas | 0.6 | 0.7 | 0.4 | 1.8 |
| Biogas | 0.1 | -0.3 | 0.1 | -0.1 |
| Biomass | 1.2 | 0.2 | -0.4 | 1.1 |
| Hydro | 0.8 | 0.0 | -2.2 | -1.4 |
| Wind | -0.2 | 0.0 | 0.0 | -0.2 |
| Solar | 0.0 | 0.0 | 0.0 | 0.0 |
| **Total** | **-12.64** | **3.74** | **5.63** | **-3.27** |

Own calculation

Net imports to the Nordic countries and Germany. Negative values show net exports. Figure 35




Own calculation

The RES-E requirements for all countries are kept constant. The scenario is therefore a setup in which the total surplus in the Nordic countries is reduced. The model allowed for investment in other generation capacities within the core countries.

### Investments and generation

The effect of reduced nuclear capacity on generation investment is limited. In Sweden, however, the thermal generation capacity for other fuels is around 1.2 GW higher than in the HighRE_HighTrans scenario, mainly due to reduced decommissioning of light oil- and coal-fired power plants. Apart from this, the main change in generator capacity is higher investment of around 1.3 GW in natural gas-fired peak load plants in Germany.

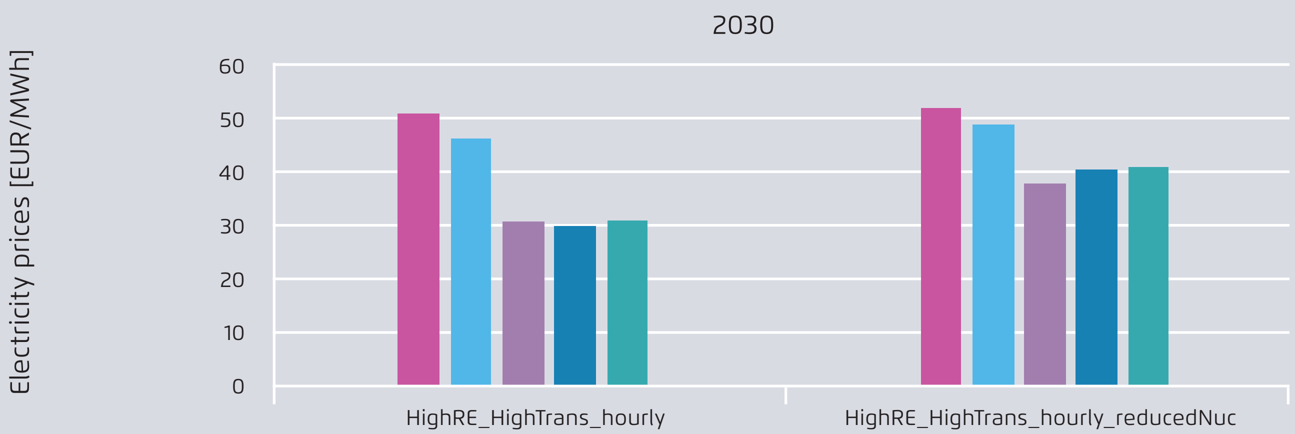
The reduced nuclear capacity in Sweden leads to a reduction in power generation of approximately 17.5 TWh. The missing generation is mainly replaced by additional generation based on coal, lignite and natural gas outside of Sweden (Table 12).

### Electricity prices and flow

The reduction in total electricity generation in Sweden results in reduced exports from Sweden, while both Finland and Germany reduce imports (Figure 35). The reduced generation from nuclear in Sweden also leads to higher electricity prices (short run marginal costs for electricity generation) in the Nordic countries in general, with the result of a smaller deviation from German prices (Figure 36). This is also an indication that the value of electricity trading is reduced. However, the higher prices will also lead to better economy for the RES-E generation in the Nordic countries.

Annual average electricity prices in the sensitivity analysis with lower nuclear capacity in Sweden and the main scenarios

Figure 36




| | HighRE_HighTrans_hourly | HighRE_HighTrans_hourly_reducedNuc |
|---|---|---|
| Germany | 51 | 51 |
| Denmark | 46 | 49 |
| Norway | 30 | 37 |
| Sweden | 30 | 40 |
| Finland | 31 | 41 |

Own calculation

**Marginal value of transmission**

The reduced price spread between the Nordic countries and Germany affects the marginal value of transmission capacity (Table 13). The value of connecting southern Sweden to Germany is reduced very sharply due to the reduction in surplus production in Sweden. At the same time, the value of connecting northern Norway to Finland and northern Norway to northern Sweden increases. The reason is that electricity prices in northern Norway are less affected by decreased nuclear production compared to prices in Sweden and Finland, leading to an increased price spread, and thus to an increased value of transmission.

The internal system in Sweden is to some extent affected by the reduced nuclear capacity in central Sweden, as a large share of demand (around 63 percent) comes from this area. The reduced nuclear capacity means that a larger share of electricity will have to be imported to the region. However, production within the region still covers 70 percent of nominal annual demand in the sensitivity analysis on an annual basis. This number is 87 percent in the HighRE_HighTrans scenario. This results in a minor increase in the marginal value of transmission capacity from northern to central Sweden. The number of hours of congestion on the transmission between northern and central Sweden is still very low at less than 50 hours/year. No detailed calculations were carried out concerning the effect on system operations in terms of system stability.

Marginal value of transmission capacity for the transmission lines with higher capacity the High Transmission scenarios. The cost estimates are based on data from the TYNDP with an interest rate of 4 percent and 30 year lifetime. Operation and maintenance costs and costs of losses are not included.

Table 13

| Marginal value of transmission k€/MW | | | | | |
|---|---|---|---|---|---|
| **From** | **To** | **Capacity (Additional) MW** | **Cost k€/MW** | **HighRE HighTrans** | **HighRE HighTrans reduced Nuclear** |
| DK_W | DE_NW | 2,500 (500) | 20–42 | 42 | 28 |
| SE_S | DE_NE | 0 (700) | 17–33 | 185 | 118 |
| SE_N1 | FI_R | 1,300 (1,000) | 4–7 | 21 | 18 |
| NO_N | FI_R | 0 (500) | 35–81 | 53 | 73 |
| NO_N | SE_N2 | 275 (750) | 11–25 | 33 | 57 |
| DK_E | DE_NE | 600 (600) | 48–59 | 44 | 30 |
| SE_S | SE_M | 4,850 (700) | 14–22 | 8 | 4 |
| NO_M | NO_N | 600 (1,200) | 42–72 | 10 | 14 |
| DK_W | DK_E | 600 (600) | 38–46 | 4 | 3 |
| SE_M | SE_N2 | 8,000 (700) | 66–116 | 19 | 24 |

Own calculation; *Marginal value not shown if transmission line does not exist in the scenario.

# Economic and Climate Effects of Increased Integration of the Nordic and German Electricity Systems

## Distributional Effects of System Integration and Qualitative Discussion of Implications for Stakeholders – Work Package 2

**WRITTEN BY**

Study developed within the frame of the project "Economic and climate effects of increased integra-tion of the Nordic and German electricity systems", carried out as "Work Package 2" by DIW Berlin, supported by Agora Energiewende.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DIW BERLIN

# Executive Summary of Work Package 2

Integration of the Nordic and German electricity systems supports European policy goals in the electricity sector, i.e. the internal energy market, by contributing to low carbon transformation and increasing security of supply.

Additional submarine transmission cables will strengthen the integration of the Nordic and German electricity systems. Trade flow will increase in **both directions**; under largely stable conventional capacity and with high renewable deployment in the Nordic region, most of the cross-border transmission **capacity** will be required **for exports** to Germany.

Integration will trigger **price convergence** between the Nordic region and Germany, resulting in **distributional effects**; prices **increase in the Nordic region** and Germany will see a small decline. Average price spreads will decrease from 10 to 7 EUR/MWh for the moderate and from 26 to 20 EUR/MWh for the high renewable scenario.

System integration affects generation investment and wholesale electricity prices, redistributing **costs and benefits between countries**. In terms of total system benefits within the model framework, **most countries will gain rents** under all scenarios. **Denmark** has a special role as a transit country. The specific distribution depends on the scenario assumptions. Generally, asymmetric allocation of costs and benefits could hamper the regional development of the electricity system.

In addition, **internal network enforcement** is required for **hinterland integration** but may also suit other needs, such as the **integration of renewables** or **security of supply**. Moreover, the costs for interconnectors and hinterland integration will have to be prudently distributed. In this respect, **the potential lack of national strategic incentives** could be compensated by **cross-border cost allocation** schemes on a multilateral level.

Price convergence creates winners and losers among **consumers and producers**. Effects will be **several times higher** than for national redistribution. In Norway, Sweden and Finland, about **300–400 million EUR/year** will be shifted within each country from consumers to producers with additional integration. In the High Renewable scenario, levels in **Norway** will increase to **900 million EUR/year** while they remain equal in Sweden and decrease in Finland. Compared to the distributional effects of benefits of increased integration among countries, the distributional effects will be substantially higher across stakeholder groups within an individual country.

**Energy-intensive industry** in the Nordic region historically benefits from low electricity prices. Wholesale electricity prices in the Nordic region will **decrease** with **renewable deployment** and weak interconnection and **increase** with **integration**. Current price composition supports energy-intensive industry: firms pay a **reduced energy price** and **low transmission tariffs**, thus covering only a small share of system costs. These firms are mostly **exempt** from **other charges**, which are passed on to other consumers.

# 1 Introduction

**The Nordic region and Germany:**
**An area that could strongly benefit from additional system integration**

The European electricity sector, on its way to decarbonisation, is undergoing a major transformation towards a single Europe-wide electricity market with low carbon electricity generation. Stakeholders at the European, regional and national levels collaborate in the planning and investment into renewable and conventional supply as well as electricity networks and by collectively defining new policies and regulations. Starting out from electricity systems with a strong national focus, cross-border transmission capacity has been historically underdeveloped. Also, national policies and geographic realities have lead to systems that differ with respect to their focus on specific technologies on the supply side as well as in their incentives for residential and industrial power consumption.

The North and Baltic Seas region, i.e. in this study Norway, Sweden, Finland, Denmark (the Nordic region) and Germany, is of particular interest in this transformation for the following two reasons: 1) today, few submarine cables link the Nordic and central European markets; and 2) stronger integration would link two systems with very different supply portfolios – increasing levels of wind power around the North and Baltic Seas with hydro-power in Scandinavia. Cross-border integration can provide benefits but would also have implications for regional market results and distributive effects in the respective countries.

**Quantitative scenario results:**
**Implications of renewable deployment and system integration**

The quantitative results in Work Package 1 ("Outlook for Generation and Trade in the Nordic and German Power System", Ea and DTU, 2015) of this study indicate system implications for two different renewable and integration scenarios for the Nordic region and Germany. The modelling results show that additional renewable deployment in the Nordic region will have a greater impact by decreasing wholesale electricity prices in the Nordic price zones than the price increase that will be induced by integration with more transmission capacity. This finding reflects supply and demand situations, especially in Norway and Sweden, where strong renewable deployment of wind power has a high potential to decrease electricity prices significantly, given the presence of largely stable conventional capacity. Additional interconnector capacity will enable increased exports to Germany.

Overall, cross-border integration is beneficial for system operation. Hours with high wind generation in Denmark and northern Germany will prompt electricity exports to the Nordic region, which will replace seasonal hydro-storage in Norway and Sweden. By contrast, the temporal shift in hydro-power generation will increase exports during other hours. This effect will decrease with higher renewable deployment in Norway and Sweden as additional shares of interconnection capacity are required for the export of electricity surpluses.

**Aim of this report:**
**Distributional effects and qualitative discussion of stakeholder implications**

This report, "Distributional Effects of System Integration and Qualitative Discussion of Implications for Stakeholders", constitutes the qualitative part (Work Package 2) of the study "Economic and climate effects of increased integration of the Nordic and German electricity systems". It builds on the modelling results of the quantitative analysis presented in Work Package 1.

The aim of this report is to conduct a detailed qualitative analysis of distributional effects at the national and stakeholder levels, as well as to engage in a qualitative discussion of implications for stakeholders.

Accordingly, this report addresses:

- price and distributional effects at the national and stakeholder levels in the electricity market (section 3),
- implications for residential and industrial electricity consumers (section 4),
- implications for national and regional network development (section 5) and
- market integration of cross-border transmission capacity (section 6).

To lay the foundation for our qualitative analysis, the following section 2 provides information on the development of the national electricity sectors in Germany and the Nordic region as well as their cross-border integration in the North and Baltic Seas region.

Section 3 begins with the central quantitative results of Work Package 1 and goes on to elaborate distributional implications. System integration is generally accompanied by price convergence and distributional effects. A lack of national strategic incentives could potentially hamper network investment and reduce cross-border market capacity, as indicated in numerous publications (e.g. Egerer et al., 2013; Moser et al., 2014). This report corroborates this view, because it observes a redistribution of rents as a consequence of additional integration between the Nordic region and Germany. An analysis of costs and benefits illustrates their asymmetric allocation at the country level. In addition, distributional effects between generators and power consumers in the entire Nordic region and Germany account for several times the calculated systems benefits, ranging between 0.8 and 1.1 billion EUR/year.

Section 4 describes, by country, the characteristics of residential power consumption and the composition of manufacturing branches in relation to employment and energy intensity. The aim is to highlight differences between countries and to illustrate the macroeconomic effects of changes in electricity prices.

Section 5 qualitatively reflects on the economics of interconnector investments, transmission tariffication and alternative financing in addition to cost-allocation schemes which could help to overcome distributional hindrances.

Section 6 discusses two additional aspects of system integration: the market integration of cross-border capacity in different sub-markets and the sensitivity of the quantitative results in relation to congestion management and regional electricity pricing.

# 2 National Electricity Sectors and Cross-Border Integration

## 2.1 European and national perspectives

At the European level, the Internal Energy Market (IEM) for electricity combines national systems, which have specific historical power plant portfolios according to their respective geographical conditions as well as socio-political decisions and preferences. The Emissions Trading Scheme (EU-ETS) acts as a regulatory instrument on the European level to guide the low carbon transformation with decreasing annual certificate volumes. As of late, the EU-ETS has been unable to provide sufficient incentives to reduce emissions, given that certificate prices have ranged between 3 and 8 EUR/ton $CO_2$ over the past two years (EEX, 2015).

On the other hand, the initial levels from which the low carbon transformation begins, and the speeds and means available for carrying out the process, vary from country to country. The so-called 20-20-20 targets aim at achieving a 20 percent renewable energy supply by 2020 throughout Europe (Directive (EU) 2009/28/EC). To attain this international target, individual countries have been required to develop National Renewable Energy Action Plans (NREAP) detailing their own renewable energy targets. The method of implementation (i.e. the choice of instruments and renewable technologies to be applied) is left to the discretion of each country.

**Developments in the electricity sector from a national perspective**

The specific characteristics of national electricity sectors are determined by the geographic availability of hydro-power, coal and natural gas resources; by national preferences regarding nuclear power; and, in recent years, by national support for developing wind, solar and biomass technologies.

→ Germany and Denmark have a long history of fossil generation, mainly from hard coal, while Germany also has additional nuclear capacity. Compared with other countries, natural gas did not gain large shares in supply during the 1990s. However, both countries (first Denmark and later Germany) witnessed continuous growth in wind power capacity during the same period. In Germany, wind capacity is concentrated primarily in the north. As for Denmark, in 2014, wind energy alone contributed to 39.1 percent of Danish electricity consumption (Klima-, Energi- og Bygningsministeriet, 2015a), setting a new record. The renewable share in total electricity supply amounted to 46.7 percent in Denmark in 2013, comprised predominantly of wind energy and bio-energy (Energistyrelsen, 2015). In Germany, the share of renewable electricity – primarily wind power complemented by biomass energy and, increasingly, photovoltaics – has been on the rise, reaching 27.3 percent of domestic electricity consumption in 2014 (Agora, 2015). Also, both countries are faced with the challenge of creating system flexibility as shares of fluctuating renewable generation, mainly from wind power, are on the rise.

→ Sweden and Finland are primarily supplied by a combination of hydro-power (from run-of-river and seasonal reservoirs) and nuclear power. Norway relies almost exclusively on hydro-power, which has, given its large reservoirs, a more pronounced seasonal character compared with Sweden, where hydro-generation is based instead on cascading river systems. Flexibility is abundant, but poor hydrological years (i.e. low annual precipitation) can result in scarce supply that can in turn result in very high electricity prices. In the coming decades, wind power will be added to this mix, posing challenges for balancing supply and demand.

Regarding conventional generation, the current trend – i.e. excess capacity in thermal generation and low electricity prices – may potentially force hard coal and gas fired power plants to decrease capacity or shut down, which could raise issues concerning firm capacity in coming decades. Also, nuclear power will be phased out in Germany by 2022, and lignite and hard coal capacities may be reduced to fulfil stricter national emissions targets for 2020 and beyond. In Sweden, the decision on nuclear power is still pending, but the high cost of retrofitting existing power plants could result in some plant closings.

The low carbon transformation in Germany and Denmark has already had a major impact on the spot market. Electricity prices have decreased as a result of excess capacity during hours of high renewable generation. Additional integration between Germany and Denmark with Norway and Sweden is one option under consideration, the idea being, on the one hand, to balance fluctuating renewable generation from wind power in Denmark and northern Germany over a larger region and, on the other, to increase access to additional short-term flexibility and the abundant firm capacity of Norwegian and Swedish hydro-power.

There is a general trend within the IEM towards stronger integration of national electricity markets. In addition to national developments on the supply side, changes in national market design impact neighbouring markets – an effect which increases with stronger integration. Examples include regional pricing by means of market coupling, balancing markets, and reserve markets (see section 6 for a brief discussion). However, one prerequisite for market integration is investment in additional interconnector capacity between the Nordic region and Germany.

## 2.2 Physical integration of national electricity markets

**Physical transmission systems between the Nordic region and continental Europe**

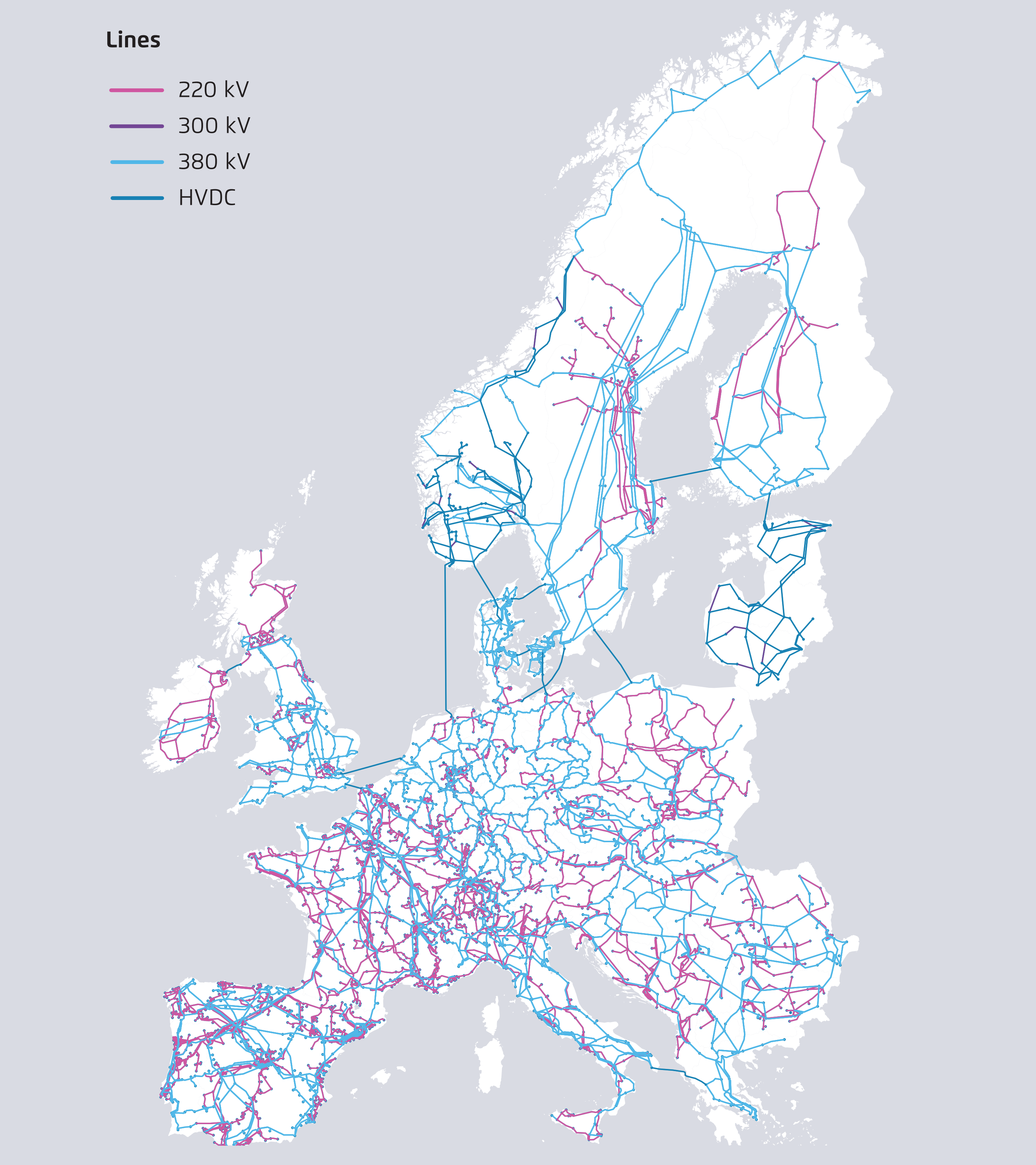
In Europe, high-voltage transmission networks for the transport of electricity over long distances have evolved gradually, and exhibit a strong national focus. In the past, each national utility used to jointly optimise investments in conventional power plants close to load centres and the transmission grid, thereby linking generation to load; national utilities would also often cooperate with one another toward the same end. Due to concerns about security of supply, these utilities would also integrate their national systems with those of neighbouring countries, although with limited cross-border transmission capacity. In some countries, the regional availability of hydro-power influenced the development of the network (e.g. along a north-south corridor in Sweden). Following geographic borders (the North and Baltic Seas), several wide-reaching synchronous grids evolved, for instance, the regional grids of continental Europe, the Nordic region, the United Kingdom, Ireland and the Baltic states. Today, high voltage direct current (HVDC) submarine cables provide limited transmission capacity linking these regional grids (Figure 1). Compared to alternating current (AC) technology, direct current (DC) technology is better suited for the high capacitance of submarine cables. HVDC transmission lines are also capable of connecting two unsynchronised alternating current networks.

The Nordic region and continental Europe have a historically weak physical interconnection. Denmark-West (DK-W) is synchronous with the German transmission system and connected by two transmission lines. Both links have two circuits operating with 220 kV and 380 kV, respectively. Plans are in the works to build a second 380 kV line intended to strengthen the north-south connection (transit flows and wind integration).

Denmark-East (DK-E) is synchronous with the electricity system in southern Sweden. The North and Baltic Seas constitute a natural border between the unsynchronised systems of the Nordic region and continental Europe. The very first submarine cable connecting Denmark (Helsingør) to Sweden (Helsingborg) was put into operation one hundred years ago, in 1915. This 25 kV electricity cable had a length of 5.4 km (Klima-, Energi- og Bygningsministeriet, 2015b).

The first HVDC submarine cable, a 250 MW connection designed to connect the two unsynchronised AC systems in Denmark-West and Sweden, was put into operation in 1965. Interconnection capacity initially remained below 1000 MW, though two additional cables had been laid by 1993. After that, capacity slowly increased with the addition of more submarine cables. Altogether, up to the present, there have been seven additional 500-700 MW cables laid, responsible for interconnector capacity of approximately 5000 MW (Table 1).

European transmission network in 2012 | Figure 1




Own depiction based on ENTSO-E (2014f) and own research.

HVDC submarine cables linking Nordic and continental Europe — Table 1

| Interconnector | Start and end country | Capacity | Year |
|---|---|---|---|
| Kontiskan 1 | Sweden – Denmark West | 250 | 1965 |
| Skagerrak 1 / 2 | Norway – Denmark West | 500 | 1976 |
| Kontiskan 2 | Sweden – Denmark West | 300 | 1988 |
| Skagerrak 3 | Norway – Denmark West | 500 | 1993 |
| Baltic Cable | Sweden – Germany | 600 | 1994 |
| Kontek | Denmark East – Germany | 600 | 1995 |
| Swepol | Sweden – Poland | 600 | 2000 |
| Norned | Norway – Netherlands | 700 | 2008 |
| StoreBaelt | Denmark East and West | 600 | 2010 |
| Skagerrak 4 | Norway – Denmark West | 700 | 2014 |
| (AC network) | Denmark West – Germany | NTC ~1500 | |

ABB (2015)

The development of the North and Baltic Seas Grid is one priority of the "European energy infrastructures for 2020 and beyond", which proposes as a main objective the development of the offshore grid connection to Northern as well as Central Europe (European Commission, 2010a). The plan is to connect offshore and onshore wind capacity with consumption centres in Northern and Central Europe as well as with hydro-storage facilities in the Alpine region and the Nordic countries. This integration is important since it would enable continental Europe to accommodate large volumes of surplus electricity generated by wind and hydro-power in and around the Northern and Baltic Seas, while at the same time connecting major consumption centres in continental Europe with these new generation hubs and the abundant storage capacities of the northern and Alpine countries.

A number of different visions for extensive offshore grids have been put forth (see E3G and Imperial College London, 2014) that would join HVDC interconnectors to meshed elements with offshore wind integration. Most current projects, however, work mainly within the traditional scheme of point-to-point connections between two countries. Skagerrak 4 with 700 MW between Norway and Denmark began operating in late 2014, and was officially inaugurated in March 2015. The interconnectors scheduled for operation within the next ten years continue the steady increase in physical exchange capacity. The final investment decision on the Nord.LINK cable with 1400 MW between Norway and Germany was made in February 2015. Commercial operation is scheduled for 2020. A second interconnector with 1400 MW, the NSN Link between Norway and the United Kingdom, is in the final planning phase and may well be realised around 2020 as well (Statnett, 2015). In the Baltic Sea, current projects are set to provide additional capacity between Sweden and the Baltic states, meanwhile there is a general discussion on additional cables to begin in Germany and terminate in Denmark-East (Kriegers Flak, Kontek 2) and Sweden (Hansa PowerBridge).

The European electricity market is composed of bidding zones which, for the most part, follow national borders throughout continental Europe, though some countries in the Nordic system are comprised of several bidding zones. All point-to-point HVDC interconnectors link two different bidding zones. This allows for the inclusion of physical capacity as a trade constraint in the market dispatch. However, the converter stations connecting HVDC submarine cables to the meshed onshore networks are all located in coastal regions. Often the AC network requires additional enforcement for hinterland integration to load and generation centres. Otherwise the AC network can impose constraints that limit hourly usable interconnector capacity (see section 6).

**Transmission expansion plans on the national, regional and European levels**

Planning and investment in transmission systems remains within the national domain, given that 1) the cost of transmission networks are mostly paid by national transmission tariffs, 2) the development of new transmission projects are dependent on national regulators and national law and must also take into account land-use planning at the regional level; and 3) the first level of published network development plans concern the nation as a unit. Regulation (EU) 2009/72/EC states that annual plans must include all projects to be realised within the next three years and must indicate to market participants the main transmission infrastructure that needs to be built or upgraded within the next ten years.

- → Germany: The *Bundesbedarfsplan* includes 36 transmission projects (BGBL, 2013), with a focus on internal north-south enforcements; 16 projects are of cross-country relevance and/or are cross-border projects.
- → Denmark: The System Plan primarily involves cross-border projects, reflecting the geographic scope of Denmark as a transit hub; offshore wind integration projects are also involved (Energinet.dk, 2013).
- → Norway: The national grid development plan mostly describes the hinterland integration of planned offshore connectors to the United Kingdom and Germany via southern Norway, ongoing through 2023 (Statnett, 2014).
- → Sweden: *The perspektivplan 2025 – en utvecklingsplan för det svenska stamnätet* focuses on internal north-south network enforcement and interconnectors to the Baltic countries (Svenska Kraftnät, 2013).
- → Finland: Plans primarily involve internal network investment to connect new wind and nuclear capacity in addition to a third AC interconnector linking northern Sweden and Finland (Fingrid, 2013).

The trend toward European market integration and low carbon transformation indicate the importance of better cross-border integration. Regulation (EU) EC/714/2009 describes the supra-national rules of network planning that is conducted at both the regional and European levels. Regional Investment Plans for six regional groups are published on the ENTSO-E platform; the North Sea region and the Baltic Sea region represent two of these six regions (ENTSO-E, 2014c, ENTSO-E, 2014d). Compared to the national plans, these plans only include projects of regional importance. Due to a long history of cooperative network planning, there is an additional platform that exists in the Nordic region. The transmission system operators (TSOs) of Norway, Sweden, Finland, Denmark and Iceland develop the Nordic Grid Development Plan. Today, the Nordic Grid Development Plans are connected to the North Sea and Baltic Sea of ENTSO-E. The 2014 Nordic Grid Development Plan highlights four investment drivers in the region (Fingrid et al., 2014):

- → planned RES capacity and increasing consumption in the northern Nordic region,
- → north-south flows in Norway, Sweden and Finland,
- → increased capacity between the Nordic region and continental Europe and the United Kingdom, and

→ the Baltic states' north-south power transmission corridor between Northern and Central Europe.

At the European level the Ten-Year Network Development Plan (TYNDP) has to be prepared by ENTSO-E every two years. This schedule is driven by a need for consistency among national and regional plans, even though not all national and regional projects may be incorporated into the TYNDP.

# 3 Quantitative Model Analysis and Distributional Implications

## 3.1 Recap: Methodological approach and scenario assumptions of Work Package 1

The quantitative part of the project, Work Package 1 (Ea and DTU, 2015), applies an electricity market model to scenarios for the closer integration of electricity markets in the Nordic region and Germany in order to derive system and market results (i.e. results concerning investment, system costs, prices and trade flows). The model optimises the electricity system in two consecutive steps.

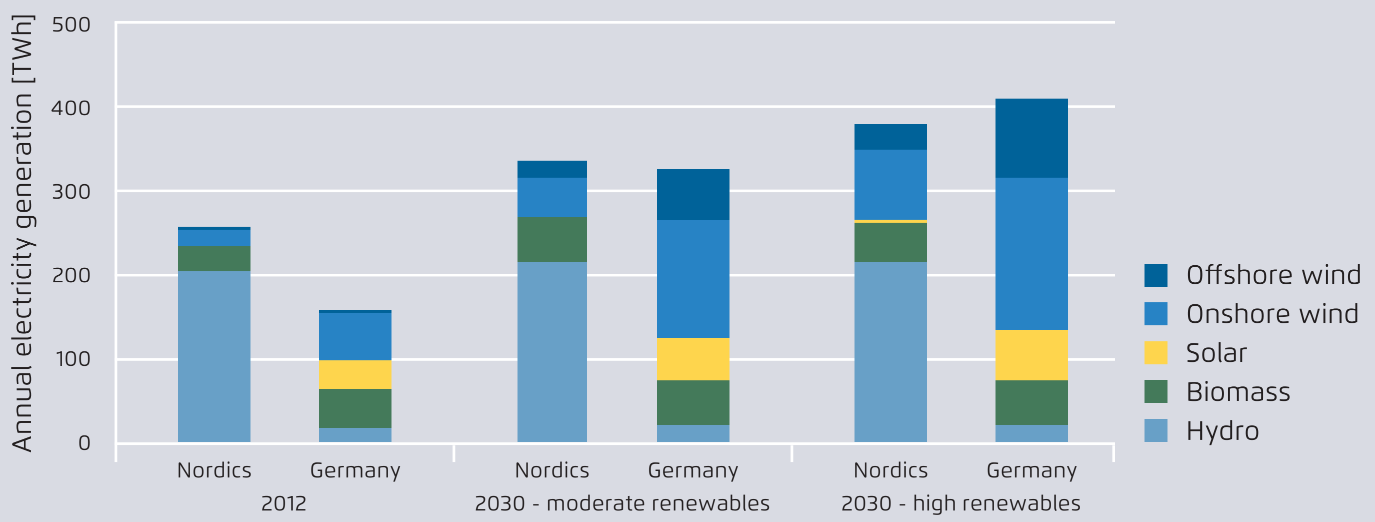
The initial model was set up with aggregated time resolution to determine investment and the decommissioning of generation capacity as well as weekly values for hydropower production for the year 2030. These results are used as exogenous parameters in a second model set up with

Renewable energy deployment and integration scenarios for 2030 — Table 2

| | Moderate Renewable scenario | High Renewable scenario |
|---|---|---|
| Moderate integration of grids | ModRE_ModTrans | HighRE_ModTrans |
| High integration of grids | ModRE_HighTrans | HighRE_HighTrans |

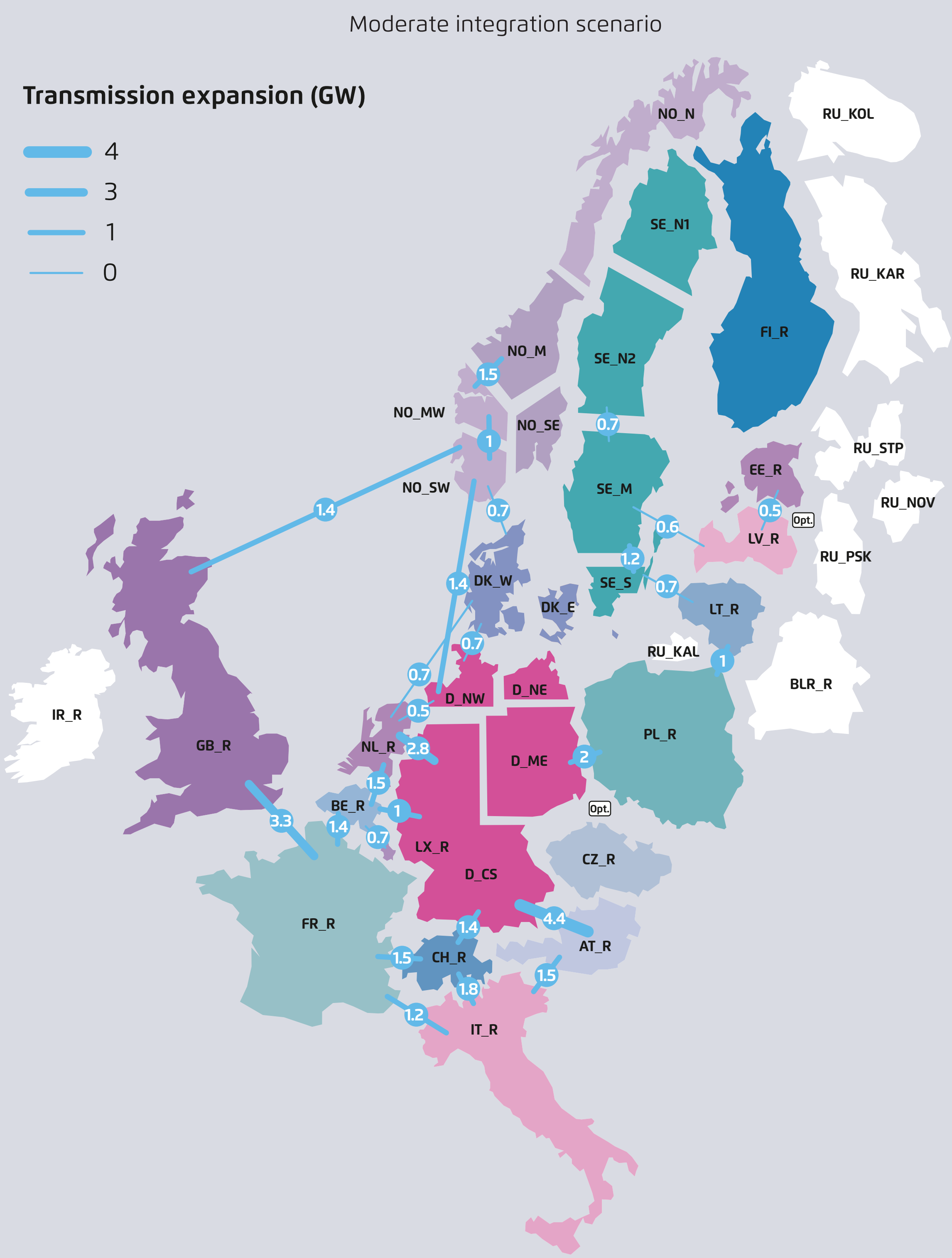
Ea and DTU (2015)

Scenario assumptions on renewable energy output in the Nordic region and Germany — Figure 2




Ea and DTU (2015)

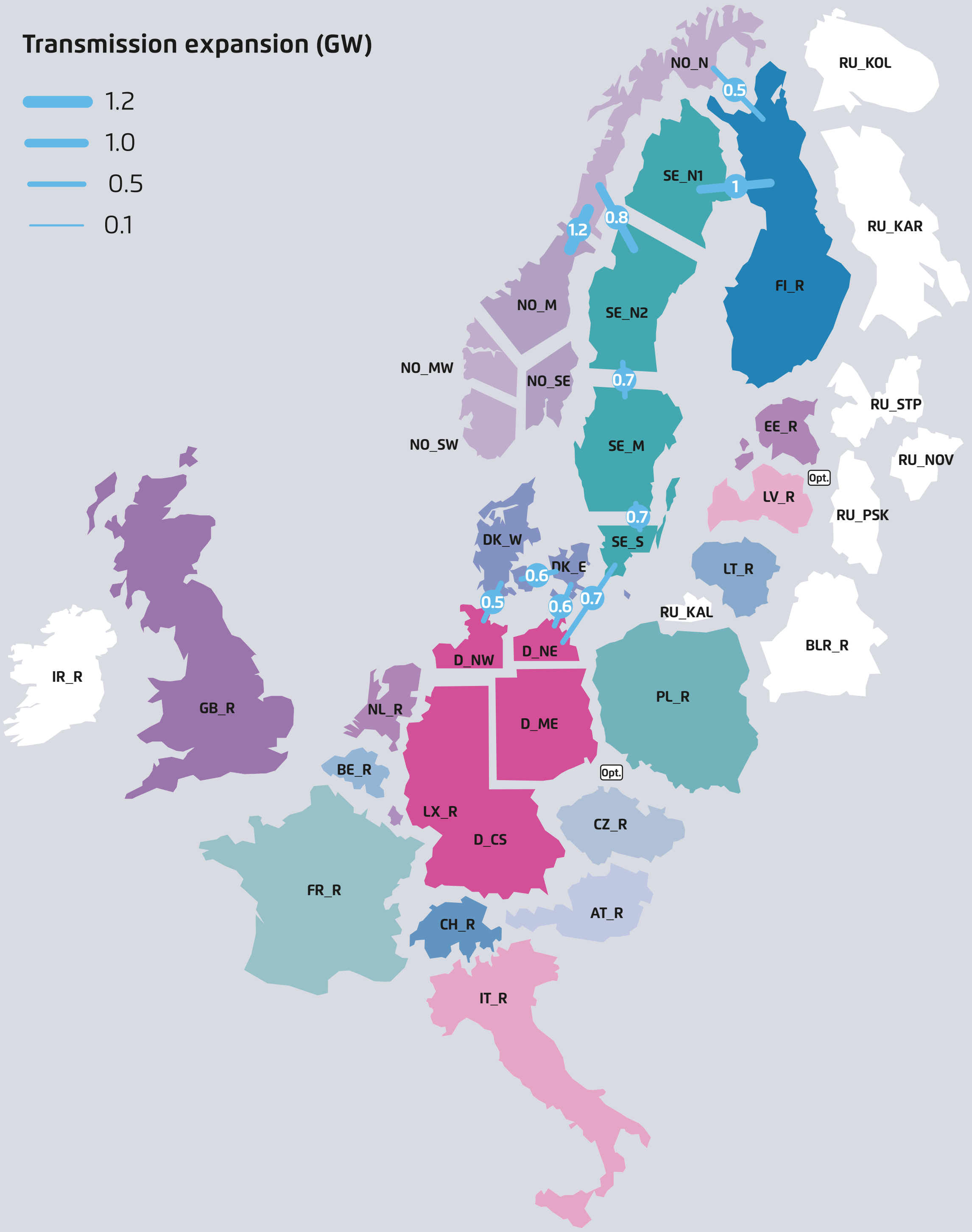
Moderate and high integration scenario for the Nordic region and Germany




Ea and DTU (2015)

Figure 3

High integration scenario



Additional transmission lines in the High Transmission scenario* — Table 3

| Project | From | To | Capacity (MW) | Year | Estimated cost range (€ millions) |
|---|---|---|---|---|---|
| **Core Countries** | | | | | |
| Westcoast | DK_W | DE_NW | 500 | 2022 | 170–210 |
| Hansa PowerBridge | SE_S | DE_NE | 700 | 2025 | 200–400 |
| 3rd AC Finland-Sweden | SE_N1 | FI_R | 1,000 | 2025 | 64–120 |
| Finland-Norway | NO_N | FI_R | 500 | 2030 | 300–700 |
| Norway-North Sweden | NO_N | SE_N2 | 750 | 2030 | 140–330 |
| East Denmark-Germany | DK_E | DE_NE | 600 | 2030 | 500–610 |
| **Internal Reinforcements** | | | | | |
| NordBalt Cable Phase 2 | SE_S | SE_M | 700 | 2023 | 170–270 |
| Res in mid-Norway | NO_M | NO_N | 1,200 | 2023 | 870–1,500 |
| Great Belt II | DK_W | DK_E | 600 | 2030 | 390–480 |
| Sweden north-south | SE_M | SE_N2 | 700 | 2030 | 800–1,400 |

Ea and DTU (2015), based on TYNDP; *The total annualised cost range lies between 208 and 348 million EUR at an interest rate of 4 percent and 30-year lifetime, and between 289 and 483 million EUR at an interest rate of 5 percent and 20-year lifetime (Ea and DTU, 2015).

an hourly time resolution. Minimising variable costs, the second step optimises only market dispatch and provides hourly economic market results for the entire year.

Work Package 1 (Ea and DTU, 2015) describes the methodology, assumptions and results of the quantitative part. Altogether, four scenarios combine the different assumptions, both for renewable deployment and for system integration (Table 2). The results provide insight into the benefits and distributional effects that would result from stronger integration of the Nordic region and Germany in two renewable-energy development scenarios.

The scenarios forecast the effects of "moderate" and "high" renewable generation capacity development (Figure 2). Higher deployment means mostly higher levels of onshore and offshore wind power. The network expansion scenarios implement TYNDP projects, which increase trade capacity between two bidding zones. The High Transmission scenario (with high grid integration) includes additional lines in the Nordic region and Germany that are planned for commissioning between 2020 and 2030 (Figure 3).[1] These projects allow better cross-border integra-

1 In the following, when referring to the scenarios of this study, "high integration" will be used synonymously for the High Transmission scenario.

Cost effects of high integration in the Moderate and High Renewable scenario* Table 4

| mn EUR/year | Moderate Renewable scenario | | | | | High Renewable scenario | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | NO | SE | FI | DK | DE | NO | SE | FI | DK | DE |
| Capital costs | 0 | 2 | 8 | -2 | -12 | 1 | -37 | 0 | -3 | 41 |
| Fixed O&M costs | 0 | 0 | 4 | 0 | -4 | -2 | -22 | 59 | 1 | 8 |
| $CO_2$ costs | 0 | -4 | -8 | 0 | 51 | -1 | -2 | 17 | 0 | 73 |
| Variable costs | 0 | -1 | 0 | -2 | 9 | -1 | -4 | 5 | -3 | 10 |
| Fuel costs | 0 | -9 | -12 | -50 | 75 | -8 | -14 | 26 | -67 | 109 |
| Water value | -13 | 24 | -12 | 0 | 0 | -29 | -2 | 9 | 0 | 0 |
| Non-supplied electricity | 0 | 0 | 0 | 0 | 0 | 0 | 0 | -3 | 0 | 0 |
| Total | -13 | 14 | -20 | -54 | 119 | -40 | -81 | 113 | -72 | 242 |

Ea and DTU (2015), *Positive values indicate benefits (i.e. cost reductions) and negative values indicate additional costs.

tion in northern Scandinavia (among Norway, Sweden and Finland), strengthen internal links (in Norway, Sweden and Denmark) and increase capacity between Germany and the Nordic region (in the Baltic Sea, from Sweden and Denmark).

Table 3 lists all individual projects with a planned date of operation and a lower and an upper bound for the estimated cost ranges. Cross-border trade capacity increases between the Nordic countries and Germany (1800 MW) and in northern Scandinavia between Norway, Sweden and Finland (2250 MW). Internal grid strengthening affects Norway (1200 MW), Sweden (700 MW) and Denmark (600 MW). While the Nordic market has multiple bidding zones, the German and the Finnish single bidding zones are still in place, not taking internal transmission constraints into account. Thus, the analysis applies a zonal electricity sector model that does not consider adjustment of the market results due to intra-zonal network congestion.

The quantitative results of the model with respect to infrastructure and system costs at the national and system levels are discussed in the technical report of Work Package 1 (Ea Energy Analyses and DTU, 2015). The report concludes that additional integration of the Nordic and German electricity markets will provide economic benefits, resulting primarily from lower $CO_2$ emission costs and savings in fuel costs (Table 4).

Work Package 1 (Ea and DTU, 2015) focuses, from an aggregate cost perspective, on the electricity market and system results of increased integration between the Nordic and German electricity systems. Another important factor that has been receiving increased attention in policy debates is the question of distributional effects. At issue are both distributional effects between countries and distributional effects between different kinds of stakeholders within a single country. The remainder of this section extends the discussion of system costs to electricity prices and distributional effects at the national and stakeholder levels. To this end, prices and rents for consumers and producers (conventional and renewables) are analysed more closely. This discussion builds on the hourly model results from Work Package 1. The following sections 4 to 6 then provide a deeper qualitative analysis of the implications for residential and industrial consumers, national and regional network planning, and the market integration of cross-border transmission capacity.

## 3.2 Price and distributional effects of system integration

The remainder of this section discusses price and rent effects at the stakeholder level, based on the quantitative results from Work Package 1 (Ea and DTU, 2015). It also analyses the costs and benefits of system integration at the national level. Below, we first sketch the basic mechanisms and methodology used to analyse prices, rents and costs.

The **price results** in Work Package 1 state average wholesale electricity prices (in the following referred to as unweighted prices) for all hours and bidding zones in every country. Section 3.2.1 of this report goes deeper into the details and discusses the price effects that system integration has on individual stakeholders, i.e. on consumers as well as producers, according to whether the technologies are conventional, hydro-power or wind power. The specific price effects for consumers can deviate from general unweighted price effects if hourly load levels are correlated to those hours with predominantly high prices or if load is geographically concentrated in bidding zones where zonal prices differ from the national average price. From the point of view of generation, different technologies supply the market at different hours and are thus exposed to price changes to a varying extent.

The **distributional effects** for stakeholders are the focus of section 3.2.2. Redistribution of stakeholder rents results from changes in hourly wholesale electricity prices, generation levels and trade flows. Our analysis of distributional effects is based on energy-only market results and thus does not have to take into account changes in the fixed costs of generation capacity and transmission lines. The analysis compares the results of the Moderate and High Transmission scenarios, both for the Moderate and High Renewable scenario.

The hourly model run of the electricity market model in Work Package 1 minimises the sum of all variable cost components ($CO_2$ costs, variable costs, fuel costs, water value and non-supplied electricity). Figure 4 illustrates the basic mechanism by which additional trade capacity between two countries A and B yields a reduction in overall variable system costs.[2] Country B utilises additional generation capacity and exports to country A, where more expensive supply is replaced. While this analysis does show the national distribution of electricity supply costs (see Table 4), it does not provide any insight into distributional market effects, i.e. into which participants gain and lose in the electricity market from additional trade.

Our analysis of redistribution between market participants addresses the effects of trade between countries A and B from a different perspective. While the results of the cost minimising electricity market model are the same as those discussed here, it is not the costs of electricity supply but rather electricity prices as well as generation and trade levels that we analyse. Figure 5 illustrates how lower prices in country A yield a redistribution from producer to consumer rents, both by means of lower prices and lower generation levels. The opposite effect is observed in country B. Domestic demand remains at the same level as with integration, given that the model assumes price inelasticity for consumers of electricity.[3] Prices do not converge completely, which results in a so-called "congestion rent". Producers in country B receive less than consumers in country A are willing to pay. This congestion rent is calculated as the product of the hourly price spread and the trade flow. As additional network capacity increases trade levels but lowers the price spread, it can affect congestion rent levels in both directions (see sections 5.1 and 5.3.1). The calculation is applied to the Nordic region and Germany

2 For convenience, Figure 4 and Figure 5 have the same supply function in the integration scenario. With the initial investment model run, conventional generation capacities can differ between moderate and high integration, i.e., the Moderate and High Transmission scenarios, which may also alter distribution effects.

3 The report of Work Package 1 includes a sensitivity run that analyses the effect of flexibility in demand.

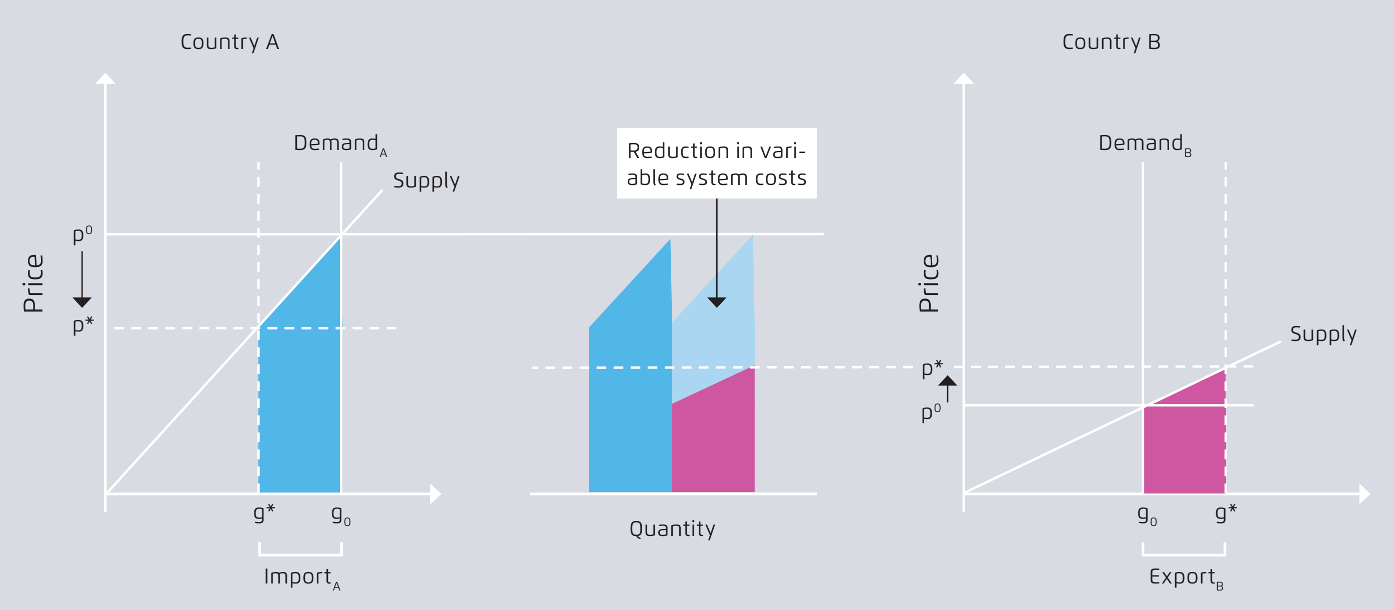
by aggregating the results from all zones and hours at the national level to annual changes in the distribution for different stakeholders.

Congestion rent is collected by the TSOs and stated separately in the results. Cross-border rents should be shared according to criteria agreed upon by the involved TSOs. A common approach is to share the congestion rent in equal measure between the two parties. According to EU regulations, "any revenues resulting from the allocation of interconnection shall be used for the following purposes: (a) guaranteeing the actual availability of the allocated capacity; and/or (b) maintaining or increasing interconnection capacities through network investments, in particular in new interconnectors" (Regulation (EC) No 714/2009, Art. 16(6)). Thus, congestion rents are not additional profits for network owners but are for the most part socialised for the benefit of stakeholders, leading to a reduction in payments for the transmission system.

Finally, our **combined analysis of costs and benefits** (section 3.2.3) compares the net benefits and losses of redistribution (section 3.2.2, Table 6) to the additional fixed costs for generation capacity (section 3.1, Table 4). Moreover, this analysis qualitatively discusses additional infrastructure costs for cross-border and internal transmission investment at the national level. The building blocks of the analysis are the following:

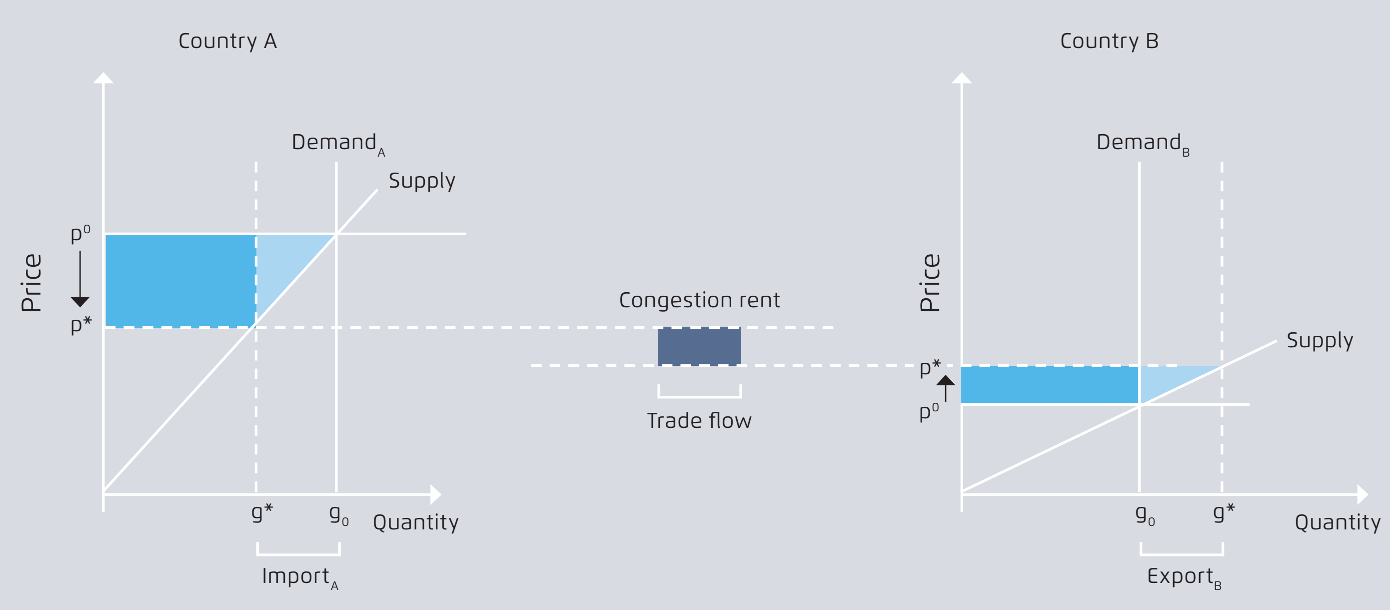
- → Integration affects the market result and thereby alters the rents from generation capacity, the network and power consumption. These effects determine who actually pays for the costs of power generation and who collects the profits. Our analysis of costs and benefits integrates changes in stakeholder rent aggregated at a national level.
- → The model results of the investment run in Work Package 1 provide the infrastructure costs of conventional generation capacity and fixed O&M costs (comprising salaries for employees and other costs that are independent of operating hours) that can be aggregated into national cost components.
- → In addition, investment in transmission lines is necessary to increase trade capacity between bidding zones in the high integration scenario (i.e., High Transmission scenario). Therefore, cross-border and cross-zonal

Reduction in variable system costs with integration — Figure 4




Own illustration

Distributional effects between consumers, producers and congestion rents with integration | Figure 5




Own illustration

lines (Table 3) are supplemented by intra-zonal network enforcement, which is often required for hinterland integration.

Bringing all of the costs and benefits together involves combining the national costs of integration with the redistribution effects of integration. Our results provide an indication of the extent to which costs and benefits are distributed at equal levels among the countries involved.

These insights motivated part of the qualitative discussion on transmission investment and the market integration of transmission capacity (sections 5 and 6), which then also address the issues of cost allocation and redistribution in the electricity sector.

### 3.2.1 Electricity prices by country and stakeholder

**National electricity prices converge in the integration scenarios**

Integration of the Nordic and German electricity systems with additional interconnector capacity has implications for the distribution of costs and prices among consumers and producers. Distributional price effects materialise along two dimensions:

→ across countries or regions,[4] respectively, and
→ across stakeholders, that is, across residential and industrial consumers and generators.

The price that consumers have to pay for electricity is comprised of several components: energy and supply, network tariffs, and taxes and levies. Prices in the quantitative model shed light on the energy component – that is, on the wholesale price excluding mark-ups (e.g. for sales and supply). In the following, we use the term **electricity price to mean wholesale electricity price** unless otherwise.

The renewable scenarios describe two possible futures for the regional electricity sectors. In the High Renewable scenarios with additional supply from wind power in the

4 In addition to the country level, national electricity markets can have multiple price zones (bidding zones). The quantitative model results assume the zones as of today with five in Norway, four in Sweden and two in Denmark. Germany and Finland have one national price zone.

National (unweighted) electricity prices in the different scenarios* Table 5

| EUR/MWh | Moderate Renewable scenario | | | High Renewable scenario | | |
|---|---|---|---|---|---|---|
| | Mod-Trans | High-Trans | Change | Mod-Trans | High-Trans | Change |
| Norway | 48.89 | 51.26 | +2.37 | 25.10 | 30.33 | +5.23 |
| Sweden | 48.97 | 51.06 | +2.09 | 27.79 | 29.76 | +1.97 |
| Finland | 47.95 | 50.40 | +2.45 | 31.22 | 30.61 | -0.61 |
| Denmark | 53.60 | 55.55 | +1.95 | 41.51 | 46.06 | +4.55 |
| Germany | 57.51 | 57.35 | -0.16 | 51.07 | 50.75 | -0.32 |

Ea and DTU (2015); *The table states the average value of all hourly and zonal electricity prices within one country. The average system price has been 38.10 EUR/MWh for the Nordic region and 37.78 EUR/MWh for Germany in 2013 (NordREG, 2014).

Nordic system and higher renewable shares in Germany, prices in Norway, Sweden and Finland are about 40 percent lower (15-20 EUR/MWh) than in the Moderate Renewable scenario (Table 5). This effect is less pronounced in Denmark (9-12 EUR/MWh) and Germany (6-7 EUR/MWh), thus increasing the price spread across the rest of the Nordic market.

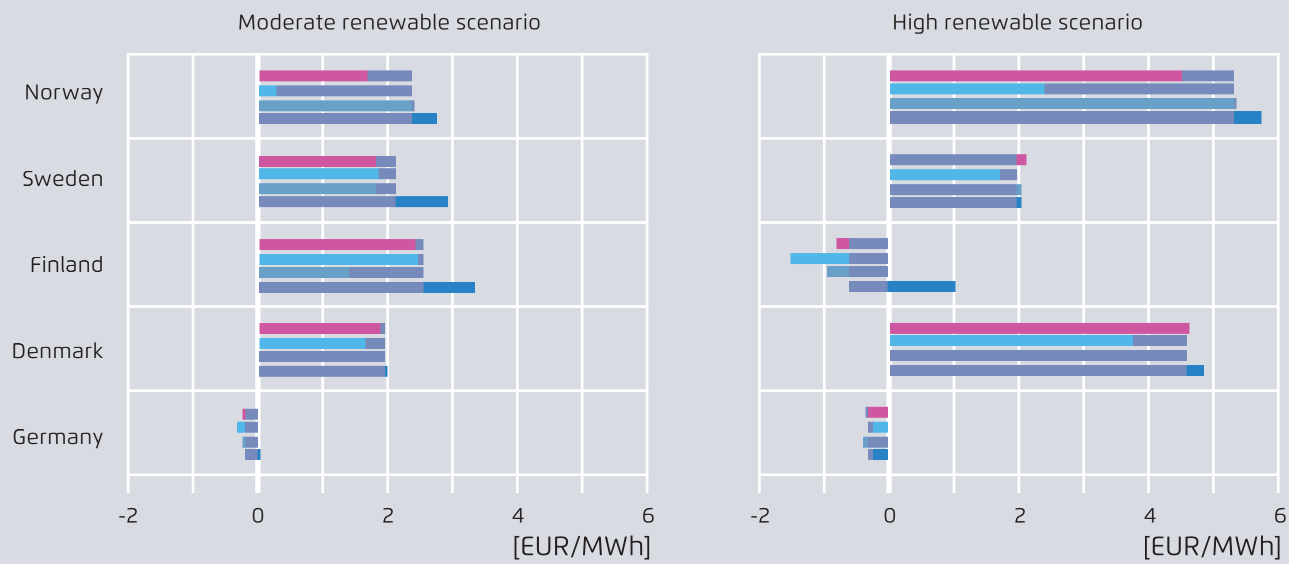
A central finding of the quantitative analysis hold true in both renewable deployment scenarios: electricity prices converge with additional trade capacity in the high integration scenarios (i.e., High Transmission scenarios), meaning higher prices in the Nordic region and slightly lower prices in Germany. The effect doubles in the High Renewable scenarios for Norway, Denmark and Germany and remains at the same level for Sweden. Finland is the only country where the reverse effect is observed, i.e. where we see decreasing prices converging to Norwegian and Swedish price levels with additional integration.

**Changing price levels affect stakeholders to varying degrees**

Integration entails price convergence for both renewable scenarios but unevenly affects stakeholders in the countries under consideration. Additional transmission capacity fosters a rise in electricity prices in the Nordic countries and a moderate price decline in Germany. In relation to the German system, the Nordic market is smaller in size and less integrated with neighbouring systems. Thus, additional transmission capacity has stronger effects on electricity prices in the Nordic region. For a more complete picture, Figure 6 depicts the weighted price effect from integration separately for consumer demand, conventional generation, and producers of hydro- as well as wind power. Unweighted prices state the average price of all zones and hours at the national level. The weighted price includes hourly information about the temporal and zonal correlation between load, generation and zonal market prices. By taking into account the hourly and zonal electricity prices, we can calculate the individual price effects at the stakeholder level, which deviate from the change in unweighted prices.

In the Moderate Renewable scenario, the change in weighted prices is for the most part in line with unweighted prices. Consumers in the Nordic countries face price increases of around 2 EUR/MWh, amounting to at most 5 percent compared to the price level in the Moderate Transmission scenario, while German consumers experience a small drop in price. Only in Norway is the increase in consumer prices considerably lower than the

Change in electricity price for integration weighted by supply and demand | Figure 6




| €/MWh | Moderate Renewable scenario | | | | | High Renewable scenario | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | NO | SE | FI | DK | DE | NO | SE | FI | DK | DE |
| Unweighted prices | +2.37 | +2.09 | +2.45 | +1.95 | -0.16 | +5.23 | +1.97 | -0.61 | +4.55 | -0.32 |
| Consumers | +1.68 | +1.80 | +2.33 | +1.87 | -0.17 | +4.43 | +2.11 | -0.79 | +4.55 | -0.31 |
| Conventional | +0.28 | +1.85 | +2.38 | +1.65 | -0.27 | +2.34 | +1.72 | -1.51 | +3.73 | -0.25 |
| Hydro power | +2.35 | +1.79 | +1.35 | – | -0.20 | +5.22 | +2.03 | -0.93 | – | -0.39 |
| Wind power | +2.75 | +2.90 | +3.21 | +1.98 | +0.06 | +5.61 | +2.04 | +1.03 | +4.82 | -0.25 |

Ea and DTU (2015) and own calculation

unweighted average. Zonal electricity prices in Norway increase more than the average in the northern price zones, while the largest share of demand is located in the southern zones. In the High Renewable scenario, qualitatively, the same findings prevail, but with higher overall price effects as a result of integration. A discussion on the exposure to electricity prices of particular consumer groups is provided in section 4.

The prices electricity producers receive depend on when and how much they supply to the market. Small and inflexible electricity systems will see stronger price depressions in hours of high wind and solar power availability. This effect decreases with increased supply and demand side flexibility (e.g. with additional storage capacity and demand-side management) as well as with better integration to neighbouring electricity systems.

In general, the integration of the Nordic and German markets provides producers with additional profits from higher average prices in the Nordic countries and with losses from lower prices in Germany. Seasonal hydro-storage in Norway and Sweden is often considered to be the main beneficiary of integration due to the inter-temporal flexibility of its generation, which allows for positive interactions with wind power generation in the North and Baltic Seas region. Therefore, stronger integration provides opportunities for trade in both directions.

The price results do not provide clear indications concerning price mark-ups for hydro-storage, which could benefit from integration. In the Nordic market, additional transmission capacity supports the integration of additional wind power, which sees a higher than average price increase. Hydro-power in Norway and Sweden is in line with the average price increase, while conventional generation receives less than average benefits, especially in the high renewable scenario. In Germany, any differences from the already moderate price effects are small.

### 3.2.2 Rent distribution by country and stakeholder in the energy-only market

**At the stakeholder level, every country sees winners and losers from integration**

The above price effects can be aggregated in order to conduct a distributional analysis of rents. Specifically, we took a closer look at changes in consumer payments as well as profits for different producers in the energy-only market. Generally, compared to between-country effects, **the levels of redistribution are significantly higher across stakeholder groups**. On the one hand, additional integration benefits producers in countries with increasing prices and, on the other, consumers in countries with decreasing prices. Here, electricity prices in the moderate grid integration scenarios (ModTrans) represent the base case. Figure 7 provides an overview of changes in rents for the Moderate Renewable scenario.[5]

The redistribution effects are strongest within the Nordic countries. Higher average prices earn Nordic hydro-power producers additional profits of 450 million EUR and wind power producers an additional 190 million EUR. While hydro-power profits mostly in Norway and Sweden, gains for wind generation are allocated more evenly across all Nordic countries. In Denmark, for instance, wind generation is the biggest beneficiary of integration. Likewise, conventional generation in the Nordic region profits from higher grid integration, as increased exports allow for additional generation and higher prices, thus making nuclear energy the biggest single winner in Sweden and Finland. As opposed to generator profits in the Nordic region, wholesale electricity prices, as part of the electricity bill, increase payments made by consumers by more than 750 million EUR in the Nordic countries. At the same time, additional network capacities entail less congestion rent. Congestion rents obtained from inter-zonal congestion decrease for the most part along internal lines in northern Norway as price spreads decrease with the better system integration of regional excess renewable capacity.[6]

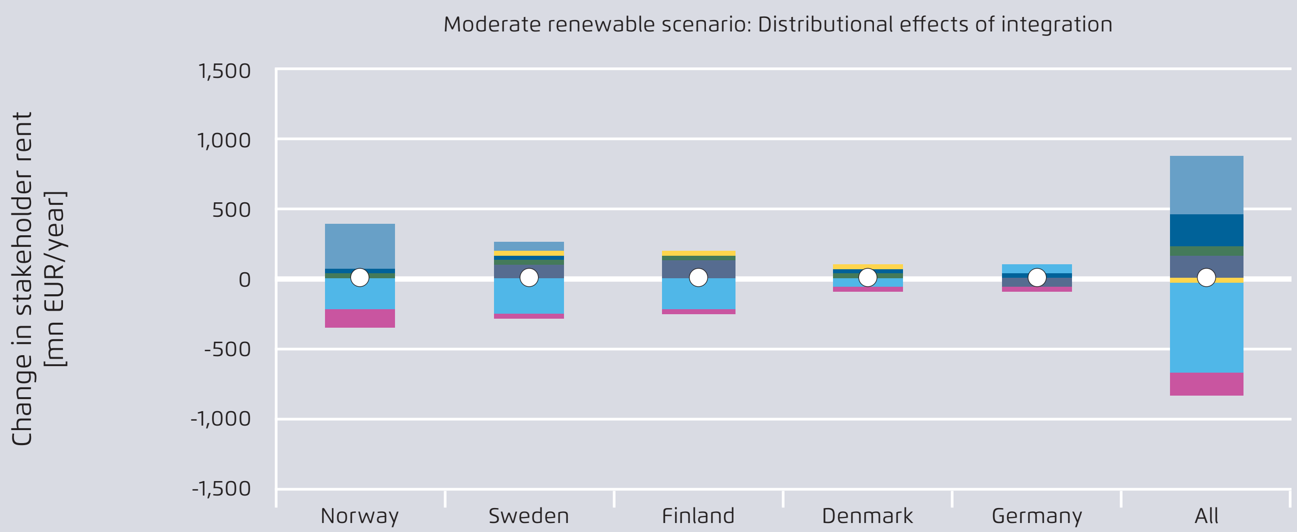
For Germany, the reverse picture prevails, though distributive effects are rather moderate as compared to the Nordic countries. With the additional import of cheap electricity, consumers see their total electricity payments lowered by almost 100 million EUR. Most producers, especially conventional units, lose profits. Only wind production is among the beneficiaries of integration, with a moderate increase in profits. The merit order effect decreases with system integration. During hours with high wind generation, exports to Norway and Sweden result in more stable electricity prices in Germany.

In the High Renewable scenario (Figure 8), effects are analogous to the moderate scenario, although more pro-

5 Hydro-power includes the effect of remaining water values per country from the quantitative results (see section 3.1); cost for electricity that is not supplied is added as a cost to consumer rents. National values cover rents collected between zones within the country, while rents on cross-border lines are shared in equal parts.

6 Congestion rent is calculated as the product of hourly price spread and trade flow. The calculation is applied for the Nordic region and Germany by aggregating results of all zones and hours on the national level to annual changes in the distribution for different stakeholders. Congestion rent is collected by the TSOs and in the results it is assumed that congestion rent on cross-border trade capacity is shared in equal measure between the two parties involved. According to EU regulations, "any revenues resulting from the allocation of interconnection shall be used for the following purposes: (a) guaranteeing the actual availability of the allocated capacity; and/or (b) maintaining or increasing interconnection capacities through network investments, in particular in new interconnectors" (Regulation (EC) No 714/2009, Art. 16(6)). Thus, congestion rents are not additional profits for network owners but are for the most part socialised to the benefit of stakeholders, providing for a reduction in payments for the transmission system.

Distributional integration effects at the stakeholder level (moderate renewable) Figure 7




| | Norway | Sweden | Finland | Denmark | Germany | All |
|---|---|---|---|---|---|---|
| Congestion rent | -128 | -9 | -1 | -17 | -10 | -165 |
| Consumers | -233 | -250 | -219 | -63 | 91 | -673 |
| Hydro power | 336 | 92 | 28 | 0 | -4 | 452 |
| Photovoltaic | 0 | 0 | 0 | 1 | -5 | -4 |
| Wind power | 59 | 49 | 29 | 55 | 13 | 204 |
| Biomass | 0 | 27 | 34 | 15 | -12 | 64 |
| Conventional | 1 | 103 | 128 | 5 | -50 | 188 |
| Total country | 35 | 12 | -1 | -5 | 34 | 75 |

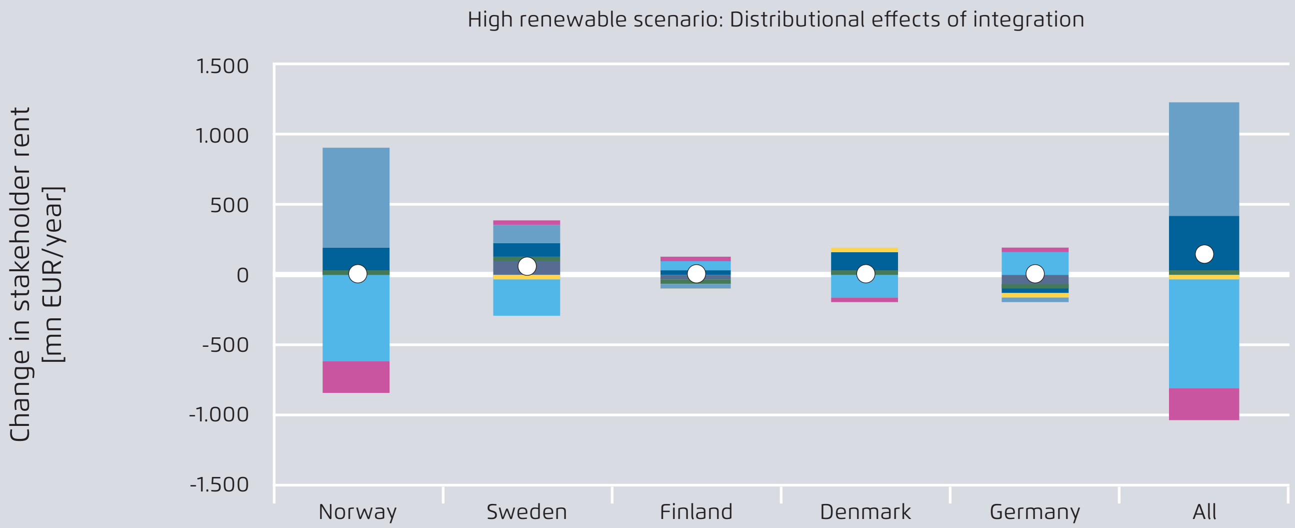
Ea and DTU (2015) and own calculation

nounced. Additional renewable deployment, however, also yields some different findings. Germany, among the greatest beneficiaries under moderate renewable deployment, now profits less. This result is driven by the rents for wind power: here, integration now triggers decreasing profits, as it leads to more imports of excess generated in the Nordic region and less of a balance between the two regions. In Finland, which is a net importer under the High Renewable scenario, consumers profit from integration and, except in the case of wind power, producers lose profits.

In the remaining countries, redistribution levels from consumers to producers are highest in Norway (900 million EUR), followed by Sweden (300 million EUR) and Denmark (150 million EUR). Except for nuclear power, which gains 100 million EUR in Sweden, increased rents are collected by the producers of renewable energy (mainly wind and hydro-power). While congestion rents decrease in Norway, Sweden collects 50 million EUR in congestion rents with additional transmission investment.

The net benefit for the entire region is higher than the change in variable system costs. Neighbouring countries (e.g. the United Kingdom and Poland) cover the difference of 25 million EUR. They also experience distributional effects from the additional system integration that are not discussed in this study.

Distributional integration effects at the stakeholder level (high renewable) Figure 8




| | Norway | Sweden | Finland | Denmark | Germany | All |
|---|---|---|---|---|---|---|
| Congestion rent | -262 | 49 | 5 | -24 | 2 | -299 |
| Consumers | -615 | -294 | 71 | -154 | 170 | -821 |
| Hydro power | 730 | 128 | -22 | 0 | -8 | 829 |
| Photovoltaic | 0 | -1 | 0 | 2 | -15 | -14 |
| Wind power | 199 | 89 | 16 | 146 | -68 | 381 |
| Biomass | 1 | 36 | -14 | 24 | -14 | 34 |
| Conventional | 0 | 107 | -47 | 7 | -58 | 10 |
| Total country | 54 | 115 | 10 | 1 | 10 | 191 |

Ea and DTU (2015) and own calculation

**Integration mostly benefits Norway and Germany in the Moderate Renewable scenario and Sweden in the High Renewable scenario**

To summarise, market integration causes a redistribution of stakeholder rents. Table 6 provides an overview of the effects, summarising the shifts in national gains and losses while taking into account consumer rents, generator profits and congestion rents, but excluding additional infrastructure costs for generation and transmission.

For the region as a whole, rents increase in both grid integration scenarios (ModTrans and HighTrans scenarios), yet more so in the High renewables scenario. As price changes are asymmetric, integration triggers an uneven redistribution. The biggest beneficiaries in terms of market rents are Norway and Germany under the moderate scenario and Sweden and Norway under high deployment scenario. In other countries, the effects on the whole are moderate and non-uniform, which might seem surprising, especially in the case of Denmark, in view of its central location as a transit country.

Distributional effects of integration on national socioeconomic welfare (additional value of increased integration (HighTrans) as compared to moderate integration (ModTrans) scenario) Table 6

| mn EUR/year | Moderate Renewables | High Renewables |
|---|---|---|
| Norway | +35 | +54 |
| Sweden | +12 | +115 |
| Finland | -1 | +10 |
| Denmark | -5 | +1 |
| Germany | +34 | +10 |
| Total | +75 | +191 |

Ea and DTU (2015) and own calculation.

### 3.2.3 National system cost combined with rent distribution in the energy-only market

This section combines the results on system costs and market outcomes to arrive at a more comprehensive assessment of the integration of the Nordic and German electricity systems. Figure 9 illustrates how the different steps of the study relate to this analysis. The results of the energy-only market model were analysed in-depth with regard to distributional effects in section 3.2.2. The following discussion of national costs and benefits considers the cost perspective, i.e. the capital and fixed costs of power generation facilities, and qualitatively discusses investment in transmission infrastructure in the high integration scenario (HighTrans).

Overall, our approach aims to distinguish between the cost components of the national electricity systems and the various means by which they are paid for. We focus on changes in costs and payments in the high integration scenario (HighTrans) compared to the Moderate Transmission scenario. Our comparison of costs and benefits on the national level therefore addresses:

- → differences in capital and fixed costs for generation capacity between the Moderate and High Transmission scenarios, optimised in the initial investment run with an aggregated time resolution (see scenario assumptions and results of the investment model in section 3.1, Table 4);
- → net national benefits/losses resulting from distributional changes in the hourly model results over the en-

Study sequence – from the investment model, energy-only market model, distributional effects, and the analysis of costs and benefits Figure 9

| 1) Investment model (Ea and DTU) | 2) Energy-only market model | 3) Distributional effects (DIW Berlin) | 4) Costs vs. benefits |
|---|---|---|---|
| Cost optimal investment and decomissioning of conventional generation capacity | Energy-only market with hourly market outcome | Distributional effects of system integration in the energy-only market on national level | Combining capital costs, fixed O&M costs, distributional effects on national level and discussion on transmission costs |
| **Output:**<br>→ Generation capacity<br>→ Capital and fixed O&M costs | **Output:**<br>→ Generation levels<br>→ Trade flows<br>→ Electricity prices | **Output:**<br>→ Stakeholder rents<br>→ National benefits | **Output:**<br>→ Costs and benefit on national level |

Own illustration

tire year between the Moderate and High Transmission scenarios (section 3.2.2, Table 6).

In general, the cost components of the electricity system include fixed costs for renewable and conventional capacity, variable generation costs and the costs of the transmission system.

The fixed costs of renewable capacities do not change in the Nordic and German electricity systems between the Moderate and High Transmission scenarios. In today's electricity markets, investment in renewable technologies is primarily incentivised by national subsidy schemes. The coordination and cost-allocation of renewable deployment in possible multi-national schemes and related cross-border effects are not discussed in this study. In this report, additional national capacity payments, which are potentially necessary to cover fixed costs of renewable and conventional capacity, are discussed only briefly with a view to their potential impact on interconnector investment.

The fixed costs of conventional capacity can change in the High Transmission scenario, as conventional capacity, in contrast with the exogenous scenario assumptions for renewable capacity, is optimised endogenously beyond scheduled decommissions. The initial optimisation in the investment model determines endogenous investment in as well as the shut-down of conventional generation capacity. The results are fixed costs for investment and O&M in the Moderate and High Transmission scenarios at the national level. These costs are not included in the distributional analysis of the energy-only market. In the following, they are part of the discussion of national benefits. Variable generation costs are already considered in the analysis of the distributional effects of the energy-only market. Subtracted from the income from electricity sales by generators, they affect the profits of producers.

For transmission costs, we distinguish between lines that are cross-border, national inter-zonal (between bidding zones), and national intra-zonal (within bidding zones). A limited share of the transmission costs is recovered by congestion rents collected in the energy-only market. The level of national congestion rents can change in the High Transmission scenario, as shown in section 3.2.2. The allocation of congestion rents for cross-border projects and additional internal congestion rents in countries with several bidding zones affect the distribution in the energy-only market. The results of the energy-only market, so far, assume an equal share of cross-border congestion rents, while internal congestion rent remains within the country of origin. However, these results are not related to the costs of the transmission investments.

The High Transmission scenario includes additional cross-border projects between the Nordic and German electricity systems and also cross-zonal transmission projects for countries when there are multiple bidding zones in place. National projects within a single bidding zone (i.e. all projects in countries that have only one bidding zone) are not specified. While the cost allocation of cross-border lines is negotiated between the countries involved, the cost of necessary hinterland integration is mostly translated into national transmission tariffs. In the case of an asymmetric allocation of benefits, a more general perspective on cost allocation for cross-border and relevant internal network investment may be required to overcome national hurdles.

In sum, in the following we discuss the distributional effect of additional system integration, including market benefits as well as the capital and fixed costs of generation capacity at the national level. We conclude the section with a qualitative discussion of transmission investment costs.

**Benefits can compensate for higher system costs in most countries in the Moderate Renewable scenario**

The results of the analysis for the Moderate Renewable scenario indicate that most countries will benefit from system integration. Compared with higher system costs (Table 4) in Norway (13 million EUR), Finland (20 million EUR) and Denmark (54 million EUR), distributional effects in the energy-only market more than compensate for higher costs in Norway and Finland. From a system cost viewpoint, Denmark is the only country to see ben-

Change in national rents under the Moderate Renewable scenario — Table 7

| mn EUR/year | Capital costs | Fixed O&M costs | Energy-only market | Benefits excl. network |
|---|---|---|---|---|
| Norway | – | – | +35 | **+35** |
| Sweden | +2 | – | +12 | **+14** |
| Finland | +8 | +4 | -1 | **+12** |
| Denmark | -2 | – | -5 | **-7** |
| Germany | -12 | -4 | +34 | **+18** |
| Total | -5 | – | +75 | **+70** |

Own calculation

Change in national rents under the High Renewable scenario — Table 8

| mn EUR/year | Capital costs | Fixed O&M costs | Energy-only market | Benefits excl. network |
|---|---|---|---|---|
| Norway | +1 | -2 | +54 | **+53** |
| Sweden | -37 | -22 | +115 | **+56** |
| Finland | – | +59 | +10 | **+69** |
| Denmark | -3 | +1 | +2 | **0** |
| Germany | +41 | +8 | +10 | **+59** |
| Total | +3 | +44 | +191 | **+238** |

Own calculation

efits decrease with increased integration.[7] While Germany can reduce its national costs of electricity generation by 119 million EUR (Table 4; with most savings in fuel and $CO_2$ cost as a result of lower generation levels), it can realize only 18 million EUR in net benefits.

7 Note that in practice, due to the variable production pattern of wind energy, there may still be some additional value of increased integration for Denmark that is not considered in this system cost analysis.

**Most countries benefit between 50 and 70 million EUR per year in the High Renewable scenario**

Under the High Renewable scenario, a picture emerges that is similar to the Moderate Renewable scenario. Total benefits derived within the model are higher, and the spread across countries is more balanced. Except for Denmark, all countries benefit in the range of 53 million EUR (Norway) to 69 million EUR (Finland). In Finland and Germany, these gains are mostly driven by lower costs for national power production. Integration allows domestic production to be substituted for cheaper imports. On the other hand, Norway and Sweden profit most due to increased opportunities to export their hydro-production at higher prices. Within the model, Denmark sees no net benefits from integration in terms of system costs, neither under the Moderate nor under the High Renewable scenarios. However, the smoothing out of increasingly variable wind feed-in by imports and exports could be an additional benefit that would add significant value.

**Discussion of cross-border and national network costs**

In our analysis of benefits and costs thus far line upgrades are assumed to be exogenous, and the necessary expenses to build the new lines have not been included. Generally, there are three types of transmission network investments in our setting: cross-border lines connecting two countries, cross-zonal lines connecting two price zones within one country, and intra-zonal lines. The first two types are explicitly addressed in the scenario definitions, while the latter type could be critical in facilitating further integration.

All lines are subject to specific investment costs. For lines connecting two countries, one could assume as the simplest sharing rule that costs are equally distributed across the countries directly involved. However, other schemes are possible. The difficult question that must be addressed in order to arrive at a sound solution that sets appropriate incentives relates to who actually benefits most from the integration triggered by the interconnector. Our quantitative and qualitative analysis of the distributional effects of integration sheds some light on this issue. Section 5 provides a broader discussion of the economics of interconnector investments.

The lines drawn between two price zones within a single country can basically be regarded as national projects. Beyond facilitating the spatial equalisation of supply and demand and the integration of renewables and/or enhanced security of supply within a single country, in broader terms these lines lead to greater integration of a larger region – as has been shown in the quantitative and qualitative analyses in this report. Intra-zonal lines are not explicitly taken into account, and price zones are treated as copper plates. Nonetheless, they are important for the hinterland integration of cross-border interconnectors because they are needed to accommodate altered flows resulting from new import or export possibilities. At the same time, as is also the case with cross-zonal lines, it is difficult to disentangle the share of internal line upgrades that are used predominantly for the purposes of hinterland integration from other ends – for instance, that of aligning a spatially changing generation pattern with demand or network security considerations.

Therefore, a simple comparison of the benefits identified in this study with cost estimates for different types of network investments is beyond the scope of this analysis. Rather, this qualitative discussion is intended to raise concerns relevant to distribution and absolute rents and to isolate only those factors necessary for the discussion of projects against this background.

The north-south network enforcement projects in Sweden and Germany are illustrative. While network enforcement allows for the better system integration of increasing renewable capacity (hydro- and wind power) in the northern part of Sweden, this increasing capacity is also needed for increased trade using the interconnectors to neighbours in the south. In Germany, national network investment is driven by the changing spatial distribution of supply and demand. For instance, efforts are underway to integrate growing onshore and offshore wind capacity in the northern part of the country with the load centres in the west and south. Cables from the Nordic system already connect to this region of northern Germany with its large wind capacities. Hinterland network flows within Germany are reduced whenever electricity is exported to the Nordic system during those hours of high wind availability. If the Nordic system becomes an exporter of electricity, as considered in the High Renewable scenario, a more continuous export flow to the south would require capacity on the north-south transmission lines within Germany.

Today, the typical situation is one in which national tariffs provide the means for national transmission investments, and these tariffs are for the most part imposed on national consumers (the relevance of which will be discussed in section 4). In the absence of proper incentives to move ahead with system integration, national strategic considerations could instead effectively delay integration. This issue is addressed at the European level in our discussion of different approaches for dealing with benefits and network costs (section 5). The proper allocation of costs according to benefits remains a challenge given the difficulty of balancing national needs with cross-border importance.

# 4 Qualitative Discussion for Residential and Industrial Consumers

Electricity is an important and functional energy carrier. Both residential and industrial consumers use it to operate a wide range of appliances and machinery. Substitution of electricity with other energy carriers is difficult in many of its various applications. At the same time, residential and industrial electricity demand varies considerably between countries. This section describes the national structures of residential and industrial electricity demand in the Nordic region and Germany, and also discusses the consequences of changes in wholesale electricity price levels.

## 4.1 Exposure of residential consumers to electricity prices

Residential electricity demand varies considerably among the countries of the region (Table 9). Private consumer demand is lowest in Germany, at 1700 kWh per person and year, and considerably higher in the Nordic countries. Demand is more than twice as high in Sweden and Finland. It is the highest in Norway, at over 7700 kWh per person and year. We can trace these deviations in residential electricity demand per capita to an overall higher consumption of energy in the Nordic countries and to the higher share of electricity in total energy demand. Lower electricity prices have historically incentivised electric heating, especially in Norway and Sweden. Final consumer prices are below 18 cent/kWh in Norway and Finland, about 20 cent/kWh in Sweden, and highest in Denmark and Germany, at close to 30 cent/kWh (Table 10). These final prices include, in addition to the wholesale price, network tariffs as well as taxes and levies. Consumers in the Nordic countries are more exposed to increases in wholesale electricity prices because of their higher per capita consumption.

In the model results for 2030, the price for the energy component (i.e. the wholesale electricity price excluding the supply component) remains similar to that of today, if not smaller. The High Renewables scenarios point towards savings mostly in the energy component in the Nordic countries. The comparability of model results and today's wholesale prices is, however, somewhat limited: model results only comprise the energy component, while the current price level also includes a sales component. On the other hand, current prices in the energy-only market do not cover fixed costs for all power plants. In the model runs with endogenous investment, construction of new and the decommissioning of existing conventional power plants is conducted to the point that all installations recover their fixed costs in the energy-only market.

Future integration is therefore not expected to impact residential consumers in an especially adverse way. Moreover, future electricity consumption by private customers depends on concrete utilisation patterns, which are uncertain as of today. For instance, the electricity demand for heating in Norway and Sweden could be substituted in part by other fuels like gas or biofuels, or it might be lowered by more and better insulation. Moreover, the advent of "smart" home appliances or the electrification of further sectors such as individual mobility could alter patterns of demand towards greater temporal flexibility. Increased responsive-

Residential electricity demand — Table 9

| | Residential demand | Average consumption |
|---|---|---|
| | GWh | kWh/capita |
| Norway 2012 | 38,573 | 7,736 |
| Sweden 2012 | 35,086 | 3,672 |
| Finland 2013 | 21,510 | 3,946 |
| Denmark 2012 | 14,285 | 2,560 |
| Germany 2013 | 138,400 | 1,719 |

Statistical Offices of the countries

Residential electricity prices in 2013 for power consumption of 2500–5000 kWh/year — Table 10

| cent/kWh | Energy and supply | Network tariff | Taxes and levies | Total |
|---|---|---|---|---|
| Norway | 5.22 | 7.57 | 4.99 | 17.78 |
| Sweden | 5.65 | 7.56 | 7.25 | 20.46 |
| Finland | 6.03 | 4.84 | 4.72 | 15.59 |
| Denmark | 4.83 | 7.66 | 16.86 | 29.35 |
| Germany | 8.66 | 6.23 | 14.32 | 29.21 |

Eurostat (2015a)

ness, together with further time-varying contracts, could mitigate consumer exposure to price spikes but also enhance demand during low-price phases.

## 4.2 Industrial electricity prices

Competitiveness of energy-intensive industries is a sensitive matter for industrial policy. Countries with low electricity prices generally have a relative advantage and may accordingly maintain or attract energy-intensive manufacturing firms. Table 11 renders an account of current industrial electricity prices in 2013 for large manufacturing firms with annual power consumption between 70 and 150 GWh/year. As of today, industrial electricity prices are considerably lower in Norway, Sweden and Finland than in Denmark and Germany. Final prices are highest in Germany, at almost 10 cent/kWh. In Denmark, they are somewhat below 9 cent/kWh. In Norway, Sweden and Finland, they range between 5 - 6 cent/kWh. A qualitatively similar picture emerges for industrial customer groups with lower power consumption, although they see higher levels for non-energy and supply cost components. Lower final prices are driven both by the wholesale price, which is highest for Germany, and by low taxes and network charges. The share of energy and retail in final prices ranges between 64 percent and 85 percent for Norway, Sweden and Finland, whereas in Denmark and Germany, it amounts to 45 percent and 51 percent, respectively.

For the biggest consumers in the power-intensive manufacturing industry, the observed pattern can be more pronounced: Table 12 renders figures on manufacturing electricity prices in Norway by industrial group, broken down into the energy component and transmission tariff but excluding taxes and levies. Two main observations prevail: first, at 0.24 cent/kWh, the average grid tariff for large power-intensive industrial customers is of only minor relevance, also when compared to the group of large firms with consumptions below 150 GWh/year; second, for non-power-intensive manufacturing, the energy price for electricity is higher than for the power-intensive industries, but only by approximately 10 percent. The grid tariff, however, amounts to 2.19 cent/kWh and is thus more than eight-fold. A qualitatively similar finding holds for the construction, service, and public sectors.

**Renewable deployment levels have a strong effect on regional industry electricity prices**

In connection with the quantitative model results, the conclusion can be drawn that the differences in price between the High and the Moderate Renewable scenarios would have a large impact on industrial energy prices. Higher prices resulting from integration would unfold with a comparatively moderate impact, although a change of 0.2 - 0.4 cent/kWh in the energy component is not negligible. Except for Denmark, the risk that energy-intensive industry would suffer from an increasing cost block aris-

Average electricity prices for industrial consumers of 70–150 GWh/year — Table 11

| cent/kWh | Energy and supply | Network costs | Taxes and levies | Total |
|---|---|---|---|---|
| Norway | 3.57 | 0.60 | 0.14 | 5.61 |
| Sweden | 4.49 | 0.74 | 0.01 | 5.29 |
| Finland | 4.71 | 0.57 | 0.70 | 5.98 |
| Denmark | 3.93 | 3.83 | 0.90 | 8.66 |
| Germany | 4.91 | 1.30 | 3.50* | 9.71 |

Eurostat (2015b); *Additional exemptions exist for companies exposed to international competition. For individual firms, taxes and levies can be significantly lower.

Electricity prices for selected power-intensive manufacturing sectors in Norway 2012 — Table 12

| | Total price excl. taxes | Price on electricity | Electricity share | Network tariff |
|---|---|---|---|---|
| | cent/kWh | cent/kWh | % | cent/kWh |
| **Power intensive manufacturing** | 3.67 | 3.42 | 93 | 0.24 |
| Pulp and paper | 3.96 | 3.68 | 93 | 0.27 |
| Industrial chemicals | 4.29 | 3.79 | 88 | 0.49 |
| Iron, steel and ferroalloys | 3.63 | 3.44 | 95 | 0.19 |
| Non-ferrous metals | 3.41 | 3.25 | 95 | 0.16 |
| **Non power intensive manufacturing** | 5.82 | 3.76 | 65 | 2.06 |
| Food products, beverages and tobacco | 5.99 | 3.80 | 63 | 2.19 |
| Other manufacturing | 5.74 | 3.75 | 65 | 1.99 |
| **Construction and other services** | 7.08 | 4.25 | 60 | 2.82 |

Statistics Norway (2015c), exchange rate from ECB, own calculations.

ing from transmission charges that would have in turn arisen as an effect of network investment is relatively low, considering the industrial network tariff is low and payments are mainly collected from other power consumers—although, one must also take into account that an increase in network fees for other consumer groups could generate political pressure to distribute costs more evenly.

## 4.3 Electricity demand in energy-intensive industries

In the Nordic countries and Germany, electricity demand within the manufacturing sector varies greatly, both with respect to overall demand and its distribution across branches of industry. Likewise, the relative weight of different branches of industry varies in terms of employment, turnover and value-added. The distributional effects for industrial electricity consumers that result from changes in national electricity prices can therefore be expected to have an uneven impact on different branches of industry. Analysing the impacts that will result from stronger integration for industrial consumers provides a basis for understanding and shaping targeted policy measures. The following section takes a closer look at the relevance of electricity as an input in the manufacturing sector.

**Industrial electricity demand varies across countries and sectors**

Table 13 presents descriptive statistics for electricity consumption within manufacturing, differentiated by branch (NACE codes 10 – 33).[8] Within the Nordic region, power consumption in manufacturing is considerably higher in Norway (43 TWh), Sweden (49 TWh) and Finland (39 TWh), as compared to Denmark (11 TWh), which does not have a large electricity-intensive industrial sector. German industrial electricity consumption is by far the greatest, at 218 TWh.

Likewise, the relative share of industrial branches qua electricity consumers varies. In Norway, Sweden and Finland, the pulp and paper industries, petroleum, chemicals and pharmaceuticals manufacturing, and the basic metals industry are the largest industrial consumers of electricity, though with varying degrees of relevance. While pulp and paper manufacturing consumes 22 TWh in Sweden (46 percent of total industrial electricity demand) and 18 TWh in Finland (47 percent of total industrial electricity demand), the manufacturing of basic metals in Norway is, at 24 TWh (56 percent of industrial electricity demand), by far the largest industrial consumer of electricity in Norway. There is, accordingly, a high concentration of industrial electricity demand coming from a single sector. Denmark has no single large energy-consuming industry, while power consumption is more evenly spread over several branches of industry in Germany.

**Relevance of industries with high electricity consumption**

High shares in electricity demand from a specific branch of industry does not necessarily translate to high shares of employment, turnover, or value-added within that branch. For a more differentiated view, consumption is therefore discussed here in relation to employees, turnover, and value-added for the high energy-consuming manufacturing sectors.

Table 14 provides an overview of employment figures. The three largest electricity-consuming industrial branches in Norway, Sweden and Finland – e.g. pulp and paper, refined petroleum, chemicals, pharmaceuticals and basic metals – are not particularly large in terms of employment. The manufacturing of basic metals in Norway, for example, employed 10,000 persons in 2012, amounting to four percent of the total industrial sector employment. While pulp and paper consumes over 45 percent of industrial demand for electricity in Sweden, this branch employs only five percent of the manufacturing workers. The largest employers are the machinery and vehicle industries. Analogous pictures emerge for Finland and Germany. In Denmark, with its overall low industrial electricity consumption, high shares in employment and electricity use are seen in the food industry.

A similar though not so pronounced finding is also seen for turnover of the manufacturing sector (Table 15). The contribution to total manufacturing turnover is disproportionately lower in the largest electricity-consuming sectors when compared to demand for electricity as a production input.

8 The NACE (Nomenclature statistique des activités économiques dans la Communauté européenne) is a harmonised measure at the European level. It classifies economic activities according to their main output products. Data is retrieved from the national statistical offices.

**Electricity intensive manufacturing**
Tables 13–15 can be combined to yield a measure of electricity intensity per sector. To this end, electricity consumption is divided by the number of employees and by figures for turnover and value-added. Table 16 depicts these ratios.

Beyond the high absolute electricity consumption in the sectors 1) pulp and paper, 2) refined petroleum, chemicals, pharmaceuticals and 3) basic metals in Norway, Sweden and Finland, these sectors are also the most *electricity-intensive*. Electricity intensity, in this respect, takes into account employment (MWh/employee) and turnover (MWh per million EUR). For Denmark and Germany, this is not necessarily the case. These electricity-intensive branches of manufacturing are relevant sectors for the respective national economies in terms of employment, turnover, and value added, but their relevance does not correspond to the relevance of electricity as an input in their production processes. Especially for their role as employers, their

Electricity demand by industry branch — Table 13

<table>
<tr><th colspan="2"></th><th>Norway* 2012</th><th>Sweden 2012</th><th>Finland 2013</th><th>Denmark 2012</th><th>Germany 2013</th></tr>
<tr><td colspan="2">Total electricity demand of national manufacturing (ThW)</td><td>43</td><td>49</td><td>39</td><td>11</td><td>218</td></tr>
<tr><td>NACE code</td><td colspan="6">Industry branches (%)</td></tr>
<tr><td>10–12</td><td>Food, beverages, tobacco</td><td>6</td><td>5</td><td>5</td><td>28</td><td>8</td></tr>
<tr><td>13–15</td><td>Textile and leather</td><td>–</td><td>0</td><td>1</td><td>1</td><td>0</td></tr>
<tr><td>16</td><td>Wood, wood products</td><td>2</td><td>4</td><td>4</td><td>3</td><td>2</td></tr>
<tr><td>17</td><td>Pulp, paper</td><td>9</td><td>46</td><td>47</td><td>2</td><td>9</td></tr>
<tr><td>18</td><td>Print</td><td>–</td><td>1</td><td>1</td><td>2</td><td>1</td></tr>
<tr><td>19–21</td><td>Refined petroleum, chemicals, pharma</td><td>19</td><td>12</td><td>16</td><td>21</td><td>27</td></tr>
<tr><td>22/23</td><td>Rubber, plastic, non-metallic minerals</td><td>3</td><td>5</td><td>5</td><td>16</td><td>12</td></tr>
<tr><td>24</td><td>Basic metals</td><td>56</td><td>16</td><td>15</td><td>5</td><td>18</td></tr>
<tr><td>25</td><td>Fabricated metals except machinery</td><td rowspan="5">6</td><td>3</td><td>3</td><td>6</td><td>7</td></tr>
<tr><td>26/27</td><td>Computer, electronic, optical</td><td rowspan="2">4</td><td>2</td><td>3</td><td>5</td></tr>
<tr><td>28</td><td>Machinery, equipment</td><td>2</td><td>9</td><td>1</td></tr>
<tr><td>29/30</td><td>Vehicles, transport</td><td>4</td><td>1</td><td>1</td><td>8</td></tr>
<tr><td>31–33</td><td>Furniture, other, repair</td><td>1</td><td>1</td><td>5</td><td>2</td></tr>
</table>

Statistical Offices of the countries; *For Norway, figures for textile and leather, print and industries with codes 25 to 33 are aggregated.

Employees by industry branch — Table 14

| | | Norway 2012 | Sweden 2012 | Finland 2013 | Denmark 2012 | Germany 2013 |
|---|---|---|---|---|---|---|
| **Employment per industry** | | **231,000** | **546,000** | **315,000** | **261,000** | **6,122,000** |
| NACE code | Industry branches (%) | | | | | |
| 10–12 | Food, beverages, tobacco | 21 | 9 | 11 | 18 | 11 |
| 13–15 | Textile and leather | 1 | 1 | 3 | 2 | 2 |
| 16 | Wood, wood products | 6 | 5 | 6 | 3 | 1 |
| 17 | Pulp, paper | 1 | 5 | 7 | 2 | 2 |
| 18 | Print | 3 | 2 | 3 | 2 | 2 |
| 19–21 | Refined petroleum, chemicals, pharma | 5 | 6 | 6 | 11 | 8 |
| 22/23 | Rubber, plastic, non-metallic minerals | 7 | 7 | 8 | 9 | 9 |
| 24 | Basic metals | 4 | 6 | 4 | 2 | 4 |
| 25 | Fabricated metals except machinery | 10 | 12 | 12 | 11 | 10 |
| 26/27 | Computer, electronic, optical | 6 | 11 | 13 | 9 | 12 |
| 28 | Machinery, equipment | 9 | 13 | 14 | 20 | 16 |
| 29/30 | Vehicles, transport | 12 | 12 | 5 | 2 | 15 |
| 31–33 | Furniture, other, repair | 11 | 8 | 9 | 10 | 7 |

Statistical Offices of the countries and own calculations

relative weight is lower compared to other manufacturing sectors. Likewise, concerning value-added, pulp and paper and basic metals, which are very energy-intensive industries, contribute less than seven percent each to the total industrial figure.

**Industrial structure and industrial electricity prices**
Low industrial electricity prices in Norway, Sweden and Finland go hand in hand with a developed energy-intensive manufacturing sector that benefits from this advantage. More generically, the question arises as to whether energy prices drive a country's sectoral specialisation. Basic economic theory suggests that comparative advantages (in factor input prices and factor abundance) foster specialisation.[9] Energy prices are, however, just one component. Path dependencies, inter-sectoral spillovers shared infrastructure and the accumulation of a knowledge stock add to the difficulty in evaluating how changing energy prices could impact a country's industrial performance.

9 This line of reasoning goes back to David Ricardo (1772-1823), and Swedish economists Eli Heckscher and Bertil Ohlin.

Manufacturing turnover in manufacturing by sector — Table 15

| | | Norway 2012 | Sweden 2012 | Finland 2013 | Denmark 2012 | Germany 2013 |
|---|---|---|---|---|---|---|
| **Turnover by industry (bn €)** | | **93** | **203** | **120** | **87** | **1,792** |
| NACE code | Industry branches (%) | | | | | |
| 10–12 | Food, beverages, tobacco | 24 | 10 | 8 | 21 | 11 |
| 13–15 | Textile and leather | 1 | 1 | 1 | 1 | 1 |
| 16 | Wood, wood products | 4 | 5 | 5 | 2 | 1 |
| 17 | Pulp, paper | 1 | 7 | 16 | 2 | 2 |
| 18 | Print | 2 | 1 | 1 | 1 | 1 |
| 19–21 | Refined petroleum, chemicals, pharma | 9 | 15 | 7 | 16 | 17 |
| 22/23 | Rubber, plastic, non-metallic minerals | 6 | 5 | 5 | 8 | 6 |
| 24 | Basic metals | 11 | 7 | 6 | 1 | 5 |
| 25 | Fabricated metals except machinery | 6 | 7 | 6 | 7 | 6 |
| 26/27 | Computer, electronic, optical | 5 | 11 | 26 | 8 | 10 |
| 28 | Machinery, equipment | 11 | 12 | 13 | 22 | 12 |
| 29/30 | Vehicles, transport | 12 | 15 | 3 | 2 | 24 |
| 31–33 | Furniture, other, repair | 8 | 4 | 3 | 9 | 4 |

Statistical Offices of the countries and own calculation

A full-fledged analysis is beyond the scope of this report. Nevertheless, Zachmann and Cipollone (2013) analyse European industrial specialisation and competitiveness against the background of electricity prices between 1996 and 2011. What they discover is that low electricity prices indeed tend to coincide with specialisation in energy-intensive industries. Simple intuition would suggest causality, which is, however, not necessarily maintained here.

Put conversely, the competitiveness of energy-intensive industries may be made vulnerable by increasing electricity prices. A study on electricity prices in the manufacturing sector in Europe, carried out for the German Federal Ministry for the Environment, Nature Conservation and Nuclear Safety (Ecofys, 2014), emphasises this vulnerability: for large and energy-intensive industrial customers, the cost of electricity supply is primarily driven by the wholesale price. Various exemptions and reductions for taxes and surcharges considerably reduce the additions to the wholesale price for electricity supply. For small and medium – and not explicitly energy-intensive – enter-

Electricity intensity of manufacturing per employee, turnover, and value added — Table 16

<table>
<tr><th rowspan="2">Industry branches (%)</th><th>NO</th><th>SE</th><th>FI</th><th>DK</th><th>DE</th><th>NO</th><th>SE</th><th>FI</th><th>DK</th><th>DE</th><th>NO</th><th>SE</th></tr>
<tr><th colspan="5">Employment (MWh/employee)</th><th colspan="5">Turnover (MWh/m €)</th><th colspan="2">Value-added (MWh/m €)</th></tr>
<tr><td>Food</td><td>54</td><td>48</td><td>53</td><td>66</td><td>26</td><td>119</td><td>123</td><td>177</td><td>169</td><td>91</td><td>490</td><td>576</td></tr>
<tr><td>Textile</td><td></td><td>23</td><td>25</td><td>39</td><td>4</td><td></td><td>121</td><td>147</td><td>124</td><td>22</td><td></td><td>354</td></tr>
<tr><td>Wood</td><td>50</td><td>68</td><td>78</td><td>43</td><td>55</td><td>196</td><td>208</td><td>236</td><td>198</td><td>230</td><td>683</td><td>1,104</td></tr>
<tr><td>Pulp, paper</td><td>1,100</td><td>768</td><td>838</td><td>54</td><td>147</td><td>2,920</td><td>1,576</td><td>940</td><td>185</td><td>511</td><td>14,117</td><td>6,446</td></tr>
<tr><td>Print</td><td></td><td>21</td><td>31</td><td>35</td><td>26</td><td></td><td>104</td><td>201</td><td>169</td><td>169</td><td></td><td>292</td></tr>
<tr><td>Refined petrol, chemicals</td><td>647</td><td>181</td><td>327</td><td>77</td><td>129</td><td>988</td><td>185</td><td>784</td><td>164</td><td>198</td><td>4,089</td><td>704</td></tr>
<tr><td>Non-metallic materials</td><td>77</td><td>58</td><td>67</td><td>73</td><td>46</td><td>227</td><td>208</td><td>272</td><td>261</td><td>227</td><td>756</td><td>685</td></tr>
<tr><td>Basic metals</td><td>2,394</td><td>231</td><td>438</td><td>128</td><td>158</td><td>2,324</td><td>516</td><td>789</td><td>422</td><td>407</td><td>15,032</td><td>2,687</td></tr>
<tr><td>Fabricated metals</td><td rowspan="5">100</td><td>26</td><td>26</td><td>24</td><td>24</td><td rowspan="5">389</td><td>122</td><td>145</td><td>111</td><td>147</td><td>1,024</td><td>344</td></tr>
<tr><td>Electronic</td><td rowspan="2">33</td><td>15</td><td>13</td><td>14</td><td rowspan="2">88</td><td>20</td><td>45</td><td>63</td><td></td><td>331</td></tr>
<tr><td>Machinery</td><td>18</td><td>18</td><td>1</td><td>54</td><td>50</td><td>5</td><td></td><td></td></tr>
<tr><td>Vehicles</td><td>25</td><td>19</td><td>24</td><td>20</td><td>66</td><td>87</td><td>78</td><td>43</td><td></td><td>280</td></tr>
<tr><td>Other</td><td>13</td><td>14</td><td>20</td><td>8</td><td>61</td><td>95</td><td>63</td><td>48</td><td></td><td>174</td></tr>
<tr><td>Average</td><td>181</td><td>90</td><td>123</td><td>43</td><td>36</td><td>450</td><td>243</td><td>323</td><td>128</td><td>122</td><td>1,657</td><td>924</td></tr>
</table>

Statistical Offices of the countries and own calculation

prises, taxes and levies play a bigger role, as these enterprises profit from exemptions to a lesser extent.

Together with the structure of current electricity prices, this suggests two conclusions: First, the main component of electricity prices for electricity-intensive manufacturing in Norway, Sweden and Finland is the cost of the actual good, i.e. the electricity itself. Therefore, varying electricity prices will have a non-negligible impact on the cost structure of those branches in relative terms. Second, put conversely, the grid tariff and taxes and levies component is comparably low. Taxes in Sweden, for example, are below one euro per megawatt hour. There is, accordingly, limited room for policymakers to adjust to changes in the energy share of the electricity price.

**Short review of applied mitigation options towards price increases**

Channels to mitigate rising electricity prices do exist: there may be a shift towards increased on-site generation of electricity, substitution for other fuels or investments in efficiency.

An increase of auto-production of electricity – electricity that is generated on-site for the manufacturer's own consumption – is one such mitigating option. Exposure to varying electricity prices may thus be less pronounced than suggested. Ericsson et al. (2011) observes a trend toward the auto-production of electricity in the Swedish pulp and paper sector over the course of 20 years, running parallel with a steady increase in electricity prices. In the event that production also requires process heat or process steam, for instance, electricity may be generated as a by-product and rising prices for external supply may not be directly passed through.

Data on auto-production in Norway and Finland[10] shows that on-site generation is limited. In Norway, there is no industrial sector that produces more than 10 percent of its necessary electricity on-site. Likewise in Finland, most sectors draw upon the grid for electricity supply. In Finland's three most electricity-intensive sectors, the share of auto-production is somewhat higher than it is in Norway, at approximately 10 percent in basic metals manufacturing, 15 percent in refined petroleum, chemicals and pharmaceuticals and slightly below 40 percent in the pulp and paper industry.

Auto-production can play a role in mitigating exposure to varying electricity prices. However, there is always some level of opportunity cost consideration: assuming a certain input of electricity for a production process, this electricity must either be purchased from the grid or produced on-site. As the price of electricity from the grid rises, on-site production may prove more economical. However, if this on-site generation does not yield any co-benefits, like process heat or process steam, then it is rather disconnected from the production process itself. Moreover, electricity production that is disconnected to industrial processes in this way competes with electricity purchased from the grid or may be sold to the grid. In such a case, rising general electricity prices are passed on to the firm. Thus, in connection with the observed relatively low level of auto-production, industries are to a large extent exposed to the general electricity price level. In the same vein, grid tariffs or taxes and levies that could be avoided to a certain extent through on-site generation are already quite low for energy-intensive manufacturing.

There may be, however, other technical possibilities of substituting electrical energy with different other forms of energy supply, at least to a certain extent. Henriksson et al. (2012) found out that in the Swedish pulp and paper industry, the own-price elasticity of electricity is fairly low, at 0.28, meaning that electricity price increases are followed by an under-proportional decrease in electricity demand. This insensitive reaction indicates a general reliance on electricity as an input factor. Furthermore, the estimated cross-price elasticities suggest that there is some scope for substitution among energy inputs: with a one percent increase in the electricity price, the demand for fuel oil rises by 0.26 percent.

Investment into increased energy efficiency may be yet another response to increasing electricity prices. Blomberg et al. (2012) quantify an annual electricity savings potential of 1 TWh within the Swedish pulp and paper industry. Accordingly, there is some opportunity for more efficient electricity consumption that could be exploited in the event of price pressure. In a large-scale study on the manufacturing sector in OECD countries, Steinbuks and Neuhoff (2014) estimated significant impacts from energy price increases on investments in energy input efficiency for the energy-intensive chemicals and metal sectors. Investments into more efficient production are thus a means to mitigate increasing energy input costs, although these mitigating options can and do incur non-trivial costs in and of themselves.

**The vulnerability of energy-intensive manufacturing**

To some extent, strategies exist to mitigate the effects of increasing electricity prices on energy-intensive manufacturing. Nevertheless, it remains to assess from a macro perspective how vulnerable those industries are; that is whether and to what extent they can cope with adverse

10 Source: Statistics Norway (2015d), Statistics Finland (2015c), Statistics Finland (2105d)

factor-price developments beyond intra-firm accommodation.

One dimension of such vulnerability is exposure to international competition. An analysis of price-taking versus price-setting behaviour can capture the scope of opportunities for mitigating factor-price increases. In an analysis of energy-intensive industries in Europe, FitzGerald et al. (2009) estimate that especially the basic metals manufacturing sector in Sweden and Finland and the pulp and paper industry in Finland are predominantly price-takers on international markets for their output goods.[11] This particularly holds true when the German output price is used as a benchmark. Those industries have limited scope to accommodate increasing energy costs by passing them on to customers. A qualitatively similar effect was found for the chemicals industry in Sweden, although it was less pronounced.

For the macro-economic weight of the respective sectors, Zachmann and Cipollone (2013) confirm the line of reasoning suggested by the data for the Nordic countries – namely, low electricity prices coincide with specialisation in a few energy-intensive sectors with lower value-added or lower employment figures. Moreover, these sectors produce relatively homogeneous goods and face international competition. On the other hand, countries with higher electricity prices are rather specialised in high value-added or high-employment sectors. In turn, however, this does not imply that high electricity prices induce productive specialisation: causality is more complex to evaluate, and lower value-added sectors can in fact be an important part of the macro-economy.

**Synthesis with the quantitative results**

As opposed to Denmark, the other Nordic countries and Germany have a high demand for industrial electricity, which in Norway, Sweden and Finland is concentrated in a few energy-intensive sectors. Currently, those sectors – pulp and paper, basic metals and refined petroleum, chemicals and pharmaceuticals – enjoy a comparative advantage due to low industrial electricity prices. Although being rather exposed to changes in electricity prices, investments into further energy efficiency would provide these sectors with some margin with which to mitigate the effects of increasing electricity prices. Further integration of the Nordic and German electricity systems would lead to a moderate increase in those prices. However, in the Moderate Renewable scenario, this increase would be rather minor. In the High Renewable scenario, the increase in prices through integration is more pronounced. However, the initial electricity prices resulting from additional renewable deployment and moderate network investment are very low.[12] From the point of view of industrial policy, integration ought not be deemed detrimental. From a macroeconomic point of view, the energy-intensive sectors are comparable to the other manufacturing branches in their economic importance. Employment, industry revenues and value added are not as pronounced as the use of electricity as a production factor.

11 Norway was not part of the study.

12 Model results indicate prices for high integration (HighTrans scenarios) that are below current levels. Moreover, large industrial customers usually negotiate special contracts with suppliers, yielding lower prices than those observed at wholesale markets.

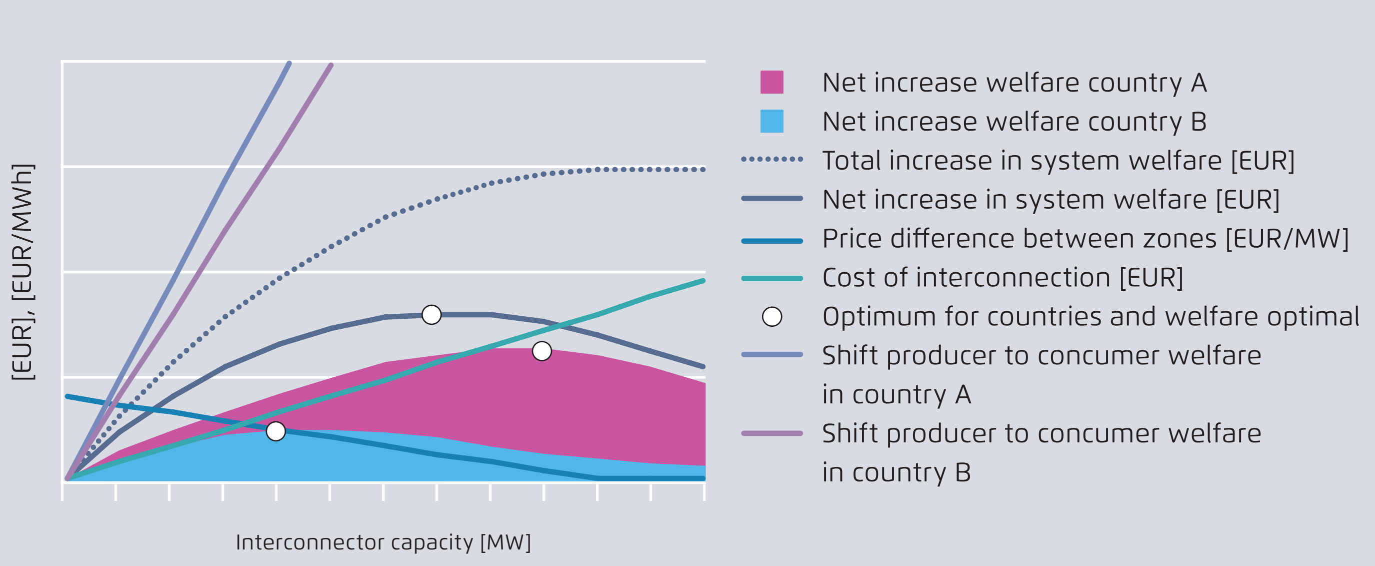
# 5 National and Regional Network Development

Quantitative model results indicate that additional network investment input in the High Transmission scenario will benefit the system. However, the asymmetric allocation of costs and benefits could prevent its realisation. This section introduces the economics of network investment and provides both a European and a bilateral perspective.

## 5.1 Interconnector economics

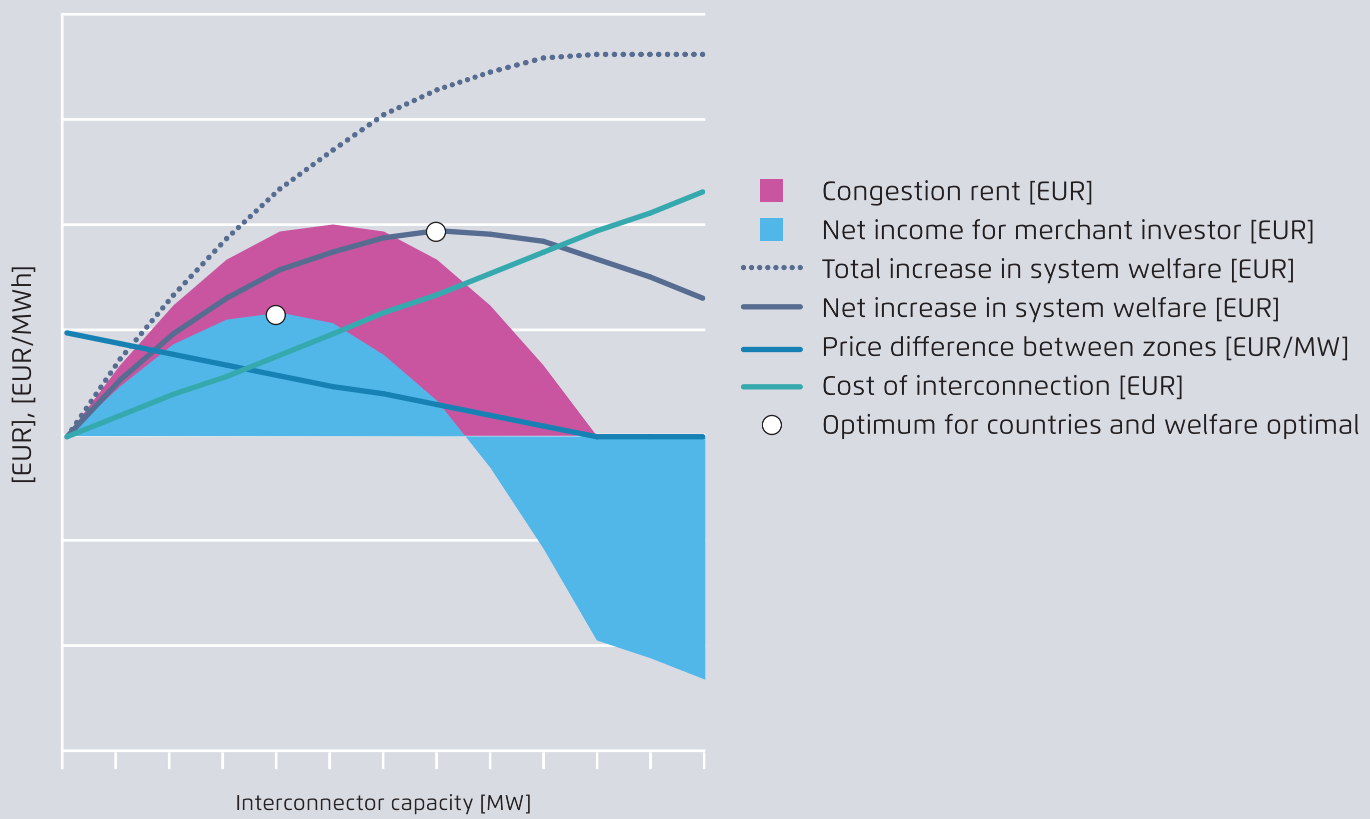
Additional interconnector capacity results in a net increase in socioeconomic welfare as long as marginal revenue from additional capacity is larger than marginal costs. Decisions concerning the desired level of market integration from a national perspective are more complicated. Figure 10 illustrates a generic situation involving national strategic decisions on interconnector investment with the goal of maximising national welfare. Optimal levels differ for both countries A and B from the welfare-optimal solution. While country B (left dot) only supports moderate extensions, country A (right dot) collects disproportionately high shares of total welfare gains and would like to build even more than the optimal total system capacity. In other words, if each country could follow its national incentives, the level of integration would be suboptimal from a global perspective, as more surpluses could always be generated – without, however, speaking directly to the distribution of such surpluses. However, the national maximisation of socioeconomic welfare is not the only national consideration. One additional effect is the convergence of electricity prices. It shifts consumer and producer welfare, with either metric increasing in one country as it decreases in the other. The quantitative results for Nordic-German integration (section 3.2) reveal distributional effects approx. 10 times more pronounced for individual stakeholders than for changes in national welfare. While the overall positive welfare effect in country B is an incentive for strong physical system integration, higher average electricity prices and the shift from consumer to producer welfare gains can induce strong national opposition to integration.

Welfare implications of interconnector investment at the country and stakeholder levels — Figure 10




Own illustration based on Supponen (2011)

System welfare and congestion rents for investment in interconnector capacity — Figure 11




Own illustration based on Supponen (2011) and Kirschen and Strbac (2004)

National strategic considerations and stakeholder opposition can undermine interconnector projects and hamper cross-border system integration that would otherwise benefit the regional electricity markets. An alternative approach to promote investment is the merchant case, which provides exceptions for third party investments. In contrast to regulated investment financed by grid tariffs, merchant cables receive their profits from arbitrary rents in the electricity market. As already mentioned, the so-called congestion rent is calculated as the difference in electricity prices of both connected price zones multiplied by the trade flow on the merchant line. In theory, merchant investors chose a lower than welfare optimal cable size in order to maximise their net income (congestion rent minus interconnector cost) in a static setting (Figure 11).

The distributional effects of price convergence and the asymmetric allocation of benefits introduce a political dimension to the economics of interconnector investment. Given this, the effect of redistribution between consumer and producer welfare may in particular be significantly greater than the net increase in social welfare resulting from investments in the North and Baltic Seas grids (see section 3.2 and Egerer et al., 2013). The asymmetric distribution of benefits with any change in cross-border market capacities – both between any two countries directly involved as well as on a larger regional level affecting all neighbouring countries – means there are inherently externalities involved with greater grid integration.

In addition, both the geographic scope of bidding zones in the European electricity market and the inter-zonal trade capacity (NTC), which is auctioned on the market, have implications for market prices and distributional effects. To account for network security and internal congestion within a single zone, TSOs define hourly NTC capacity,[13] which is generally lower than the total physical cross-zonal transmission capacity. The distributional effects of increasing this capacity can have surprising implications. For example, a study on increasing NTC capacities between Denmark-West (DK1) and Germany without any additional network upgrades shows that overall system welfare in Europe increases (Moser et al., 2014). However, the directly involved countries (Denmark and Germany) lose in all scenarios up to 35 million EUR per year since it is up to them to cover the increasing costs of redispatch. Furthermore, at the stakeholder level, rents between consumers and producers shift by 200 million EUR per year. The main beneficiary is Sweden, gaining up to 60 million EUR per year, while other countries (Italy, Switzerland, Belgium and Austria) jointly gain only as much as 20 million EUR per year.

As illustrated in Figure 10, the benefits of interconnector investment are not allocated evenly and even affect neighbouring countries not directly involved in the investment. Thus, countries could play a non-cooperative game when deciding on interconnector investment, resulting in lower than system-optimal investment levels (Nylund and Egerer, 2013 and Huppmann and Egerer, 2014). To internalise distributional aspects in decisions on transmission investment, different policies and approaches are now in place or under discussion. The following sections provide a brief introduction to the national allocation of network costs with transmission tariffication (section 5.2) and shed light on pan-European and bilateral aspects, including model results for specific HVDC links (section 5.3). Section 6 highlights possibilities for the market integration of interconnector capacity and discusses the possible impacts of bidding zones in the Nordic-German context.

13 TSOs calculate the NTCs according to methodologies approved by ENTSO-E. Usually the NTC consists of the total transfer capacity (TTC), considering network security minus a transmission reliability margin (TRM) to provide assistance to neighbouring zones if necessary (e.g. ELIA, 2015).

## 5.2 Transmission tariffication

National transmission tariffs are composed of very specific cost components, including cost allocation to the generation and load sides (the so-called generation (G) and load (L) components), energy- and power-related charges, balancing services, and locational prices. Discussing European tariffication rules, Ruester et al. (2012) argue that tariff system heterogeneity prevents a level playing field and hampers adequate investment and efficient competition. EU involvement should focus on transparency and harmonization, tariffs that do not distort the competitive sector, allocation based on causality and the removal of legal barriers for third party investment in order to incentivise investment in cross-border capacity.

The synthesis report (ENTSO-E, 2014e), summarised in Table 17, for the Nordic countries and Germany provides some transparency on tariff composition. Norway (38 percent), Sweden (33 percent) and Finland (17 percent) also allocate a portion of network costs to generation. Because a significant share of the tariff is energy-related, the tariff affects the marginal costs of electricity supply and thereby alters market dispatch as well as the distribution of stakeholder rents. Norway and Sweden also have tariffs differentiated by location. With respect to the low electricity prices in the quantitative results for Norway and northern Sweden, locational transmission tariffs for generation could reduce the distributional effects that network investment has on consumers in the High Transmission scenario by socialising higher profits from wind- and hydro-power by means of an increased transmission tariff on generators in the north.

Overview of national transmission tariff components — Table 17

| | | | NO | SE | FI | DK | DE |
|---|---|---|---|---|---|---|---|
| **Overview** | Cost sharing | G component (%) | 38 | 33 | 17 | 4 | 0 |
| | | L component (%) | 62 | 67 | 83 | 96 | 100 |
| | Price signal | Temporal differentiation | x | | x | x | |
| | | Locational differentiation | x | x | | | |
| | Losses included | | x | x | x | x | x |
| | System serviced included | | x | x | x | x | x |
| **Cost components** | OPEX | | x | x | x | x | net costs |
| | CAPEX | Depreciation | x | x | x | x | x |
| | | Return on capi-tal invested | x | x | x | x | x |
| | ITC | | costs | net bene-fits | costs | net costs | net costs |
| | Reserves | Primary | x | Partially (40 %) | | x | x |
| | | Secondary | x | | | x | x (only cap.) |
| | | Tertiary | x | | x | x | x (only cap.) |
| | Congestion management | Internal | net costs | net costs | x | net costs | x |
| | | Cross-border | net bene-fits | net bene-fits | x | net costs | x |
| | Black start | | | x | x | x | x |
| | Reactive power | | x | x | x | x | x |
| | System balancing | | | | | net costs | |
| | Losses | | x | x | x | x | x |

ENTSO-E (2014e)

Overview of national transmission tariff components — Table 17

| | | | NO | SE | FI | DK | DE |
|---|---|---|---|---|---|---|---|
| **Numbers 2014** (€/MWh) | **Total** | | **4.42** | **3.99** | **5.07** | **37.14** | **9.93** |
| | **TSO** | **Total** | **4.42** | **3.99** | **4.97** | **8.70** | **9.09** |
| | | Losses | 0.50 | 1.26 | 1.02 | 1.63 | 0.81 |
| | Components | System services | 0.40 | 0.26 | 1.00 | 0.90 | 2.34 |
| | | Infrastructure | 3.52 | 2.47 | 3.54 | 6.16 | 5.94 |
| | **Invoiced RES/ CHP subsidies** | **Total** | **0** | **0** | **0.10** | **28.44** | **0.84** |
| | Components | RES subsidies | | | | 27.86 | |
| | | Administration | | | | 0.58 | |
| | | Peak load cap. reservation | | | 0.10 | | |
| | | CHP | | | | | 0.25 |
| | | StromNEV §19 | | | | | 0.25 |
| | | AbLaV | | | | | 0.09 |
| | | Offshore wind connection | | | | | 0.25 |
| | Remarks | | * | | | | ** |
| **Energy/ power shares (%)** | Base case results, non-TSO activity related | Energy | 54 | 35 | 100 | 100 | 17 |
| | | Power | 46 | 65 | 0 | 0 | 83 |
| **Locational differentiation** (€/MWh) | | Tariffs range | (-1; 12) | (-3; 8) | | | |
| | | Remarks | | *** | | | |
| **Evolution** (€/MWh) | TSO component | 2011 | 4.59 | 3.54 | 3.21 | 9.93 | 6.39 |
| | | 2012 | 4.19 | 3.99 | 4.00 | 9.95 | 6.32 |
| | | 2013 | 3.82 | 4.17 | 4.56 | 8.73 | 7.65 |
| | | 2014 | 4.42 | 3.99 | 4.97 | 8.70 | 9.09 |
| **Special tariffs** | Various Energy-intensive | **** | | | | ***** | ****** |

ENTSO-E (2014e); *Tariff varies with price (daily), losses (weekly) and volumes. Numbers are estimations., ** Reductions for energy-.-intensive industries (>7000 full-.-load hours, >= 10GWh). Depending on full-.-load hours, tariff reduced TO 10, 15 or 20%., *** Entry fees increase linearly with latitude further north, exit fees linearly increase with latitude further south., **** Interruptible loads pay 5% -.- 75% of regular L-.-component loads > 15MW and > 7000 full-.-load hours receive reduction of 50%., ***** Auto producers exempt for net own production consumers over 100 GWh/year pay reduced RES subsidies, beginning from >100GWh., ****** Reduced tariff for consumers with peak different from grid peak. Pumped hydro-.-storage exempt for 10 years if storage energy increased by 5%. Reductions for energy-.- intensive industries (>7000 full-.-load hours, >= 10GWh). Depending on full-.-load hours, tariff reduced TO 10, 15, or 20%.

## 5.3 Perspectives on financing network investment

At the European level, joint planning of the transmission network is promoted within the framework of the TYNDP and regional investment plans (see section 2.2). Merchant transmission investment, the inter-TSO compensation mechanism, and projects of common interest provide options for financing transmission projects or at least allocating some costs beyond the national transmission tariff scheme. While incentivising the transmission business for additional investors in the merchant case and ex-post allocation of network costs among TSOs has had limited success in increasing cross-border transmission capacity, the current trend with projects of common interests tends to ex-ante negotiations on cost allocation at a bilateral or multilateral level. The implications of each scheme are further elaborated below.

### 5.3.1 The case of merchant transmission investment

**Current developments do not indicate new merchant cables**

The so-called regulated approach in network investment is carried out by the TSO, and investment costs are recovered with a network tariff. However, European regulations 1228/2003 and 714/2009 provide yet another option: they lay down the basis for merchant interconnector investments undertaken by investors other than TSOs. Projects undertaken according to this scheme might be exempted from regulated third party access (i.e. with charges only in the case of congestion), restrictions to the use of congestion rents, tariff regulation and ownership unbundling. Still, every project has to be approved on a case-by-case basis by the national regulatory authority and the European Commission.

Cuomo and Glachant (2012) argue that while only four projects have received such an exemption, the EU has become more cautious in granting its approval. This reticence has increased uncertainty for merchant projects, which have witnessed regulatory changes during the final stage of approval. The first project – a 350 MW HVDC cable between Estonia and Finland (Estlink) – was accepted without conditions in 2005. Later projects – a 1 GW HVDC cable connecting the UK and Netherlands in 2007 (BritNed) and a 350 MW HVDC cable connecting the UK and Ireland in 2008 (East West Interconnector) – have had to concede to additional rules that set a cap on revenues and requirements for congestion management. In the case of the latest exemption – a 132 kV AC line between Austria and Italy (2010) – the European Commission even withdrew a national exemption from third party access. Gerbaulet and Weber (2014) have analysed the merchant case for possible additional investments in the Baltic Sea region.

With respect to Nordic-German integration, two projects for HVDC submarine cables between Norway and Germany have been developed in recent years: the Nord.LINK project as a regulated investment and the NorGer project according to the merchant scheme. As of late, the Nord.LINK project has been experiencing strong political support upon incorporation into the German national network development plan (Tennet, 2015), in consequence of which it was awarded the status of Project of Common Interest by the European Union (see next section) and the German government-owned development bank KfW contributed 50 percent to the financing of Germany's share of the investment. In February 2015, a final decision on its realisation was taken, and orders for construction were issued. Projected realisation is targeted for 2019/20. The realisation of the Nord.LINK project raises questions concerning the necessity of merchant exemptions for the more or less parallel NorGer project, and the regulatory scheme remains uncertain.

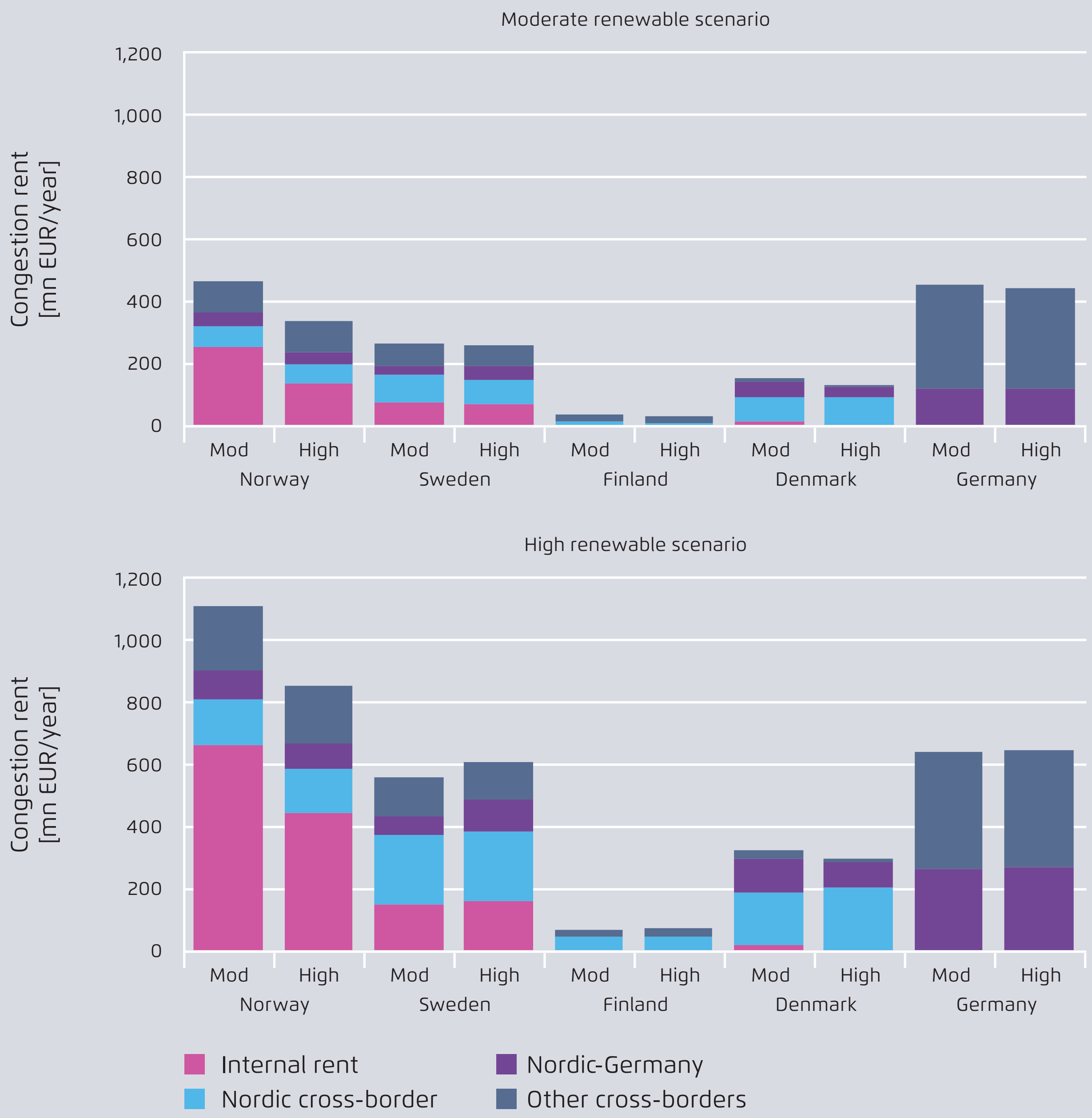
**The merchant case is possible between Norway/Sweden and Germany in the High Renewable scenario**

Our quantitative results provide indications concerning the congestion rents in the system and the effect of additional transmission capacity (Figure 12).

Regional development on the supply side has major implications for merchant investment incentives, illustrating their exposure to uncertainty in system and market development. By comparison, the scenario with high renewable deployment starts out with significantly higher conges-

Congestion rents for Moderate and High Transmission scenarios

Figure 12




Ea and DTU (2015) and own calculation

tion rents in the Moderate Transmission scenario. Most of the additional congestion rent occurs within Norway (+420 million EUR), between Norway, Sweden and Denmark (+280 million EUR) and between the Nordic countries and Germany (+300 million EUR). The values indicate that additional network expansion would be a reasonable way to integrate the higher levels of wind and hydro-power that are primarily located in Norway and Sweden.

In the High Transmission scenario, additional capacity is installed to connect Germany to Denmark and Sweden. While the congestion rents decrease between Denmark and Germany, indicating no case for additional merchant investment, it increases between Sweden and Germany by 50 percent as capacity doubles. For the connection between Norway and Germany, congestion rents are not sensitive to greater integration, given that no additional investment takes place between the two countries in the High Transmission scenario. The congestion rents on the Nord.LINK interconnector more than doubles from 43 to 92 million EUR per year between the moderate to High Renewable deployment scenarios.

#### 5.3.2 Inter-TSO compensation mechanism

One important step on the path towards the Internal Energy Market was the implementation of a non-discriminatory market-based solution for congestion management (Regulation (EU) 1228/2003). This allows third party access to network capacity and results in implicit transmission fees (congestion rents) between bidding zones only in the event of congestion and differences in zonal electricity prices (compare regulation for merchant investment). Prior to this, explicit auctions of cross-border capacity had been carried out without any sort of "use it or lose it" rule. While this former scheme allowed direct income for lines in the explicit auctions, it provided incentives for strategic bidding on capacity, which resulted in an inefficient use of cross-border capacity.

The regulation also introduced the inter-TSO compensation (ITC) mechanism, since cross-border trade could no longer be charged directly with market-based capacity allocation. The methodology of the ITC mechanism has been criticised as arbitrary and incapable of fulfilling its function. Daxhelet and Smeers (2005) argue that the calculation could end up producing nonsensical results by, on the one hand, inducing undue compensation to Member States responsible for transit and, on the other hand, by imposing excessive levies on others.

Regulations (EU) 714/2009 and 838/2010 specify the final method for collection and distribution of payments meant to compensate TSOs for making infrastructure available to host cross-border flows; these regulations also specify compensation for losses incurred in national transmission systems as a result of cross-border flows. Accordingly, contributions are calculated ex-post in proportion to net cross-border flows: the higher the absolute difference between imports and exports, the higher the contribution due. Compensation payments of an equal level are distributed for losses, these being based on a calculation with-and-without-transit costs and the costs of infrastructure using transit and load factors. The volume of the fund has been set at an initial level of 100 million EUR per year, which is rather low considering the total European infrastructure costs for the transmission network.

The regulation also requested the Agency for the Cooperation of Energy Regulators (ACER) to calculate the required volume to cover the forward-looking long-run average incremental costs of making cross-border infrastructure available. ACER (2013) published a recommendation on a new regulatory framework for ITC in which it suggests that the future approach should limit compensation to existing infrastructure. For new infrastructure, national regulatory authorities and ACER should engage in ex-ante cross-border cost allocation agreements for financing infrastructure with relevance for the EU. This development resulted in a cost-benefit analysis for investment projects and the definition of Projects of Common Interest, as described in the following section.

#### 5.3.3 Projects of Common Interest for trans-European energy infrastructure

Regulation (EU) 347/2013 on guidelines for trans-European energy infrastructure promotes the development of energy networks in priority corridors and areas. Projects of Common Interest (PCIs) are to be identified, and are to benefit from accelerated planning and permit granting procedures, sole national authority for obtaining permits, streamlined environmental assessment procedures, improved public participation, increased visibility as a PCI project, and the possibility of receiving financial support from Connecting Europe Facility (EU, 2015a). In the context of the European infrastructure package, Regulation (EU) 1316/2013 established the Connecting Europe Facility scheme to accelerate investment in the field of trans-European networks, endowing it with a financial support

Projects of Common Interest between the Nordics and Germany — Table 18

| Project of Common Interest/Cluster of PCIs | Description of PCI/s for country concerned |
|---|---|
| **Priority corridor: Electricity Northern Seas Offshore Grid** | |
| 1.3 Cluster Denmark-Germany between Endrup and Brunsbüttel including the following PCIs:<br>1.3.1 Interconnection between Endrup (DK) and Niebüll (DE)<br>1.3.2 Internal line between Brunsbüttel and Niebüll | 1.3.1 New 380 kV AC lines (OHL) of about 200 km and with 3000 MVA capacity in Germany and about 80 km in Denmark (onshore) and new transformers for integration of onshore wind in Schleswig-Holstein. |
| 1.4 Cluster Denmark-Germany between Kassø and Dollern including the following PCIs:<br>1.4.1 Interconnection between Kassø (DK) and Audorf (DE)<br>1.4.2 Internal line between Audorf and Hamburg/Nord (DE)<br>1.4.3 Internal line between Hamburg/Nord and Dollern (DE) | 1.4.1 Upgrade of existing 400 kV AC line and building a new 400 kV route in Denmark with a total length of 40 km.<br>1.4.2 New 400 kV AC double circuit line (OHL) mainly in the trace of an existing 220 kV line between Audorf and Hamburg/Nord, including 2 new 400/230 kV transformers in substation Audorf.<br>1.4.3 New 400 kV AC double circuit line (OHL) between Dollern and Hamburg/Nord, including 1 new 400/230 kV transformer in substation Hamburg/Nord and new 400 kV switchgear in Kummerfeld. The total length of German lines amounts to 195 km and a 4100 MVA capacity (onshore). |
| **Priority corridor: Electricity Baltic Energy Market Interconnection Plan** | |
| 1.8 PCI Germany-Norway interconnection between Wilster (DE) and Tonstad (NO) (currently known as the NORD.LINK project) | A new HVDC submarine cable of minimum 500 kV, approx imately 520–600 km and with a capacity of 1400 MW between Southern Norway and Northern Germany (onshore and offshore). |
| 4.1 PCI Denmark-Germany interconnection between Ishőj/Bjæverskov (DK) and Bentwisch/Güstrow (DE) via offshore windparks Kriegers Flak (DK) and Baltic 2 (DE) (currently known as Kriegers Flak Combined Grid Solution) | The Kriegers Flak Combined Grid Solution is the new off-shore multi-terminal connection between Denmark and Germany used for both grid connection of off-shore wind farms Kriegers Flak and interconnection.Exact technical features still have to be determined, but the project envisages 270 km of mainly offshoreand partially onshore HVDC cables with a voltage of ±320 kV and a capacity around 600 MW |

EC (2015b)

fund totalling €5.85 billion to be distributed between 2014 and 2020.

PCIs are determined every two years according to their contribution to the integration of national electricity systems and their system benefits, i.e. security of supply, competition and integration of renewable energies. The two priority corridors, *Electricity Northern Seas Offshore Grid* and *Electricity Baltic Energy Market Interconnection Plan*, are of relevance for the integration of the Nordic and German electricity systems. Currently four interconnection projects in the Nordic-German region involved in this study qualify as PCIs (Table 18).

Regulation (EU) 1316/2013 (35) states that "the costs for the development, construction, operation and maintenance of projects of common interest should in general be fully borne by the users of the infrastructure. Projects of common interest should be eligible for cross-border cost allocation when an assessment of market demand or of the expected effects on the tariffs has indicated that costs cannot be expected to be recovered by the tariffs paid by the infrastructure users."

In contrast with the inter-TSO compensation mechanism with ex-post cost allocation, the Connecting Europe Facility and Projects of Common Interest focus on the promotion of trans-European energy infrastructure. Accordingly, the responsibility for negotiations on financing and cost allocation is addressed at the bilateral level of TSOs and national regulatory authorities, with the possibility for cross-border cost allocation agreements for infrastructure of relevance to the EU. Considering the quantitative model results, the cross-border interconnectors in Denmark could be interesting candidates for cross-border cost allocation, given that they mainly provide benefits to neighbouring countries by providing additional transit capacity without creating benefits (e.g. congestion rents) for Denmark.

# 6 Market Integration of Cross-Border Transmission Capacity

## 6.1 Market integration with trading capacity of interconnectors

Geographically, the European electricity market is comprised of zonal bidding areas. Net transfer capacities (NTCs) between zones are implicitly auctioned in the spot market based on a common algorithm, which determines the lowest cost generation dispatch. Higher NTC capacity results in converging zonal prices as well as additional trade from the bidding zone with the higher price to the zone with the lower. In hours of full price convergence, the NTC constraint is not binding. NTC is the capacity available for commercial transactions, which aggregates the physical capacity of inter-zonal transmission lines.[14] It can be significantly lower than the sum of physical interconnectors and changes on an hourly basis due to security considerations and externalities in meshed AC networks. In meshed networks (e.g. in the Nordic system), the physical flow between two bidding zones can deviate from the market result due to the physical flow characteristics of electricity (e.g. loop flows).

The network between the Nordic region and Germany consists of point-to-point HVDC interconnectors and has no meshed elements. The NTC capacity in this case reflects a given individual interconnector, and physical flows closely follow the market results. However, hinterland integration in the AC network can impose constraints during certain hours (e.g. hours of high local wind generation in northern Germany), thereby reducing the available NTC capacity for the specific HVDC interconnector.

Today, most HVDC cables in the North and Baltic Seas region link Scandinavia (Norway, Sweden and Denmark-East) and continental Europe (Denmark-West, Germany, the Netherlands and Poland), which do not operate synchronously. The NTC in the spot market is close to the physical transmission capacity as long as the cable is operational and the hinterland integration into the AC network is sufficient. In 2014, non-available hours of DC cables ranked between 196 and 702 hours. The average market coupling capacity of the interconnectors Cross Channel, NorNed and Kontek has been almost 100 percent in hours of operation. The lower values for Skagerrak and Konti-Skan (78–90 percent) and especially for Baltic Cable (56–80 percent) could indicate a reduction of market capacity due to network limitations in the AC network. Also, values differ depending on the direction of trade flows (Table 19).

The common dispatch algorithm implicitly auctions available cable capacity in the zonal market, determining the congestion rent as an hourly trade flow multiplied by the zonal price difference between both ends of the cable. All submarine cables are point-to-point connections. They do not include meshed elements and link only two price zones. Interconnector capacity can also be reserved for other submarkets: the alternative utilisation of cable capacity might yield higher values (i.e. in reserve and capacity markets). As interconnector capacity and market integration increases, spot market prices converge and arbitrary values per MW exchange capacity decrease. Current projects for implementation are:

→ Skagerrak 4 cable (700 MW HVDC-VSC), starting test operation in late 2014, reserves 100 MW for secondary reserve (automatic FRR) from Norway to western Denmark. A model analysis on the reservation pattern showed a higher benefit than using this capacity in the spot market. The regulatory approval only lasts for one year. After the period of one year, a cost-benefit analysis must confirm the benefits. The current scheme only allows Norwegian producers to bid in the Danish market

14 TSOs calculate the NTCs according to methods approved by ENTSO-E. Usually the NTC consists of the total transfer capacity (TTC) considering network security minus a transmission reliability margin (TRM) to provide assistance to neighbouring zones if necessary (e.g. ELIA, 2015).

Historical market coupling data and elspot capacities for HVDC connections in 2014 — Table 19

| | | | NO2–DK1* | SE3–DK1 | DK1–DK2 | NO2–NL | SE4–DE | DK2–DE | DK1–DE |
|---|---|---|---|---|---|---|---|---|---|
| | | | Skagerrak | KontiSkan | Cross Channel | NorNed | Baltic Cable | Kontek | AC lines |
| **Maximum capacity** | → | MW | 1,000 | 680 | 590 | 700 | 615 | 585 | 1,700 |
| | ← | MW | 1,000 | 740 | 600 | 700 | 615 | 600 | 1,500 |
| **Minimum capacity** | → | MW | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | ← | MW | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Available capacity when operational** | → | % | 85.6 | 89.7 | 97.1 | 97.8 | 79.5 | 99.6 | 41.1 |
| | ← | % | 90.1 | 77.6 | 96.2 | 99.9 | 55.9 | 99.6 | 61.4 |
| **Time with zero capacity available** | → | h | 527 | 730 | 313 | 268 | 746 | 346 | 2,379 |
| | → | h | 527 | 813 | 313 | 268 | 521 | 346 | 191 |
| | ← → | h | 527 | 702 | 313 | 268 | 196 | 346 | 189 |

Nord Pool Spot (2015a); *Skagerrak 4 started operation on December 29, 2014. The maximum capacity increased to → 1432 MW / ← 1632 MW between NO2 and DK1.

but not the other way around. Still, the 100 MW have to be reserved in both directions (Energinet.dk, 2014).

→ Starting in 2015, neighbouring countries are eligible to participate in the capacity auctions for the year 2019/2020 in the United Kingdom (DECC, 2014). This ruling is considered important for the profitability of the planned interconnector between Norway and the United Kingdom (NSN Link).

## 6.2 Congestion management and regional pricing in the Internal Energy Market

The different scenarios in this report (section 3.1) illustrate and discuss distributional implications resulting from additional transmission infrastructure and system integration as well as regional developments in supply and demand. However, changes in congestion management also have distributional implications. In contrast with the primarily national price zones in continental Europe, most Scandinavian countries have implemented multiple bidding zones. Norway, with five zones, and Sweden, with four, address regional differences according to their north-south geography, and Denmark, with two zones, delineates its geographic separation into west and east (Nord Pool Spot, 2015b).

### Discussion on bidding zones in Germany

Today, Austria and Germany share a single joint price zone. The German *Energiewende*, i.e. the low carbon transformation, relies on wind and solar energy in the electricity sector. Capacity extension of these variable sources increases regional imbalances of hourly electricity supply and raises questions on future congestion management. Strong political support exists for the single price zone in Germany and Austria, as recently stated in the *Grünbuch – Green Paper* (BMWi, 2014). Frontier Economics and Consentec (2011) raise concerns about some issues related to the reconfiguration of existing bidding zones in the European market-coupling regime. The configuration of bidding zones must account for possible illiquidity and issues of market power in smaller zones. The possibility of a regular reassessment of bidding zones threatens a stable and predictable investment climate. Even though redefining price zones in Germany is not very urgent (Egerer et al., 2015 and Trepper et al., 2014), discussion of regional pricing could garner increased attention with rising wind power capacities in northern Germany and the scheduled nuclear phase-out by 2022 – two conditions threatening an increase in regional imbalances in supply and demand. The least cost market dispatch of the single bidding zone will require increasing levels of re-dispatch to be feasible in the physical transmission system, adding to the national cost of electricity.

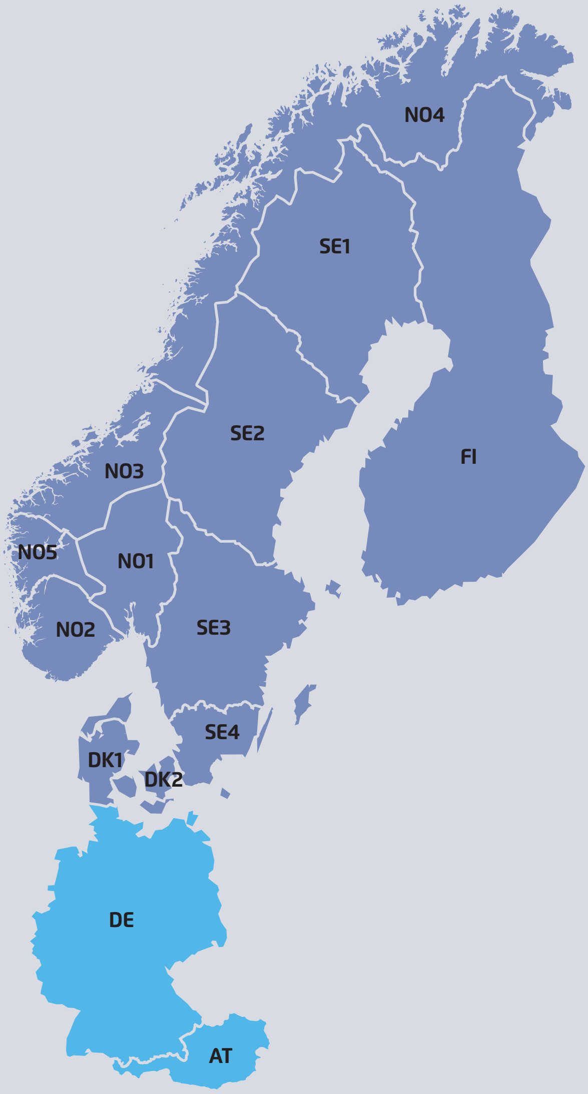
An open discourse on the operational challenges of high-renewable electricity systems could also focus on broader options for a) today's bid-based markets by reconsidering the borders of bidding zones, as compared to b) a centralised dispatch by an independent system operator (ISO) applying a nodal pricing scheme for efficient congestion management (Hogan, 1992, 1999, PJM, 2015). At the European level, the current draft version on the new "Capacity Allocation and Congestion Management" (CACM) regulation points towards a review of bidding zones, remaining in the zonal framework for now; this regulation defines network security, overall market efficiency, as well as market stability and robustness as criteria for reviewing the bidding zone configuration (EC, 2015c).

Alternative bidding zone configurations could end the joint German-Austrian zone and define additional zones within Germany. Several zonal shapes for Germany are being considered (Figure 13): for example, i) two zones, one northern and one southern (Bettzüge, 2014), ii) three zones, with two in the north (Breuer and Moser, 2014) which could also include parts of neighbouring countries like western Denmark, and iii) four zones, with one eastern zone joined to parts of Poland (Supponen, 2011).

While many factors are relevant to the decision concerning spatial market aggregation, the distributional impacts to market participants are of particular importance in considering a move from one scheme to another (Löschel et al., 2013; ACER, 2013).

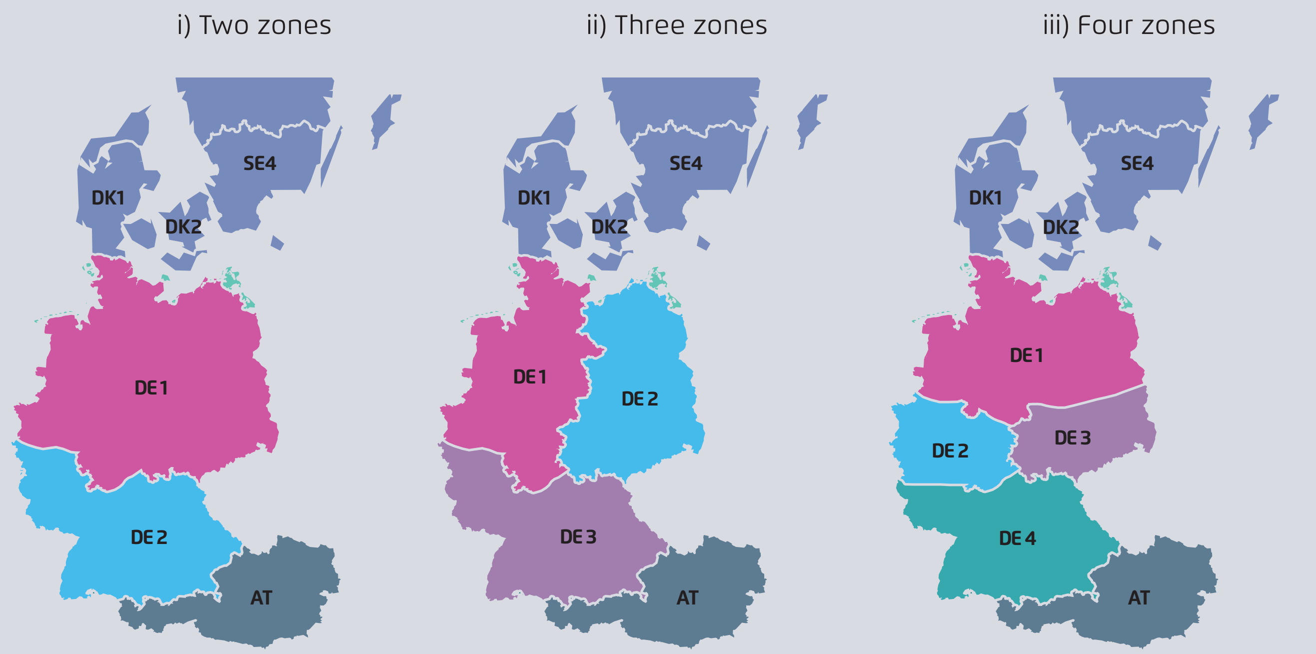
Today's bidding zone configuration with a joint single zone for Germany and Austria

Figure 13




Own illustration

Possible alternative bidding zone configurations for Germany — Figure 14




Own illustration

**Relevance of price zones in the context of this study**

The quantitative analysis of this project (Work Package 1) assumes a stable definition of bidding zones for the time horizon of this study. Quantifying the effects of bidding zones on the integration of the Nordic and German electricity systems is very challenging. First, a decision must be reached on the specific scenario (e.g. options differing from Figure 13) and on the value of inter-zonal NTC capacities between additional zones. In addition, many parameters affect the implications of additional bidding zones:

- → the time-line of transmission enforcement of north-south lines within Germany is uncertain;
- → inter-zonal NTC capacities in meshed AC grids vary on an hourly basis due to the changing network situation with variable zonal wind generation and demand;
- → zonal electricity prices would deviate between the German bidding zones in the event of limited inter-zonal NTC capacity; and
- → trade flows to Scandinavia and all other neighbouring countries change as a result of different price/scarcity signals at the zonal border.

Other studies provide estimates for price differentials between two German bidding zones and the implications these may have for neighbouring countries (Thema, 2013) as well as discuss the implications for Germany and neighbouring electricity systems (ČEPS et al., 2012).

Additional bidding zones and their geographic scope in northern Germany would have strong effects on the market outcome and on the evaluation of Nordic-German integration. One can think of the northern German bidding zone(s) as region(s) with comparably low demand and large supply surplus in hours of high wind generation located between the Nordic region and the large consumption centres of central Europe. Abstracting from many other parameters, the available interconnector capacity between the Nordic region and Germany and the supply-demand balance in the Nordic countries remain important factors. Now, however, the frequency and intensity of trade constraints between the bidding zones within Germany will, among other factors, have an impact on results. In the following, it is assumed that the northern bidding zone(s) experiences constraints when exporting to the southern German bidding zone(s) in hours of high wind generation. In such a setting, the smaller bidding zone(s) in northern Germany will see more hours with zonal surplus in wind generation, resulting in a price pattern with more hours of lower zonal prices but no additional price spikes. Prices in northern Germany are unlikely to increase significantly in hours of low wind generation due to the low zonal load shares and also due to substantial capacity in offshore wind generation with more uniform generation patterns.

This change in the price pattern provides incentives for additional exports to Norway and Sweden. Due to the lower prices when importing from the northern price zone in Germany during times of high wind feed-in, it is primarily the Nordic consumers who could benefit.

However, the evaluation of these effects depends on the perspective taken. This is particularly important for Nordic electricity producers who may be exposed to market effects of a possible northern bidding zone in Germany. If interconnector capacity between the Nordic and German systems is rather high, flexible producers in Norway and Sweden (i.e. hydro-reservoirs) can reallocate their generation to hours with lower wind output. During these hours, inter-zonal trade capacity would be sufficient, and prices in the northern bidding zone should converge with the prices of other neighbouring bidding zones (e.g. with those in southern Germany). Producers would be able to collect benefits similar to those collected when there was a single German bidding zone. Generation technologies with stable and inflexible generation output (e.g. nuclear power in Sweden) could be more vulnerable to the northern bidding zone, since the value of their generation output would decrease in hours of high wind generation.

In the case of rather low interconnector capacity between northern Germany and Scandinavia, even the flexible generation technologies in the Nordic region would find themselves more exposed to hours with low electricity prices as they face the limiting export constraint when trying to reallocate generation output. The overall effects increase in the event of additional renewable deployment in the Nordic region, since additional cross-border transmission capacity is required for exports to Germany. Following this line of argument, splitting the single price zone in Germany into at least a northern and southern bidding zone would alter the incentives for integration between the Nordic region and Germany for different stakeholder groups. The central results of this report – which aims to highlight the positive effects of system integration between the Nordic region and Germany alongside the challenges of distributional effects – continue to hold true and may even become more pronounced with additional price zones and regional price signals within Germany.

# 7 Conclusion

The North and Baltic Seas region – in this study the Nordic region (Norway, Sweden, Finland and Denmark) and Germany – is of particular interest for European electricity market integration and the transformation towards a low carbon electricity sector. Complementarities between supply technologies and demand patterns offer opportunities to exploit synergies that would promote socioeconomic welfare. Physically, additional submarine transmission cables would strengthen the integration of the Nordic and German electricity systems. Commercially, trade flows would increase in both directions: under largely stable conventional capacity and with high renewable deployment in the Nordic region, most cross-border transmission capacity would be required for exports to Germany. This market integration would trigger price convergence between the Nordic region and Germany, resulting in distributional effects. Wholesale electricity prices would increase in the Nordic region, and Germany would see a small decline in prices. Concretely, the average price spreads would decrease from 10 to 7 EUR/MWh under the Moderate Renewable scenario and from 26 to 20 EUR/MWh under the High Renewable scenario.

Generally, benefits that can be identified from the model calculations are positive from an overall system perspective. Specifically, all countries see an increase in national rents, with the exception of Denmark. The extent of benefit depends on the underlying scenario assumptions, however. This asymmetric allocation of costs and benefits could hamper the regional development of the electricity system. At the same time, costs for cross-border network investments would accrue, which have to be distributed among countries. Likewise, additional hinterland network integration may be necessary to accommodate the new trade opportunities, but may at the same time serve national targets by harmonising changing spatial supply and demand patterns. A prudent design of cross-border allocation schemes could mitigate opposition and provide national strategic incentives that otherwise might be lacking. Integration does not only have distributional impacts between countries, but also between stakeholders: price convergence creates winners and losers among consumers and producers, with effects several times higher than that for national costs and benefits. In Norway, Sweden and Finland, additional integration shifts about 300-400 million EUR/year in each country from consumers to producers. In the High Renewable scenario, levels in Norway increase to 900 million EUR/year while they remain equal in Sweden and decrease in Finland.

Being a particularly sensitive consumer group, the energy-intensive industries in the Nordic region have historically benefited from low electricity prices. Wholesale electricity prices in the Nordic region would decrease with renewable deployment and weak interconnection and increase with integration. The current price composition supports energy-intensive industry: firms pay an energy component that only covers a small share of system costs, and they are mostly exempt from other charges, which are then socialised to other consumers. However, some mitigation options exist that would enable firms to adapt to price changes. From a macro-economic perspective, the energy-intensive industries do not carry the same weight in terms of employment and turnover compared to their electricity consumption.

All in all, the integration of the Nordic and German electricity systems supports European policy goals in the electricity sector (i.e. the internal energy market and the low carbon transformation). Integration of the electricity systems is an ongoing process that is supported by the steady increase in physical exchange capacity and the harmonisation of market designs. In any case, both the Nordic countries, with their strong reliance on hydro-power, and Germany, with its *Energiewende*, would benefit from increased integration by gaining flexibility to balance higher renewable shares and from increased security of supply.

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# Economic and Climate Effects of Increased Integration of the Nordic and German Electricity Systems

Data Report to Work Package 1

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# 1 RES-E deployment

**Main assumptions**
Table 1 describes the overall assumptions regarding the deployment of renewable energy in the core countries for the 2030 scenarios and the common assumptions on development through 2020.

For the five core countries, the detailed assumptions are described below in terms of potential generation from RES-E. The corresponding capacities are summed up in section 1.6. Note that the ratio between capacity and generation can vary from source due to different assumptions about the underlying resource (e.g. wind speed) in the model.

For neighbouring countries, which are not part of the core analysis, National Renewable Energy Action Plans (NREAPs) are used to define the development through 2020. After 2020 a common level of subsidies for RES-E of 15 €/MWh is used to estimate investments in renewable energy capacity.

## 1.1 Denmark

**Moderate RE**
The figure below (Figure 1) shows RES-E development in Denmark based on information by the Danish transmission system operator (TSO) Energinet.dk for the Moderate RE scenarios.[1] The values are shown for 2030. For 2035, the assumptions by Energinet.dk are a little lower than the wind scenario developed by the Danish Energy Agency.[2] However, the 2030 values can be a valid development towards the Danish Energy Agency's numbers for 2035. The Danish Energy Agency projects 8.5 GW of wind for

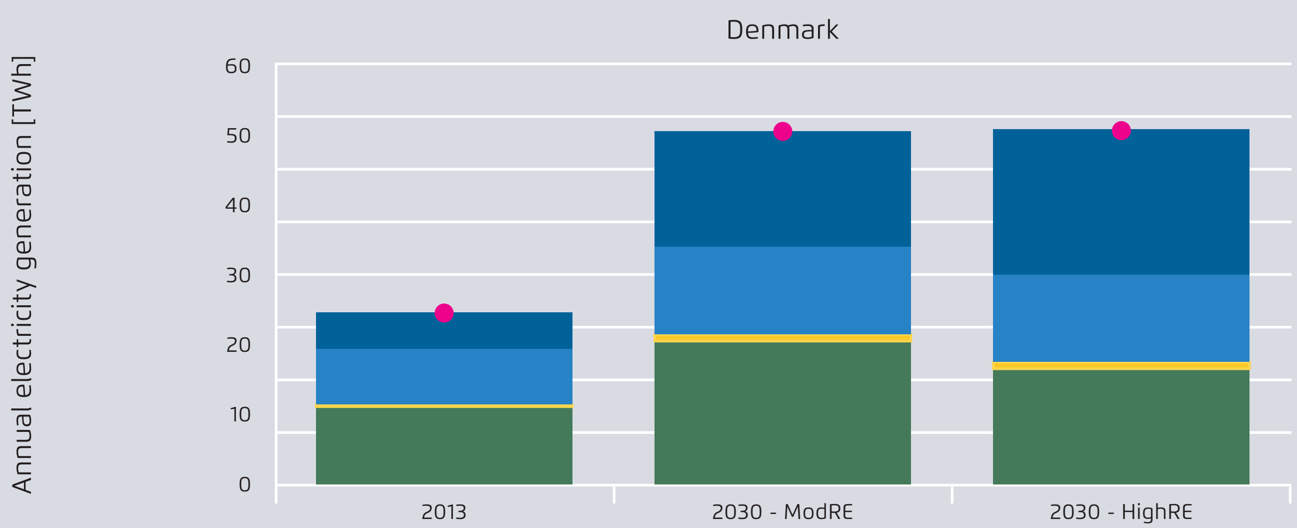
Sources for the RES-E scenario setup — Table 1

| | 2020 | 2030 High RE | 2030 Moderate RE |
|---|---|---|---|
| Germany | Projection based on the Renewable Energy Act (EEG) | Vision 4 of ENTSO-E TYNDP 2014 | Scenario B of 1st draft of NEP scenario framework 2015 |
| Denmark | National targets exceeding NREAP:<br>- 50 % wind target<br>- coal to biomass conversion | Hydrogen Scenario by Danish Energy Agency | Danish TSO Energinet.dk's plans, Danish Energy Agency |
| Sweden | National Renewable Energy Action Plan | Swedish Energy Agency's Checkpoint 2015 Report and a higher RE ambition | Swedish Energy Agency's Checkpoint 2015 Report |
| Norway | National Renewable Energy Action Plan | Vision 4 of ENTSO-E TYNDP 2014 | Vision 3 of ENTSO-E TYNDP 2014 |
| Finland | National Renewable Energy Action Plan | Vision 4 of ENTSO-E TYNDP 2014 and VTT Low Carbon Finland 2050 | Vision 3 of ENTSO-E TYNDP 2014 and VTT Low Carbon Finland 2050 |

See the main report for further details

2035 og 2050

Assumptions for RES-E generation in Denmark. Values shown for biomass result from the model simulations. Figure 1




| | 2013 | 2030 - ModRE | 2030 - HighRE |
|---|---|---|---|
| Offshore wind | 5 | 15 | 20 |
| Onshore wind | 7 | 12 | 12 |
| Solar | 0 | 1 | 1 |
| Biomass | 10 | 19 | 16 |
| Hydro | 0 | 0 | 0 |
| Total RE | 22 | 48 | 48 |

Own illustration

2035, while Energinet.dk assumes 8.1 GW. The Danish Energy Agency also assumes a higher share of offshore wind power, which contributes to higher wind production relative to Energinet.dk.

The development for wind and solar power is defined exogenously in terms of installed capacity and expected number of full load hours.

For biomass, the conversion of existing large central power plants from coal or gas to biomass is based on the most recent available information from stakeholders. For three larger power plants, conversion plans are uncertain, and modelled as an endogenous investment option (central power plants in Esbjerg, Odense and Aalborg).

The development of a new centralised or decentralised biomass- and biogas-fired CHP is based on endogenous investment decisions, driven by existing tax- and subsidy schemes.

For historical reasons, the model representation for Denmark is more detailed than those for other countries. This is also true for energy policies, which is why existing tax and subsidy-schemes for heat and electricity production in Denmark is represented in the model.

**High RE**

The high RES-E deployment for Denmark emerged from the hydrogen scenario developed by the Danish Energy Agency. This scenario is based on a higher amount of wind power and electricity use for hydrogen production, as well as on lower biomass usage relative to the wind scenario (which is in line with the moderate RES-E scenario). However, since this project does not analyse energy use in other sectors, only increased wind power deployment from the hydrogen scenario is considered here. By 2035 the Danish Energy Agency will assume an additional 1 GW of offshore wind power. We have applied this value here for 2030.

## 1.2 Finland

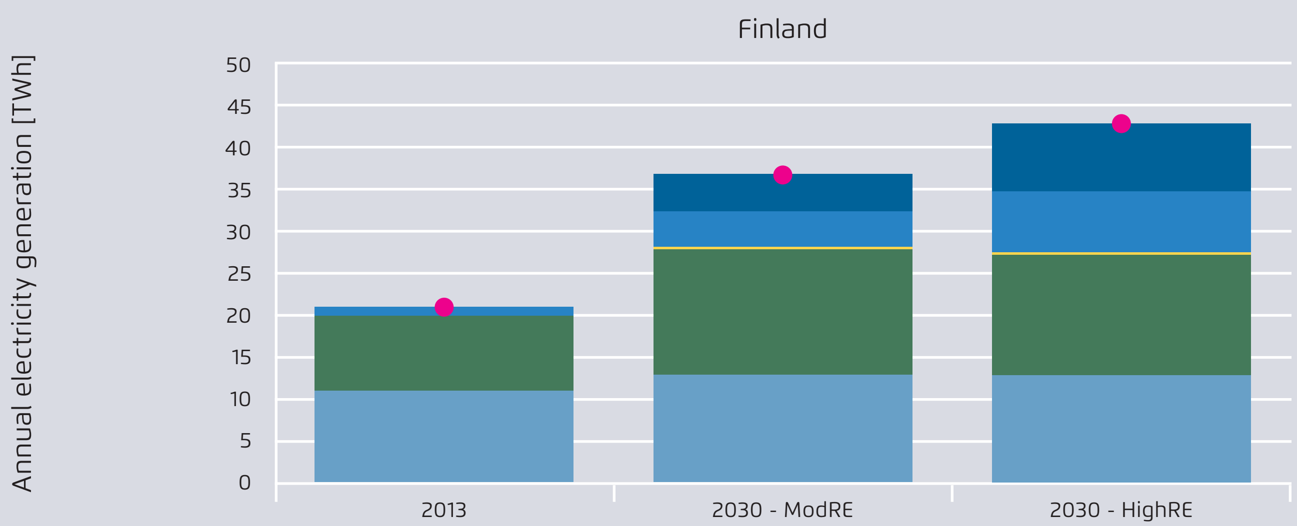
**Moderate RE**

The Finnish national target for wind power is a 20 percent share of total electricity demand. This means that the installed capacity of wind turbines will be approximately 2.5 GW with a generation of 6 TWh.

The two scenarios (Moderate and High RES-E) draw from the VTT report "Low Carbon Finland 2050"[3], where three different scenarios are examined. The first one, "Tonni", is driven by growing energy demand and cost efficiency. For this scenario, the technological development is conservative with some investments in RES-E and the introduction of carbon capture. The second scenario, "Inno", assumes fast technological development, with investments in CHP plants, renewable energy technologies and carbon capture. The last scenario, "Onni", presents significant changes in industrial structure in which production becomes less energy intensive, while investments are made in distributed energy production based on renewable energy. Numbers are not included in the report, so the assumptions are based on the graphs provided.

For the moderate RE scenario, the estimates for wind power are based on the three scenarios for 2030. These scenarios operate with the same level of generation – approx. 8 TWh, or roughly 3.4 GW – which is slightly more than the national target for 2020 in Finland (2.5 GW).

Assumptions for RES-E generation in Finland. Figure 2




| | 2013 | 2030 - ModRE | 2030 - HighRE |
|---|---|---|---|
| Offshore wind | 0 | 4 | 8 |
| Onshore wind | 1 | 4 | 7 |
| Solar | 0 | 0 | 0 |
| Biomass | 9 | 15 | 14 |
| Hydro | 11 | 13 | 13 |
| Total RE | 22 | 37 | 43 |

Own illustration

**High RE**

To express a situation with higher RES-E deployment in the High RES-E scenario, we apply the wind power generation value from the 2040 Inno scenario. In this case wind generation is 14 TWh, or roughly 5.9 GW of onshore capacity.

In both cases, the deployment of other renewable energy technologies is based on the Vision 3 assumption of the TYNDP 2014. This amounts to 1.2 GW of additional biomass-fired capacity relative to 2014 and a small increase in the generation of hydro power.

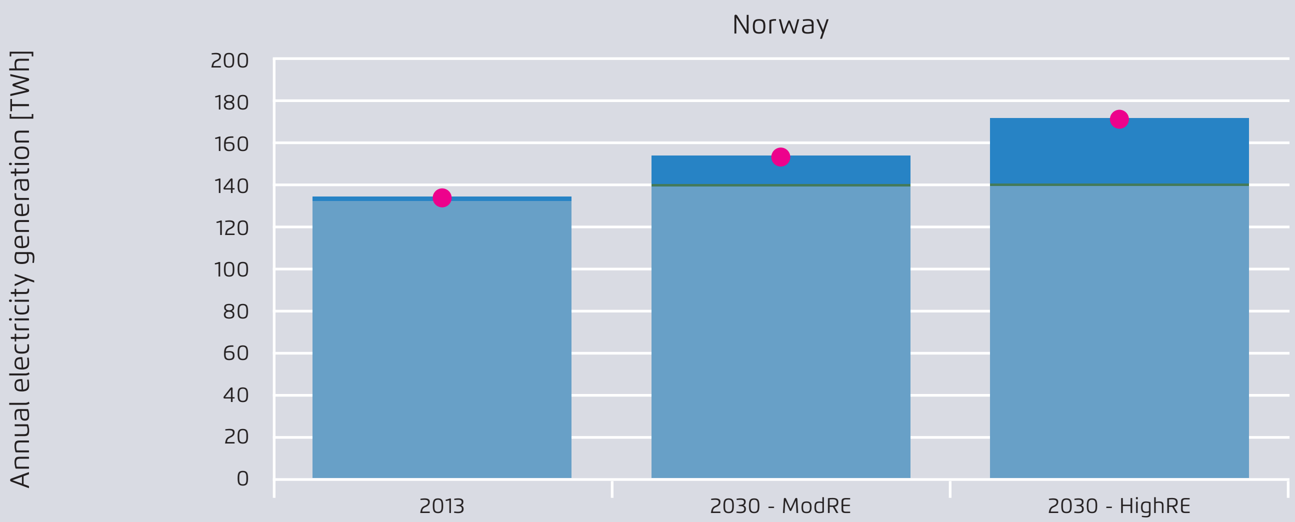
**Nuclear capacity**

Finland plans to further expand its nuclear capacity. The new Olkiluoto 3-reactor has been delayed a number of years, and is now projected to go into operation by 2018. Two older units are expected to be decommissioned in 2027 and 2030 (Loviisa 1 and 2, with a total of 1 GW). Furthermore, two additional nuclear power plants, with a total capacity of approximately 2.4 GW (Olkiluoto 4 and Fennovoima Hanhikivi 1), are expected to open between 2020 and 2030.

The moderate scenario assumes that the Olkiluoto 3 reactor will be in operation and that two new nuclear power plants will be commissioned. It puts the total nuclear power capacity at 5.7 GW by 2030.

The High RE scenario projects an operational Olkiluoto 3 reactor, but only one new nuclear power plant thereafter, with a capacity of 1.2 GW. In this scenario, investments in wind power capacity replace nuclear power capacity. The total nuclear capacity is expected to be 4.5 GW by 2030.

Assumptions for RES-E generation in Norway. Figure 3




| | 2013 | 2030 - ModRE | 2030 - HighRE |
|---|---|---|---|
| Offshore wind | 0 | 0 | 0 |
| Onshore wind | 2 | 14 | 32 |
| Solar | 0 | 0 | 0 |
| Biomass | 0 | 1 | 1 |
| Hydro | 131 | 139 | 139 |
| Total RE | 134 | 154 | 172 |

Own illustration

## 1.3 Norway

**Moderate RE**

Figure 3 shows the assumptions for RES-E in Norway based on Vision 3 and Vision 4 from the ENTSO-E TYNDP report.

**High RE**

In the High RES-E scenarios, 6.4 GW more of offshore wind is deployed than in the Moderate RES-E scenarios. Hydro power capacity remains the same and no additional pump station capacity is assumed.

## 1.4 Sweden

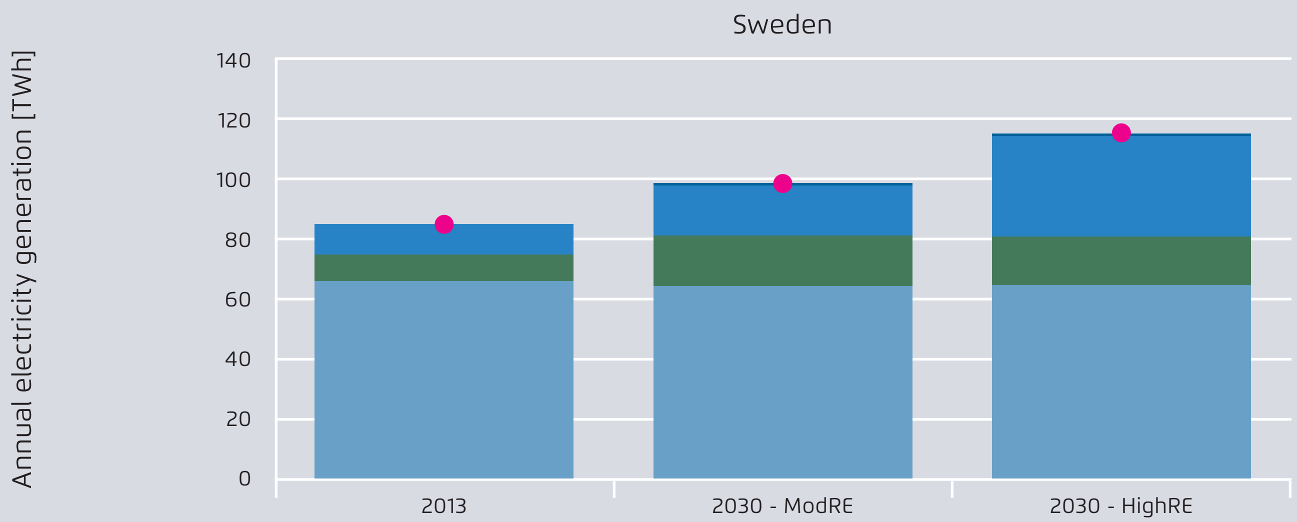
**Moderate RE**

The development in the Moderate RES-E scenario is based on information in the Swedish Energy Agency's Check-point 2015 report, published by the Energy Agency on October 1st. It is considered the best and most accurate official material available and is in line with the Swedish Radiation Safety Authority on upgrading safety measures.

Starting in 2017, the ten existing nuclear reactors in Sweden will be subject to tighter safety regulations for cooling in emergency situations. It is assumed that three reactors will be closed between 2020 and 2030 after 50 years of operation. The seven remaining reactors are expected to be upgraded and remain in operation after 2030. The total nuclear capacity is projected to be 10.1 GW by 2020, with an estimated production of 76.3 TWh; by 2030 it will drop to 7.9 GW, with an estimated production of 56.8 TWh.

In the moderate RES-E scenario hydro power generation increases only slightly relative to today's levels, while wind power capacity increases to more than 7 GW.

Assumptions for RES-E generation in Sweden. Figure 4




| | 2013 | 2030 - ModRE | 2030 - HighRE |
|---|---|---|---|
| Offshore wind | 0 | 0 | 1 |
| Onshore wind | 10 | 17 | 33 |
| Solar | 0 | 0 | 0 |
| Biomass | 9 | 17 | 17 |
| Hydro | 66 | 64 | 64 |
| Total RE | 85 | 98 | 115 |

Own illustration

### High RE

The High RES-E deployment scenario is also based on projections from the Swedish Energy Agency's Checkpoint 2015 report. The High RES-E scenarios operate on a higher set of ambitions for RES-E in Sweden through 2030. The additional volume of renewables in the High RES-E scenarios comes from wind energy only. The total effect is a doubling of wind power capacity by 2030 relative to the Moderate scenarios, from 7.1 GW with a production of 17 TWh to 14.2 GW with a production of 34 TWh. The majority of additional wind power is expected to be onshore. Assumptions about the deployment of other RES-E and the development of nuclear power are the same as in the moderate RES-E scenarios.

## 1.5 Germany

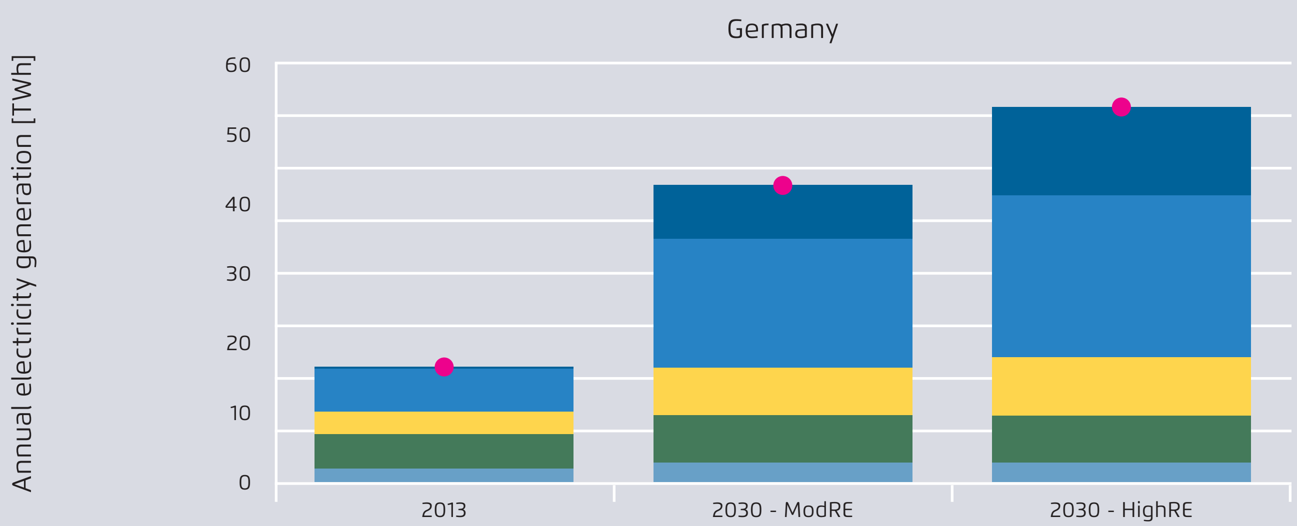
### Moderate RE

As stipulated by the Renewable Energy Act from August 2014, Germany plans to expand RES-E to 55–60 percent of total electricity demand by 2035.[4] The Moderate RE scenarios for Germany are based on the targets defined in the German Renewable Energy Act. The scenario framework (draft) for the German grid development plan (NEP), published by the German TSOs in April 2014, has been used to interpret the law and estimate capacities. Further details of RES-E development are described in appendix E. The resulting assumptions for generation from RES-E are illustrated in figure 5.

### High RE

For the High RES-E scenario a more ambitious deployment was selected based on vision 4 of the TYNDP. For biomass,

Assumptions for RES-E generation in Germany. Figure 5




| | 2013 | 2030 - ModRE | 2030 - HighRE |
|---|---|---|---|
| Offshore wind | 2 | 59 | 95 |
| Onshore wind | 59 | 141 | 178 |
| Solar | 32 | 52 | 63 |
| Biomass | 46 | 53 | 53 |
| Hydro | 19 | 20 | 20 |
| Total RE | 158 | 325 | 409 |

Own illustration

the assumptions of the Medium RE scenario are maintained, as wind and PV remain the pillars of renewable energy transition in Germany's energy policy. No additional hydro pump station capacity is included.

## 1.6 Capacities for RES-E

The capacities for RES-E that match the above generation levels are summed up in table 2.

Capacities for RES-E in different scenarios — Table 2

| | Onshore Wind | Offshore Wind | Solar | Biomass | Biogas | Hydro | Total |
|---|---|---|---|---|---|---|---|
| **Denmark** | | | | | | | |
| 2013 | 3,441 | 1,170 | 232 | 919 | 64 | | 5,826 |
| 2020 | 3,773 | 2,272 | 630 | 3,221 | 46 | | 9,942 |
| 2030 | | | | | | | |
| Moderate RE | 4,023 | 3,772 | 1,138* | 4,279 | 9 | | 13,221 |
| High RE | 4,023 | 4,772 | 1,138* | 3,998 | 9 | | 13,940 |
| **Finland** | | | | | | | |
| 2013 | 448 | | | 1,921 | 19 | 3,140 | 5,528 |
| 2020 | 1,633 | 867 | 10 | 1,498 | 19 | 3,181 | 7,208 |
| 2030 | | | | | | | |
| Moderate RE | 2,177 | 1,173 | 40 | 1,826 | 19 | 3,634 | 8,869 |
| High RE | 3,777 | 2,073 | 40 | 1,826 | 19 | 3,634 | 11,372 |
| **Norway** | | | | | | | |
| 2013 | 811 | | | | | 30,960 | 31,771 |
| 2020 | 3,535 | | | 119 | | 31,780 | 35,434 |
| 2030 | | | | | | | |
| Moderate RE | 5,000 | | | 155 | | 32,772 | 37,927 |
| High RE | 11,400 | | | 163 | | 32,772 | 44,335 |
| **Sweden** | | | | | | | |
| 2013 | 4,470 | | 43 | 2,686 | | 16,150 | 23,349 |
| 2020 | 4,898 | 5 | 44 | 3,448 | | 16,461 | 24,856 |
| 2030 | | | | | | | |
| Moderate RE | 7,115 | 5 | 50 | 3,618 | | 16,461 | 27,249 |
| High RE | 14,020 | 220 | 50 | 3,583 | | 16,461 | 34,334 |
| **Germany** | | | | | | | |
| 2013 | 33,209 | 521 | 35,099 | 2,578 | 4,286 | 4,629 | 80,322 |
| 2020 | 44,242 | 6,222 | 51,048 | 610 | 6,751 | 4,795 | 113,669 |
| 2030 | | | | | | | |
| Moderate RE | 65,795 | 13,581 | 57,948 | 806 | 7,056 | 5,036 | 150,222 |
| High RE | 84,493 | 21,756 | 69,763 | 1,071 | 7,164 | 5,054 | 189,300 |

Exact numbers can differ from source due, say, to different assumptions about the RE resource (such as wind speed).
*Capacity for solar power is approximately 300 MW below the official assumptions of Energinet.dk.

# 2 Transmission system

The transmission system as of 2013 is shown in Figure 8. Additional projects beyond the existing system are shown in the table below for the two grid expansion scenarios (ModTrans and HighTrans). All capacities in the ModTrans scenarios extend beyond those of 2013; all capacities in the HighTrans scenarios extend beyond those of the ModTrans scenarios.

Moderate integration of grids

Table 3

| Project | From | To | Capacity (MW) | Year | Estimated cost (M €) | Estimated cost (M €/MW) |
|---|---|---|---|---|---|---|
| **Connections between Core Countries** | | | | | | |
| Skagerrak IV | DK_W | NO_SW | 700 | 2015 | – | – |
| NordLink Cable | NO_SW | DE_NW | 1,400 | 2018 | 2,500 | 1.79 |
| West Denmark to Germany | DK_W | DE_NW | 720 | 2019 | 220–270 | 0.22–0.27 |
| | DE_NW | DK_W | 1,000 | | | |
| Kriegers Flak | DK_E | DK_KF | 600 | 2019 | 300 | 0.21 |
| | DE_NE | DE_KF | 400 | | | |
| **Internal Reinforcements** | | | | | | |
| Sydvastlanken | SE_M | SE_S | 1,200 | 2016 | – | – |
| RES/SoS Norway/Sweden phase 1 | SE_M | SE_N2 | 700 | 2019 | 560–930 | 0.37–0.62 |
| | NO_M | NO_MW | 1,500 | 2020 | | |
| Nordlink cable | NO_MW | NO_SW | 1,000 | 2020 | | |
| **Connections to Third Countries** | | | | | | |
| NordBalt Cable Phase 1 | SE_S | LT_R | 700 | 2015 | 690–1,200 | 0.99–1.71 |
| LitPol Link Stage 1 | PL_R | LT_R | 0 | 2015 | 510 | 1.02 |
| | LT_R | PL_R | 500 | | | |
| Doetinchem-Niederrhein***** | NL_R | DE_CS | 2,800 | 2016 | 190–220 | 0.07–0.08 |
| ElexLink | GB_R | FR_R | 1,000 | 2016 | 260–440 | 0.26–0.44 |
| GerPol Improvements | PL_R | DE_ME | 1,500 | 2017 | 150 | 0.1 |
| | DE_ME | PL_R | 500 | | | |
| Luxembourg–Belgium Interco | BE_R | LX_R | 700 | 2017 | 150–170 | 0.21–0.24 |
| Nemo* | BE_R | GB_R | 700 | 2018 | 600–700 | 0.86–1 |
| Greenconnector | CH_R | IT_R | 800 | 2018 | – | 0 |
| Cobra Cable | DK_W | NL_R | 700 | 2019 | 560–680 | 0.8–0.97 |
| ALEGRO | BE_R | DE_CS | 1,000 | 2019 | 450–570 | 0.45–0.57 |
| Italy–France | FR_R | IT_R | 1,200 | 2019 | 1,100–1,300 | 0.92–1.08 |
| | IT_R | FR_R | 1,000 | | | |
| LitPol Link Stage 2 | PL_R | LT_R | 1,000 | 2020 | 310 | 0.31 |
| | LT_R | PL_R | 500 | | | |
| Estonia–Latvia | EE_R | LV_R | 500 | 2020 | 105–195 | 0.21–0.39 |

Moderate integration of grids

Table 3

| Project | From | To | Capacity (MW) | Year | Estimated cost (M €) | Estimated cost (M €/MW) |
|---|---|---|---|---|---|---|
| Norway–Great Britain | NO_SW | GB_R | 1,400 | 2020 | 1,700 | 1.21 |
| Austria-Germany | AT_R | DE_CS | 2,900 | 2020 | 830–1,400 | 0.29–0.48 |
| Belgian North Border | NL_R | BE_R | 1,500 | 2020 | 350–450 | 0.23–0.3 |
| IFA2 | GB_R | FR_R | 1,000 | 2020 | 540–830 | 0.54–0.83 |
| Lake Geneva West | FR_R | CH_R | 500 | 2020 | 8–12 | 0.02–0.02 |
| | CH_R | FR_R | 200 | | | |
| France–Belgium** | BE_R | FR_R | 1,400 | 2021 | 110–170 | 0.08–0.12 |
| GerPol Power Bridge | PL_R | DE_ME | 500 | 2022 | 390–400 | 0.26–0.27 |
| | DE_ME | PL_R | 1,500 | | | |
| St. Peter-Pleinting | AT_R | DE_CS | 1,500 | 2022 | 130–190 | 0.09–0.13 |
| Area of Lake Constance**** | CH_R | DE_CS | 1,400 | 2022 | 390–530 | 0.11–0.16 |
| | DE_CS | CH_R | 8,800 | | | |
| France-Alderney-Britain*** | GB_R | FR_R | 1,400 | 2022 | 470–1,100 | 0.36–0.85 |
| Italy–Switzerland | IT_R | CH_R | 950 | 2022 | 1.080 | 1.08 |
| | CH_R | IT_R | 1,000 | | | |
| Italy–Austria | AT_R | CH_R | 1,450 | 2023 | 780–1,180 | 0.54–0.81 |
| | CH_R | AT_R | 1,350 | | | |
| Lake Geneva South | FR_R | CH_R | 1,000 | 2025 | 110–140 | 0.07–0.09 |
| | CH_R | FR_R | 1,500 | | | |
| Dutch Ring | NL_R | DE_NW | 500 | 2025 | 1,800–3,100 | 3.6–6.2 |
| Hansa PowerBridge****** | SE_M | LV_R | 600 | 2030 | | |

Own illustration; Interconnections constitute the moderate integration of grids scenario, together with net transfer capacities and their respective costs. They are divided into projects among core countries, internal reinforcements to be commissioned by 2020 and projects among third countries to be commissioned by 2025. All are based on the TYNDP. Minor deviations from the TYNDP 2014 (stated cost are based on TYNDP capacities): *Additional trade capacity in the model slightly below the TYNDP 2014 (1000 MW projected)., **Additional trade capacity from BE to FR in the model slightly above TYNDP 2014 (1,300 MW projected). Additional trade capacity from FR to BE in the model at 2,500 MW, which is above TYNDP 2014 (1,300 MW projected)., ***Additional trade capacity in the model slightly below TYNDP 2014 (1,400 MW projected)., ****Additional trade capacity in the model from DE to CH increased by 8,800 instead of the 3,400 projected in TYNDP 2014., *****Additional trade capacity in the model above TYNDP 2014 (1,400 MW projected)., ******A new transmission line between Sweden and Latvia is included in the calculations. This project is mentioned as a possible alternative to the Hansa PowerBridge project between Sweden and Germany. It should not have been included in the calculations, as the project is not supposed to be implemented in parallel with the Hansa PowerBridge between Germany and Sweden.

High integration of grids — Table 4

| Project | From | To | Capacity (MW) | Year | Estimated cost (M €) | Estimated cost (M €/MW) |
|---|---|---|---|---|---|---|
| **Core Countries (Additional Projects)** | | | | | | |
| Westcoast | DK_W | DE_NW | 500 | 2022 | 170–210 | 0.34–0.42 |
| Hansa PowerBridge | SE_S | DE_NE | 700 | 2025 | 200–400 | 0.29–0.57 |
| 3rd AC Finland-Sweden | SE_N1 | FI_R | 1,000 | 2025 | 64–120 | 0.06–0.12 |
| Finland-Norway | NO_N | FI_R | 500 | 2030 | 300–700 | 0.6–1.4 |
| Norway-North Sweden | NO_M | SE_N2 | 750 | 2030 | 140–330 | 0.19–0.44 |
| East Denmark-Germany | DK_E | DE_NE | 600 | 2030 | 500–610 | 0.83–1.02 |
| **Sum of additional costs** | | | | | **1,374–2,370** | |
| **Internal Reinforcements (Additional Projects)** | | | | | | |
| NordBalt Cable Phase 2 | SE_S | SE_M | 700 | 2023 | 170–270 | 0.24–0.39 |
| Res in mid-Norway | NO_M | NO_N | 1,200 | 2023 | 870–1,500 | 0.73–1.25 |
| Great Belt II | DK_W | DK_E | 600 | 2030 | 390–480 | 0.65–0.8 |
| Sweden north-south reinforcement | SE_M | SE_N2 | 700 | 2030 | 800–1,400 | 1.14–2.0 |
| **Sum of additional costs** | | | | | **2,230–3,650** | |
| **Total cost of the High integration of grids scenario** | | | | | **3,604–6,020** | |

Own illustration; Interconnections constitute the high integration of grids scenario, together with net transfer capacities and their respective costs. They are divided into projects among core countries, internal reinforcements to be commissioned by 2030 and projects among third countries to be commissioned by 2025 (as with the moderate integration of grids scenario). All are based on the TYNDP. In the total cost are included the costs from the moderate scenario as well.

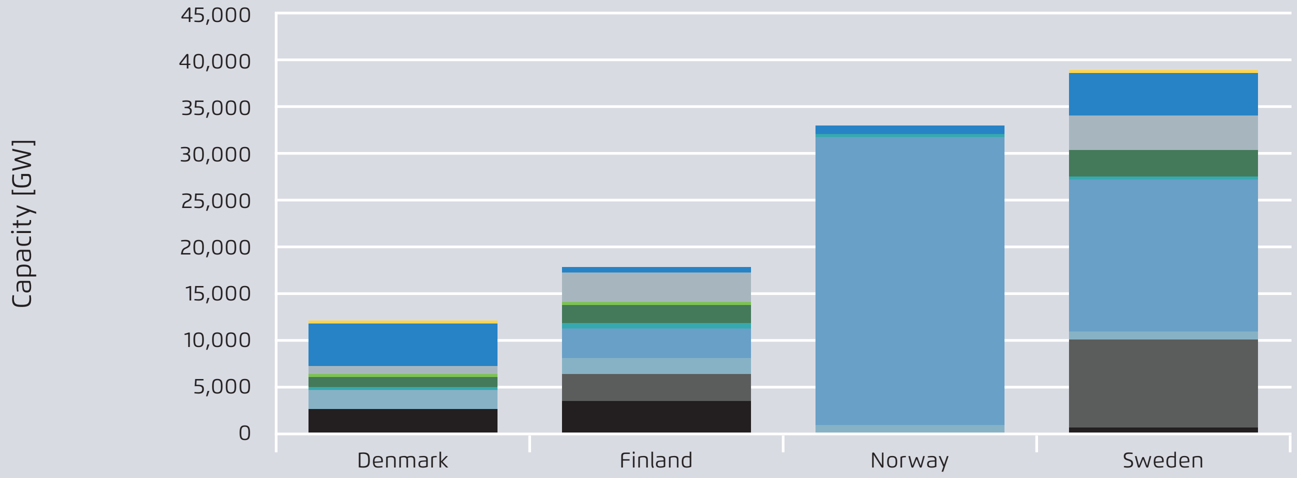
# 3 Existing power system

**Denmark**
The Danish power system is characterised by both centralised and decentralised CHP and a relatively high proportion of wind power. The large power plants are mainly located in bigger cities, where there are district heating networks that benefit from cogeneration and heat. Denmark uses a variety of fuels for electricity generation, mainly coal and gas, but also biomass.

The model represents the Danish electricity and cogeneration system in detail. The large power units are shown individually, while the decentralised plants are aggregated into groups by plant type.

**Finland**
Power generation in Finland takes place with a mix of different technologies: nuclear power plants, hydro power facilities as well as thermal power plants based on coal, biomass and natural gas. Finland also imports around 4-5 TWh from Russia.

Electricity generation capacity by fuel and country (2013). Figure 6




| | Denmark | Finland | Norway | Sweden |
|---|---|---|---|---|
| Solar | 232 | 0 | 0 | 43 |
| Wind | 4,611 | 448 | 811 | 4,470 |
| Other | 1,121 | 3,609 | 338 | 3,894 |
| Biogas | 64 | 19 | 0 | 0 |
| Biomass | 919 | 1,921 | 0 | 2,686 |
| MSW | 290 | 516 | 20 | 486 |
| Hydro | 0 | 3,140 | 30,960 | 16,150 |
| Natural gas | 2,156 | 1,805 | 710 | 840 |
| Nuclear | 0 | 2,752 | 0 | 9,531 |
| Coal | 2,505 | 3,402 | 0 | 437 |

Own illustration

**Norway**

Virtually all of Norwegian electricity production is based on hydro power (95 percent). The rest comes from natural gas, wind and biomass.

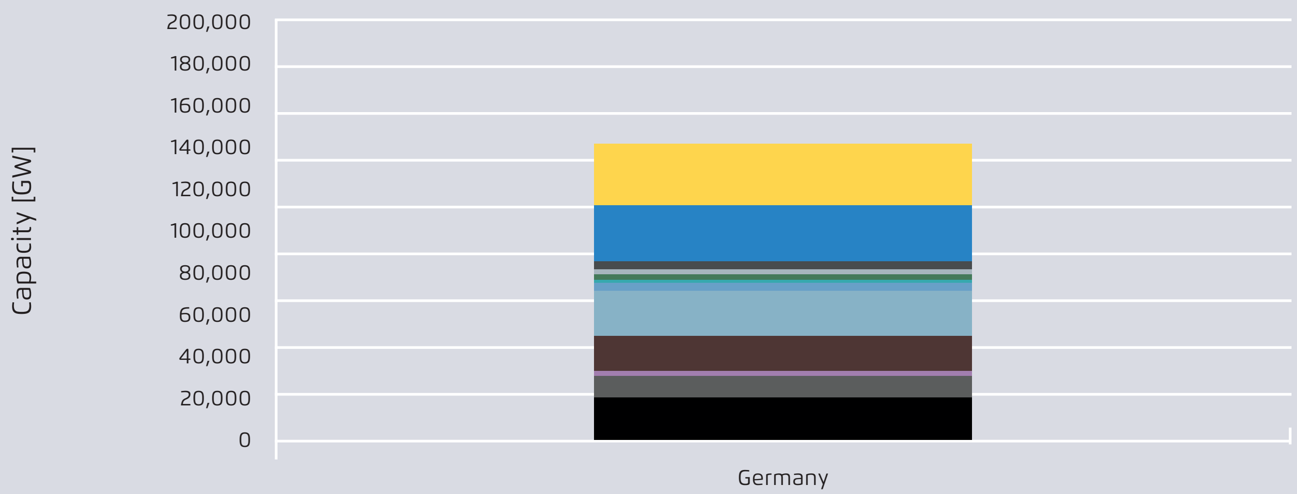
**Sweden**

Sweden, like Norway, has a large share of hydro power in the electricity system. In addition, Sweden has three operational nuclear power plants and cogeneration with a relatively high proportion of biomass.

**Germany**

Coal and lignite are still the most important sources of electricity generation in Germany, but generation from renewable energy sources has increased substantially in recent years, reaching 24 percent in 2013.[5] Firmly planned decommissioning of power plants is included in the data set, while other decommissioning is defined endogenously.

Installed capacities by fuel in Germany (2013). Figure 7




| | Germany |
|---|---|
| Solar | 35,099 |
| Wind | 33,730 |
| Other | 4,072 |
| Biogas | 4,286 |
| Biomass | 2,578 |
| MSW | 1,597 |
| Hydro | 4,629 |
| Natural gas | 26,372 |
| Lignite | 20,988 |
| Electric | 3,530 |
| Nuclear | 12,068 |
| Coal | 25,659 |

Own illustration

# 4 Modelling tool

## 4.1 Balmorel

The quantitative analyses are made with Balmorel, a least-cost dispatch power system model. The model is based on a detailed technical representation of the existing power system, power and heat generation facilities and the most important bottlenecks in the overall transmission grid. The main result in this case is a least-cost optimisation of the production pattern of all power units. Originally developed with a focus on the countries in the Baltic region, Balmorel is particularly strong in modelling combined heat and power production.

In addition to simulating the dispatch of generation units, the model is able to optimise investments in new generation units (coal, gas, wind, biomass, CCS etc.) as well as in new interconnectors. A separate analysis on the costs of establishing new interconnectors in the region has been prepared. This analysis estimates the price of potential new transmission lines in the region (Ea Energy Analyses 2012, Costs of transmission capacity in the Baltic Sea Region).

## 4.2 Geographical scope

The core countries regarded in this study comprise Germany, the Nordic countries (Norway, Denmark, Sweden and Finland) and the remaining countries in the Baltic Sea region (Estonia, Latvia, Lithuania and Poland). In addition, the model contains data on the surrounding countries (Netherlands, Belgium, France, Italy, Switzerland, Austria, the Czech Republic, Great Britain and Ireland) to account for interdependencies. Figure 8 shows an overview of the geographical segmentation in the modelled countries.

Some countries are divided into regions to account for potential transmission bottlenecks within the electricity system. In this study, Germany is considered one electric region.

## 4.3 Technology data

The data on power plants is based on the model's inventory, which is continuously updated as decisions on commissioning and decommissioning of power plants in the region are made.

**Input to Balmorel**

This section describes specific technical data for the power plants in the Nordic countries and Germany. Furthermore, the exogenously defined power plant capacity is described for all countries in the model for the base scenario.

In the Balmorel model, the individual power stations or types of power stations (aggregated groups) are represented by different technical and economic parameters, e.g.

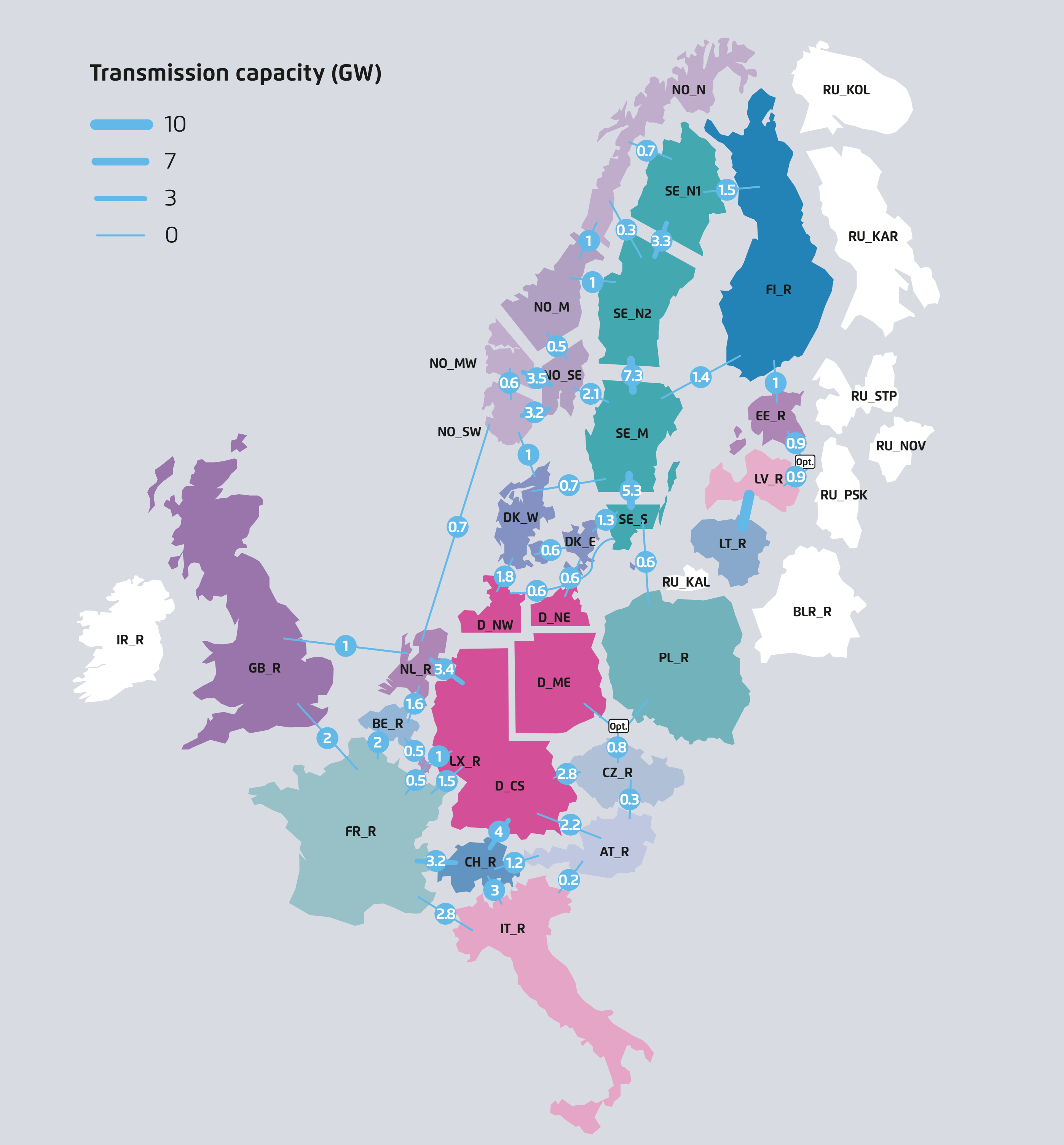
- → Technology type
- → Type of fuel
- → Capacity
- → Efficiency
- → $C_b$ and $C_v$ values for extraction and backpressure CHP plants
- → Desulphurisation
- → $NO_x$ emission coefficient
- → Variable production
- → Fixed annual production
- → Investment costs

It is possible to specify any type of fuel in the model – oil, natural gas, biomass, etc.

The capacities in the model are given as net capacities for either electricity or heat. For extraction units, the capacity is given as the electrical capacity in condensing mode; for backpressure units it is given as the electricity capacity in co-generation mode.

In full cogeneration mode at CHP units, the $C_b$-value specifies the ratio between electricity and heat. For extraction

Overview of the geographical segmentation of the modelled countries with indicated magnitude of electrical interconnection capacity (as of 2013). In this study Germany is considered one electric region and internal congestions are disregarded. Figure 8




Own illustration

units, the $C_b$-value specifies the loss in electricity when producing heat for maintained fuel consumption. The fuel efficiencies in the model are for CHP units given as the fuel efficiency in condensing mode for extraction units and the total fuel efficiency in CHP mode for back pressure units. Fuel efficiencies are defined on an annual average basis.

The model calculates hydro plant generation using the capacity and a set of full load hours given specifically for each area.

The aggregated data on existing and planned plants in 2030 is presented below. The data regarding heat-only boilers is not represented in this overview. The data is based on National Renewable Energy Action Plan (NREAP) reports, as well as (for Germany) on the German Energiekonzept 2050 and (for Denmark) on the assumptions of the Danish TSO, Energinet.dk.

**Decommissioning of power plants**

The decommissioning of thermal power plants can take place exogenously or endogenously. The exogenous approach is based on data about the year of commissioning and assumptions about typical technical lifetime. In the endogenous approach, the model can decide to decommission a power plant when it is no longer profitable to operate, that is, when operational earnings no longer cover operation and maintenance costs.

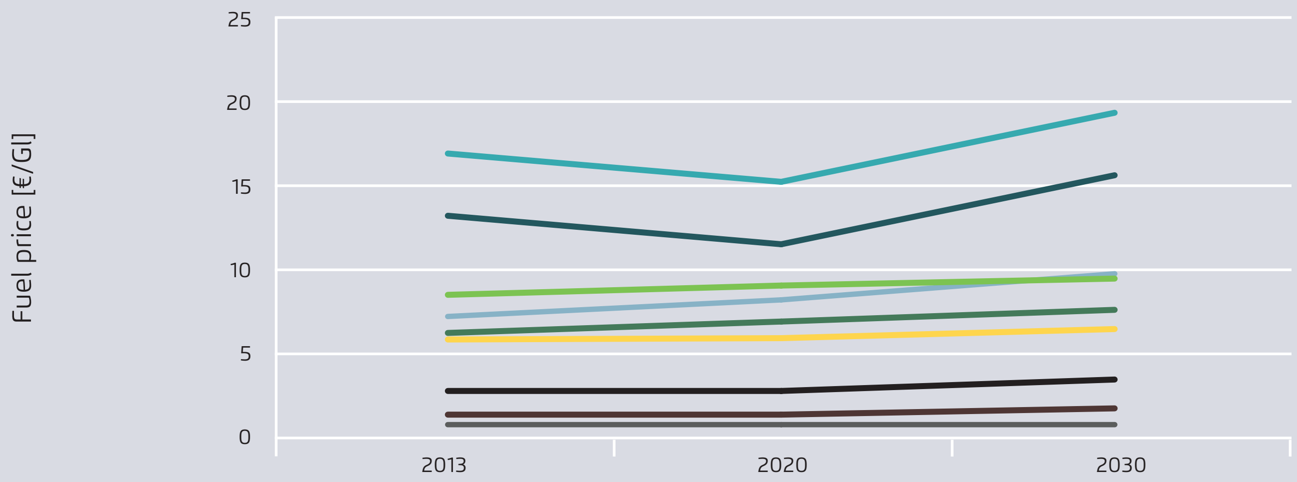
# 5 Fuel price and $CO_2$ quota price projection

**Fossil fuel prices**

The fuel prices of coal, oil and gas in this study are based on the IEA New Policies Scenario presented in the IEA's World Energy Outlook, November 2013 (see the figure below). The New Policies Scenario, which covers the period 2012–2035, assumes that the current G20 low carbon agreements have been implemented.

The World Energy Model (WEM), the main tool used in the development of the IEA WEO scenario projections, operates under the assumptions of long-term equilibrium, i.e. a state of the economy where the general price level fully reflects – and is adjusted to – existing main price drivers and market factors. In the short- to medium-term, however, it is reasonable to assume that the price projections based on the best available actual market information would be more representative. For this reason future/forward contract prices have been used for price pathway projections in the short-term and the IEA scenario projections in the longer-term.

Fuel prices for model simulations | Figure 9




| | 2013 | 2020 | 2030 |
|---|---|---|---|
| Coal | 2.7 | 2.8 | 3.4 |
| Lignite | 1.4 | 1.4 | 1.7 |
| Fuel oil | 13.3 | 11.6 | 15.7 |
| Light oil | 17.1 | 15.4 | 19.5 |
| Natural gas | 7.2 | 8.2 | 9.9 |
| Nuclear | 0.7 | 0.7 | 0.7 |
| Straw | 5.9 | 6.0 | 6.5 |
| Wood | 6.3 | 7.0 | 7.6 |
| Wood pellets | 8.5 | 9.1 | 9.5 |

Own illustration

Global efforts to combat climate change will reduce the demand for fossil fuels at the global level relative to a situation with no or limited climate change regulation. According to the International Energy Agency (IEA), increases in prices of coal, oil and natural gas will be relatively moderate.

All fuel prices are assumed to be same in all modelled countries – except natural gas prices in Russia and Norway, which are assumed to be 10 percent lower due to the proximity of local resources. In recent years Russian gas prices have been around a third of European prices. In accordance with the official policy of Russia, we expect that Russian gas prices will gradually converge towards the European price level (minus the abovementioned 10 percent discount).

**Biomass prices**
Biomass and biogas prices are based on a study by the Danish Energy Agency (2013).

**$CO_2$ quota prices**
The $CO_2$ price projected by the WEO 2013 for 2030 is used. For 2020 the forward price is applied.

$CO_2$ price for model simulations — Table 5

| | €/ton |
|---|---|
| 2013 | 4,9 |
| 2020 | 5,8 |
| 2030 | 25,9 |

Based on World Energy Outlook 2013

# 6 Electricity and heat demand

**Electricity demand**

The gross electricity demand is based on the information provided in the NREAP for each of the EU countries in the region. For Norway it is based on the ENTSO-E report[6] and projections made for the BASREC Post Kyoto study.

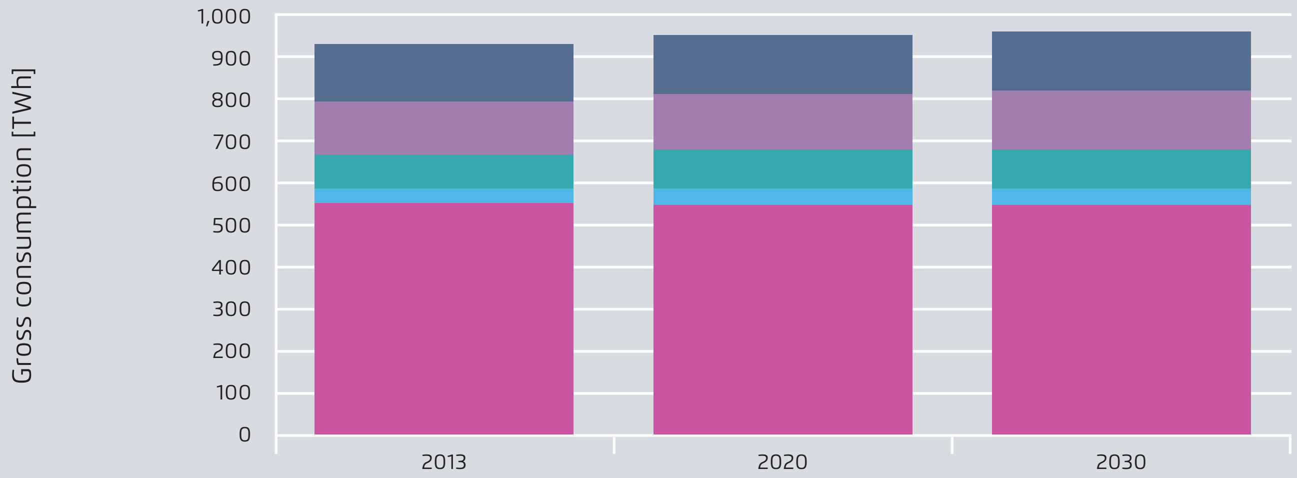
In the base scenarios, demand is assumed inflexible and has to be fulfilled at all times, except when the electricity price rises above 3000 €/MWh (at which point demand is cut off) and when the electricity price falls below -500 €/MWh (at which point demand increases). These exceptions correspond to the price floor and price ceiling in the Nord Pool Spot power market.

The effect of flexible demand is analysed in a separate sensitivity analysis. Flexible demand is here defined as electricity demand response that shows price elastic demand, e.g. that can shift electricity consumption from high price hours to low price hours. This is known as *load shifting*. One example is when some of the electricity demand from peak hours during the day is moved to low price hours at night.

The level of flexible demand is assumed to correspond to 10 percent of the peak demand in each region. This number is a rough estimate, which is meant to illustrate the effect

6 ENTSO-E "Scenario Outlook and System Adequacy Forecast 2011-2025"(ENTSO-E, 2011).

Projected electricity demand for individual countries (including grid losses but excluding own consumption on power plants, electricity consumption for district heat production (e.g. large heat pumps) and electricity consumption for pumped hydro storage). Figure 10




| | 2013 | 2020 | 2030 |
|---|---|---|---|
| Sweden | 137 | 140 | 139 |
| Norway | 128 | 132 | 139 |
| Finland | 84 | 94 | 94 |
| Denmark | 35 | 37 | 40 |
| Germany | 555 | 553 | 552 |

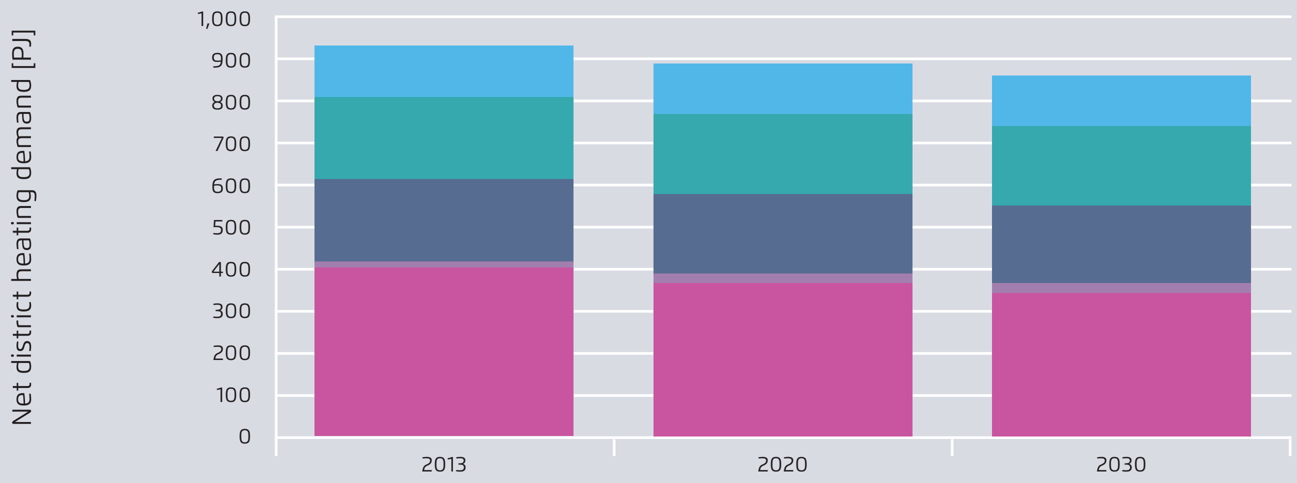
Own illustration

that flexible demand can have on, say, the value of transmission capacity. The flexible demand is modelled as virtual electricity storage without associated losses or costs, i.e. total demand is unaffected over a longer period, but load is shifted within the period without costs. The maximum content in electricity storage corresponds to 4 hours of loading at a level of 10 percent of the peak demand.

### District heating demand

The development in heat demand for 2013–2030 is based on figures from the EU Commissions scenario report "Energy Trends 2030" (2010). The net heat demand can be seen in the figure below. A network loss of 21 percent in all district heating networks is assumed.

Net district heating demand for 2013, 2020 and 2030 per country in PJ. Figure 11




| | 2013 | 2020 | 2030 |
|---|---|---|---|
| Denmark | 118 | 119 | 120 |
| Finland | 197 | 190 | 188 |
| Sweden | 194 | 191 | 186 |
| Norway | 15 | 19 | 26 |
| Germany | 399 | 369 | 343 |

Own illustration

# 7 RE development for Germany

**RE development**

The future development of renewable energy for electricity production is set out in the law for renewable energy, with its latest amendment in 2014.[7] The law defines targets and support levels for different types of renewable energies. Important changes of the latest amendment include:

- → A lower target for the development of offshore wind power by 2020. Total capacity target of 6.5 GW for 2020 and 15 GW for 2030.
- → A desired capacity expansion of 2500 MW onshore wind power capacity per year. (Net expansion, taking into account the decommissioning of older wind turbines.)
- → A lower target for the development of biomass-fired electricity production. A maximum 100 MW of new capacity per year (gross).
- → A lower target for the development of solar power and a total limit of around 52 GW. A maximum 2500 MW of new capacity per year (gross).

With these targets, the share of renewable energy of gross electricity consumption is projected to increase to 40–45 percent by 2025 and to 55–60 percent by 2035.

**Moderate RE deployment**

For the purpose of defining the development of RE in terms of both capacity and electricity production, various sources have been used. Their main aim is to interpret the latest revision of the Renewable Energy Act (2014) and to assess the development of RE as a result of the revised law. As such, the development of RE is heavily dependent on the concrete political actions and possible future amendments of the law for renewable energy. Nevertheless, it is considered the best estimate currently available.

An overview of capacity for different RE sources, including future development through 2035, is given in the table below. The main source for the actual capacity by 2025 and 2035 is scenario B in the scenario framework proposal for the 2015 network development plan by the German transmission system operators (the 2015 NEP framework).[8] This scenario aims at fulfilling the upper bound of RE share mentioned in the law for renewable energy.

7 German Federal Ministry for Economic Affairs and Energy (2014): Gesetz für den Ausbau erneuerbarer Energien, http://bmwi.de/BMWi/Redaktion/PDF/G/gesetz-fuer-den-ausbau-erneuerbarer-energien,property=pdf,bereich=bmwi2012,sprache=de,rwb=true.pdf

8 50Hertz, Amprion, TenneT, TransnetBW (2014): SZENARIORAHMEN FÜR DIE NETZENTWICKLUNGSPLÄNE STROM 2015, April 2014, draft – not approved by the German regulator

Installed capacity for RE in Germany — Table 6

| GW | Installed capacity 2013 | Added capacity 2014 | Installed capacity 2020 | Installed capacity 2025 | Installed capacity 2035 |
|---|---|---|---|---|---|
| Onshore wind | 33.2 | 3.5 | 49.5 | 60.2 | 82.2 |
| Offshore wind | 0.5 | 1.6 | 6.7 | 10.5 | 18.5 |
| Solar power | 35.1 | 2.5 | 52.0 | 55.7 | 60.7 |
| Biomass + Biogas | 6.7 | 0.06 | 7.12 | 7.4 | 8.8 |
| Biomass | 2.4 | 0.03 | 2.6 | 2.8 | 3.5 |
| Biogas | 4.3 | 0.03 | 4.5 | 4.6 | 5.3 |
| Hydro power | 4.6 | 0.01 | 4.7 | 4.7 | 4.9 |
| Pumped hydro storage | 6.4 | 0.18 | 7.6 | 8.5 | 12.6 |
| Municipal solid waste | 1.6 | 0.0 | 1.6 | 1.6 | 1.6 |
| Geothermal power generation | 0.03 | 0.05 | 0.4 | 0.6 | 0.6 |

Own illustration, *Based on average development through 2025.

For modeling purposes, the amount of generated electricity for different types of RE is needed as a minimum in addition to defining installed capacities. The required amounts are calculated based on assumptions for the number of full load hours for the generators (see table 7).

### Approach to modeling of RE generators for Germany

The development of RE in the model simulations is defined exogenously in terms of generated electricity by RE sources. The model invests endogenously in technologies to fulfill these requirements. The main sources for defining the development of RE in Germany are listed in table 8.

### Regional distribution of RE generators

The regional distribution of existing capacities is based on PPL. Distributions of future RE generators is based on model optimisation. For wind power the regional distribution is limited by regional potentials for wind power, which are based on the maximum installed capacities in individual regions as defined in NEPf2015.

### Onshore wind

According to the 2015 NEP framework, the total installed onshore capacity by the end of 2013 was 33.2 GW, somewhat lower than the 33.8 GW stated by the Ministry for Economic Affairs and Energy.[9] The reasons for deviation are assumed to be different dates for the registration of renewable sources and actual grid connection. For 2014, the German Wind Energy Association expects an additional capacity of around 3.5 GW.[10] With these numbers, an additional net capacity of 2.13 GW per year through 2024 and an additional capacity of 2.2 GW per year between 2025 and 2035 are necessary to achieve the total capacities stated in the 2015 NEP framework. This yearly develop-

9 Zeitreihen zur Entwicklung erneuerbaren Energien in Deutschland, February 2014.

10 http://www.wind-energie.de/en/press/press-releases/2014/onshore-wind-power-statistics-first-half-2014-germany-onshore-wind-power-0

Assumptions for full load hours to calculate power generation based on future capacities Table 7

| | Old | New 2014 | New 2035 |
|---|---|---|---|
| Wind onshore | 1,600 | 2,100 | 2,100 |
| Wind offshore | DE_NW: 4,200 | DE_NW: 4,200 | DE_NW: 4,200 |
| | DE_NE: 4,100 | DE_NE: 4,100 | DE_NE: 4,100 |
| Solar | 900 | 900 | 900 |
| Biomass | 5,500 | 5,500 | 4,000 |
| Biogas | 7,100 | 7,100 | 4,000 |
| Hydro | 3,800 | 3,800 | 3,800 |
| MSW | 6,600 | 6,600 | 6,600 |
| Geothermal | 3,000 | 3,000 | 3,000 |

Own illustration

Sources for development of RE in Germany Table 8

| Source | Type of data used |
|---|---|
| Renewable Energy Act EEG, August 2014* (EEG) | Not used directly, but important background for general development and the NEP scenario framework |
| Scenario framework proposal for the 2015 grid development plan, German TSOs (NEPf 2015)[10] | Main source for installed capacity and capacity development |
| Power plant list, updated February 2014, Bundesnetzagentur (German regulator) (PPL) | Main source for regional distribution of existing capacities (RE and conventional). Source for firmly planned future decommissioning of conventional power plants |
| Statistics on development of renewable energies in Germany, February 2014 | Source for historical development of full load hours. Source for historical development of installed capacity (and future decommissioning) |

Own illustration; *German Federal Ministry for Economic Affairs and Energy (2014): Gesetz für den Ausbau erneuerbarer Energien, http://bmwi.de/BMWi/Redaktion/PDF/G/gesetz-fuer-den-ausbau-erneuerbarer-energien,property=pdf,bereich=bmwi2012,sprache=de,rwb=true.pdf, SZENARIORAHMEN FÜR DIE NETZENTWICKLUNGSPLÄNE STROM 2015, April 2014, 50Hertz, Amprion, TenneT, TransnetBW, draft – not yet approved by the German regulator. In the following, this draft will be referred to as "2015 NEP framework".

ment is somewhat below the desired additional capacity of 2,500 GW stated in the law for renewable energy.

### Offshore wind

According to the proposed 2015 NEP framework (draft), the total installed capacity by the end of 2013 was 0.5 GW. As for onshore wind, numbers are somewhat below the 0.9 GW indicated by the Ministry for Economic Affairs and Energy. According to the list of offshore projects available by the Foundation Offshore Wind Energy, the total additional capacity for 2014 is 1.6 GW.[11] With an annual net additional capacity of 0.77 GW per year through 2025, the targets of 6.5 GW by 2020 stated in the law for RE and of 10.5 GW by 2025 stated in the 2015 NEP framework can be reached. Between 2030 and 2035 an additional capacity of 0.80 GW per year is assumed. The distribution of additional capacity follows the assumptions made in the 2015 NEP framework (see table below).

Assumptions for total installed offshore capacity — Table 9

| GW | 2025 | 2035 |
|---|---|---|
| North Sea | 8.8 | 13.5 |
| Baltic Sea | 1.7 | 5 |

Own illustration

### Solar Power

According to the Ministry for Economic Affairs and Energy, the total installed power capacity of solar power was 35.9 GW. This number is lower than the accumulated capacity of 36.6 GW in the German Network Agency's power plant list. A net additional capacity of around 2.5 GW per year will result in 52 GW by 2020 – the cap in the RE law – after which subsidies will be reduced. Additional capacity after 2020 is therefore around 0.75 GW through 2025 and 0.5 GW through 2035. These are the total capacities stated by the 2015 NEP framework.

11 offshore-windenergie.net

### Biomass

RE production from RE is divided into two main categories, both representing a number of different technologies (see table 10). The proposed 2015 NEP framework provides only one category for biomass (containing biogas as well as solid and liquid biomass). Other RE gases[12] are mentioned in a category for other RE sources together with geothermal power. For the current installed capacity, biogas and biomass are kept separate. This distinction is based on numbers provided by the Ministry for Economic Affairs and Energy, scaled slightly to match the capacity in the 2015 NEP framework. For future development, the capacities are increased to meet the capacities in the 2015 NEP framework. Capacity additions are shared equally between biogas and biomass.

### Hydro power

The development of hydro power in the 2015 NEP framework focuses mainly on pumped hydro storage, while capacities for run-of-river and hydro power plants with reservoirs are kept almost constant through 2035. The Balmorel model distinguishes three different types of hydro power:

- → Run-of-river plants: Hydro power production without storage options. Production variation is dependent on the inflow and based on historic production profiles.
- → Hydro plants with reservoirs: Hydro power production with the option to store water. Production is dependent on water inflow only to some extent, and production is optimized according to power prices. But storage options are limited by inflow profiles and storage capacities.
- → Pumped storage: Power plants that use electricity to pump water into storage for later electricity production.

In reality, some pumped storage plants see a certain degree of inflow to their storage reservoirs, which is neglected here. The total installed capacity of pumped storage plants is taken from the 2015 NEP framework, while regionalisation is based on information from the power plant list. For

12 These are not necessarily RE gases, but they are supported under the German RE scheme: Sewage gas (*Klärgas*), fire damp (*Grubengas*) and landfill gas (*Deponiegas*).

Categories used for modelling biomass — Table 10

| Category | Technologies | Modeled as |
|---|---|---|
| Biomass | Solid biomass, liquid biomass | Solid biomass |
| Biogas | Biogas, sewage gas, fire damp, landfill gas | Biogas |

Own illustration

the remaining hydro power plants, the 2015 NEP framework mentions only the total capacity, while the division of run-of-river and hydro reservoir plants is based on PPL.

**Municipal solid waste**

The total capacity of waste incineration plants is around 1.6 GW according to the 2015 NEP framework, and no significant development is expected through 2035. The incineration plants are assumed to burn both the fossil fuel part and the renewable part of municipal solid waste.

**Geothermal**

The contribution of geothermal based power generation arises from the capacity targets in the 2015 NEP framework.

**Nuclear power**

In accordance with the German government's resolution, all nuclear power plants are assumed to be decommissioned by 2022/23.

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