Nordic Grid Development Plan 2014

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Vi forbinder energi og mennesker

Nordic Grid Development Plan

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Preface

The Nordic transmission system operators (TSOs) have a long history of successful cooperation within grid development. Three common Nordic grid master plans have been developed in the last ten years in the context of Nordel, the previous cooperative organisation for the Nordic TSOs. The present plan follows along the lines of the Nordic Grid Development Plan 2012 based on the ENTSO-E joint regional planning.

Joint Nordic grid development is essential to support further development of an integrated Nordic electricity market, as well as increased capacity to other countries and integration of renewable energy sources (RES).
The Nordic co-operation on grid development is now taking place within the wider regional context provided by the regional groups North Sea and Baltic Sea of ENTSO-E, the European organisation for TSOs, in addition to bilateral co-operation when required.

The Nordic Grid Development Plan 2014 is prepared as a response to the request from the Nordic Council of Ministers of 28 October 2013. The plan is prepared by Energinet.dk, Fingrid, Statnett and Svenska Kraftnät, and the Icelandic TSO Landsnet has provided input regarding the Icelandic grid. The plan presents Nordic grid investment candidates and their evaluation with a time horizon up to the year 2030.

15 August 2014

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1. Executive summary

The Nordic TSOs have a long tradition of cooperating in grid and market development in order to secure the supply of electricity to the consumers, based on a regional perspective. This tradition continues to this day in the ENTSO-E particularly as well as in specific joint studies where two or more TSOs participate and in business case studies where interconnector projects are matured and decided.

The Nordic Grid Development Plan 2014 (NGDP14) follows the lines of the Nordic Grid Development Plan 2012 in being an extract from the ENTSO-E Regional plans from the North Sea and the Baltic Sea. In contrast to the 2012 plan, which looked towards 2020, this year's plan is a view towards 2030, and calculations done in the process assess the market in 2030 and the feasibility of possible interconnector and other grid development projects at that point in time.

The plan is founded on the analysis and studies done commonly in the two regional groups where an even larger area has been the focus of the study, according to the regions defined within ENTSO-E. Common market and grid analysis were performed and based on a number of scenarios and sensitivities. As such, this plan contains no new information compared to the ENTSO-E TYNDP 2014 package. The results are shown for the Nordic area especially.

1.1 What is new in the Nordic Grid Development Plan 2014?

Compared to the TYNDP12, the TYNDP14package has expanded its scope significantly; hence the NGDP14 does likewise. The main improvements are:

- The exploration of a longer run horizon, namely 2030, beyond the 10-year horizon, along four contrasted 'Visions', encompassing the futures that stakeholders required ENTSO-E to consider.

- New clustering rules to define projects of pan-European significance, focusing them on the most important investment items in a project.

- A numerical quantification of every project benefits assessment according to the consulted Cost Benefit Analysis (CBA) methodology, with refined definitions for the security of supply, Renewable Energy Source (RES) integration, socio-economic welfare, resilience, flexibility and robustness, social and environmental indicators.

All in all, the TYNDP presents a more holistic view of grid development, completing power transmission issues with environmental and resilience concerns.

1.2 The TYNDP 2014 explores four different visions of development until 2030

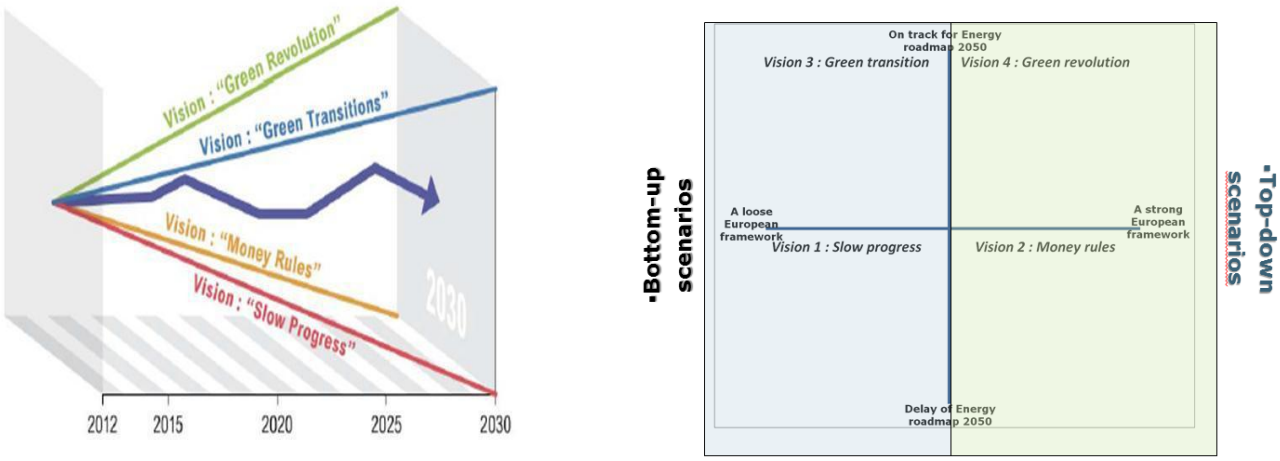


Figure 1 Illustration of the four scenarios and the connection between them.

The NGDP14 analysis is based on an exploration of the 2030 horizon. The year 2030 is used as a bridge between the European energy targets for 2020 and 2050. This choice has been made, based on stakeholders' feedback, preferring a large scope of contrasted longer-run scenarios instead of a more limited number and an intermediate horizon 2020-2025.

The basis for the NGDP14 analysis is **four Visions for 2030**. The Visions are not forecasts of the future, but possible development paths of the future. The aim of the visions is that the future will fall somewhere in between these with a large degree of certainty.

By 2030, the changes in the generation mix as described in the Visions will result in increased power flows between the regions and between the member states within the region.

Given the significant increase in volumes of RES in the Nordics, to avoid heavy curtailment of RES output, especially for visions 3 and 4 and to benefit from exchanges in the market, additional interconnection capacity could be required.

The future regional power system has the following main characteristics:

- A shift from thermal to renewables.
  This generation shift causes new transport patterns, which increases the need for more flexibility in the transmission system. Adding interconnectors to the system is one way of providing flexibility. This flexibility is required in order to integrate renewables whilst maintaining adequate security of supply.

- A shift from coal to gas.
  In visions 3 and 4, very high CO2 prices are assumed, leading to

generation from coal, to a large extend, gets priced out of the market. The analysis shows that new interconnectors between the different synchronous areas of Europe lead to large reduction of the regional CO_2-emissions. Especially interconnectors going between

- the hydro-based Nordic system with seasonal patterns and
- the increasingly wind/solar-based UK and continental systems with hourly patterns contributes both to a large amount of renewables in the system and to a large reduction of the regional CO_2-emissions.

In addition to this generation shift, future decisions on nuclear power plants will be important for the Nordics. In Finland nuclear power plants might improve the security of supply, whereas in Sweden potential decommissioning of nuclear power plants might lead to a challenging security of supply-situation.

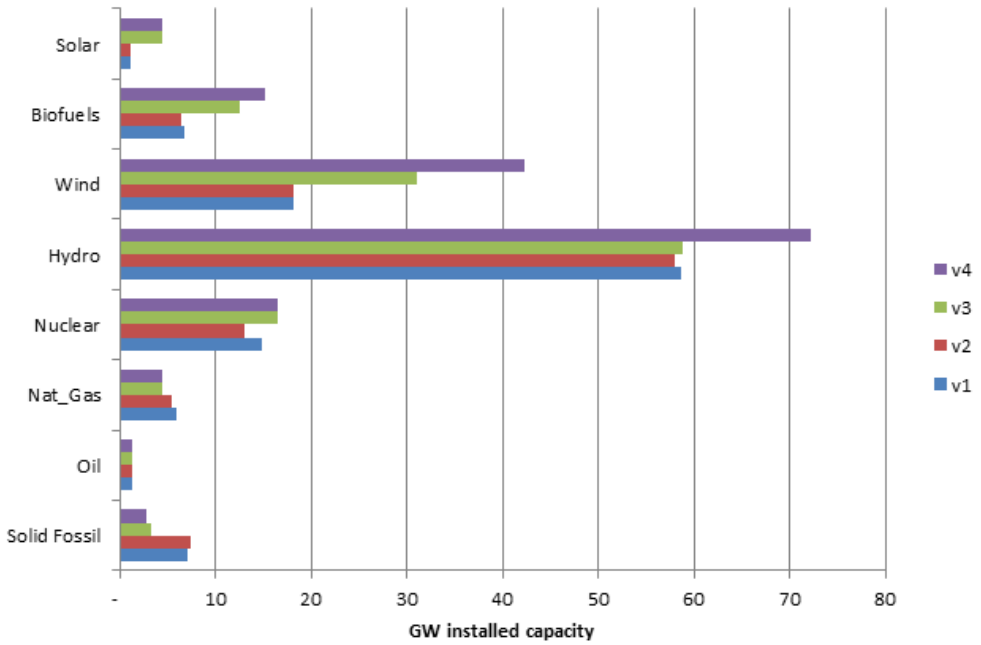


Figure 2 Installed generation capacity in the Nordics in Visions 1, 3, 3 and 4. Installed capacities are in total: V1: 114 GW; V2: 111 GW; V3: 133 GW; V4: 159 GW.

Even with four visions, there are still some uncertainties in the future system that affects the grid development planning. Among others: location of new RES capacity; interaction with third countries; evolution of nuclear capacity; competitiveness of generation investments. NGDP14 answers some of these uncertainties with sensitivity cases prepared in order to assess the effect of these. The three sensitivity cases prepared are:

- Reduced nuclear, with a reduced nuclear power capacity in Finland and Sweden compared to the reference cases.

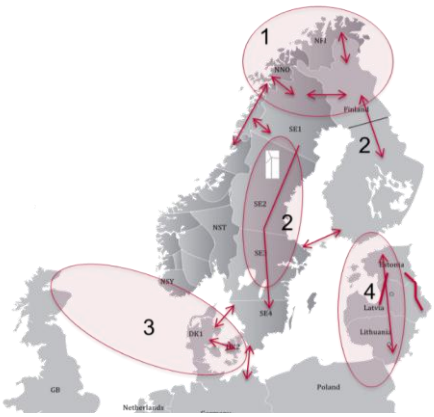
- Delays in project commissioning, where socio-economic welfare is calculated as an annual value in the market models with a delay of the four most beneficial projects (about 30%) with one year in each vision, which gives an indication of the upper bound of the total socio-economic welfare lost. Furthermore, the four least beneficial projects which gives an idea of a lower bound of the loss.

- Baltic Sea Green Vision, where the motivation of the study was to vary some of the elements that were common throughout Vision 1 to Vision 4, and to examine to what extent this kind of bottom-up scenario would fall inside the 'space' cornered by the common visions. The sensitivity is based on Vision 3, the latest IEA World Energy Outlook New Policies Scenario and the latest changes in regional generation scenarios.

1.3 Investment drivers in the Nordic Region

Scandinavia covers two different synchronous power systems, Continental Europe and the Nordic area, which are linked with HVDC connections. Currently the Nordic system is linked via several HVDC cables with Continental Europe.

The main drivers for system development in the region are the expected increase in renewable generation initiated by policy targets and higher primary energy prices, as well as the aim of securing a dynamic internal electricity market across Europe.



1. Planned RES integration and consumption increase in Northern Nordic region
2. North-South flows in Sweden/Norway/Finland
3. Increased capacity between Nordics and Continental Europe and UK
4. Baltic states North-South power transmission corridor between Nordic and Central Europe

Figure 3 Regional topics of interest, studied during exploratory studies.

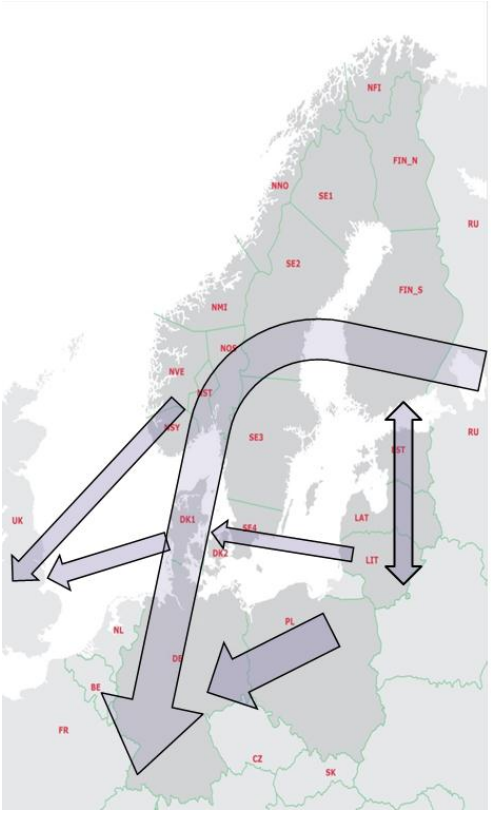
New connections between Nordic and Continental European countries are necessary to handle the changes in generation portfolios in the Continental countries and the Baltic Sea region. The nuclear phase out plan in Germany and further integration of RES into continental systems also make connections to the large hydro systems in the Nordic area more interesting. In addition to the existing and planned direct connections from the Nordic countries to central Europe, the transmission system of the Baltic States, after connection to the central European network through Poland, will serve as an alternative route between Nordic and Continental Europe.

1.3.1 Main flows from north to south

In visions 1 and 2 there are large north-south flows prevailing in the region and additionally some interchange of power from east to west, depending on the wind generation. Nordic power is exported to Central Europe mainly through Scandinavia-Continental Europe connection links. In the Baltics, the flows tend to be both, north and south bound, depending mainly on the RES generation in Nordics. As these visions have relatively low CO_2 prices compared to other two visions, Poland is a large exporter with its large thermal generation with a main direction to Germany.

The dominant energy flows are directed from the Nordics towards Central Europe and Great Britain. Energy flows are shown in Figures below.
In Vision 3 and 4 the flows are still mainly from the north towards central Europe, but the large amounts of intermittent energy results in more volatile flows on interconnectors, which especially can be seen on the interconnectors to the UK.

A major tendency in the visions is the energy flow from the Nordic countries to other areas of Europe. This is mainly facilitated by the surplus in the Nordic countries, where excess hydro, nuclear and wind power is available. Germany, Poland and the Baltic States are the main recipients of this energy. Germany is a net-importer especially in Vision 3 and 4 due to the phase-out of the nuclear power plants and present high share of coal power plants, of which competitiveness is reduced by the high CO_2 costs in visions 3 and 4. The main transmission direction will be north-south in the Baltic and the Nordic countries and east-west; west-east between Finland, the Baltic States and UK, Continental Europe.



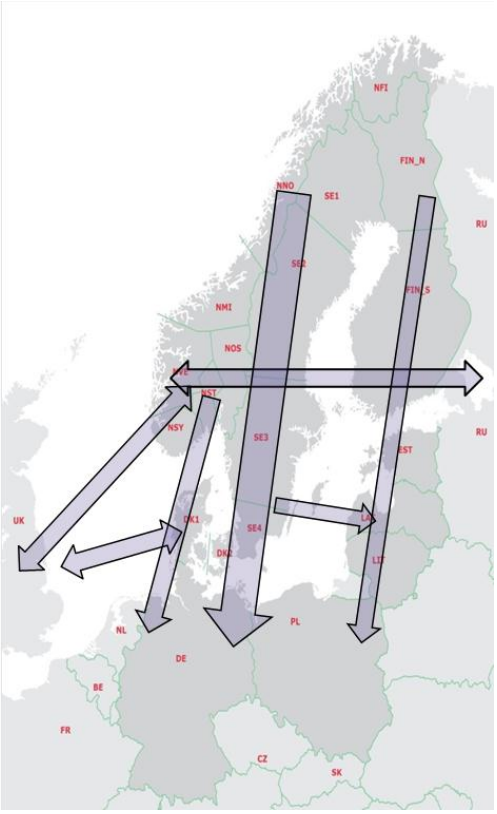


Figure 4 Bulk power flows in vision 1+2.

Figure 5 Bulk power flows in vision 3+4.

The largest bottlenecks appear on boundaries between Scandinavia and Central Europe and North – South flows from Northern Scandinavia to Southern Scandinavia, where interconnectors are loaded in range of 80-90% on average. Also interconnections from the Baltics to Nordics are heavily utilised, up to about 70% on average throughout the year.

1.3.2 Integration of RES

In the long-term, integration of new renewable generation and new or upgraded nuclear power plants are the main drivers of system evolution in the Nordic area. New wind power plants are planned to be built all around the region, but mainly concentrating on the coastal areas and the highlands in the North of the region and in Denmark. The new wind and hydro generation in the northern areas which already have a high surplus of energy requires a strengthening of the internal grid in north-south direction in Sweden, Norway and Finland, additionally to interconnection capacities between the countries.

The large hydro reservoirs can be utilised to balance the changes in wind and solar production as well as the demand fluctuations. Increased interconnection capacity is also needed for exporting the expected Nordic surplus. Without new interconnector capacity, there is a risk of locked-in power in Norway and Sweden

given the studied scenarios. Lack of grid capacity would most probably lead to lower investments in RES, and may therefore have a negative impact on the ability of achieving the RES targets. The high power flows between the Nordic area and Continental Europe will also create additional motivation for reinforcements within the Continental European grid.

1.3.3 Interconnectors – lead to decreased CO_2 emissions

Results of the analysis show that the investment portfolio presented in this plan increases flexibility and results in economic networks which facilitate the fulfilment of European targets; among others a low-carbon energy future. In order to be able to enable the generation shift, both from coal to gas and from thermal to renewables, a more flexible European power system is necessary. In such a flexible power system, interconnectors from the hydrological Nordic system seem to be very important. Interconnection assists in the replacement of thermal production with renewable generation, but also adds flexibility to the system by optimisation of the system generation despatch during peak/off-peak periods and in windy/non-windy periods.

The interconnectors between Norway/Sweden and Germany and between Norway/Denmark and UK show the highest influence of decreased CO_2 emissions of all the European Projects of Common Interest (PCI).

1.4 Investments and analysis results

In response to the investment needs, several interconnectors and internal reinforcements are analysed and assessed in the NGDP14. Part of the project portfolio was presented in the NGDP12, but are reassessed within framework of TYNDP 2014. The projects geographical location can be seen in Figure 6 and Figure 7

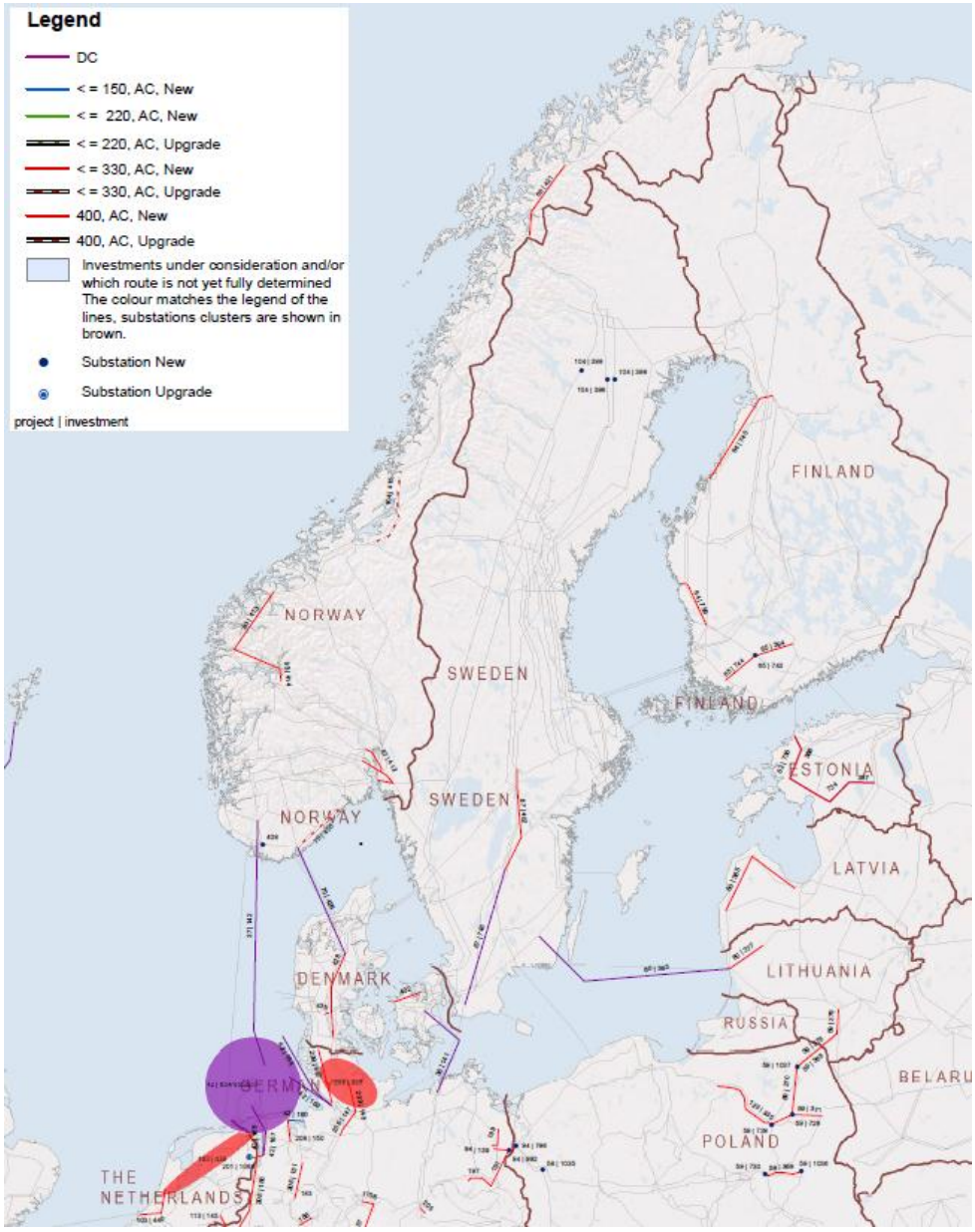


Figure 6 Medium-term projects.

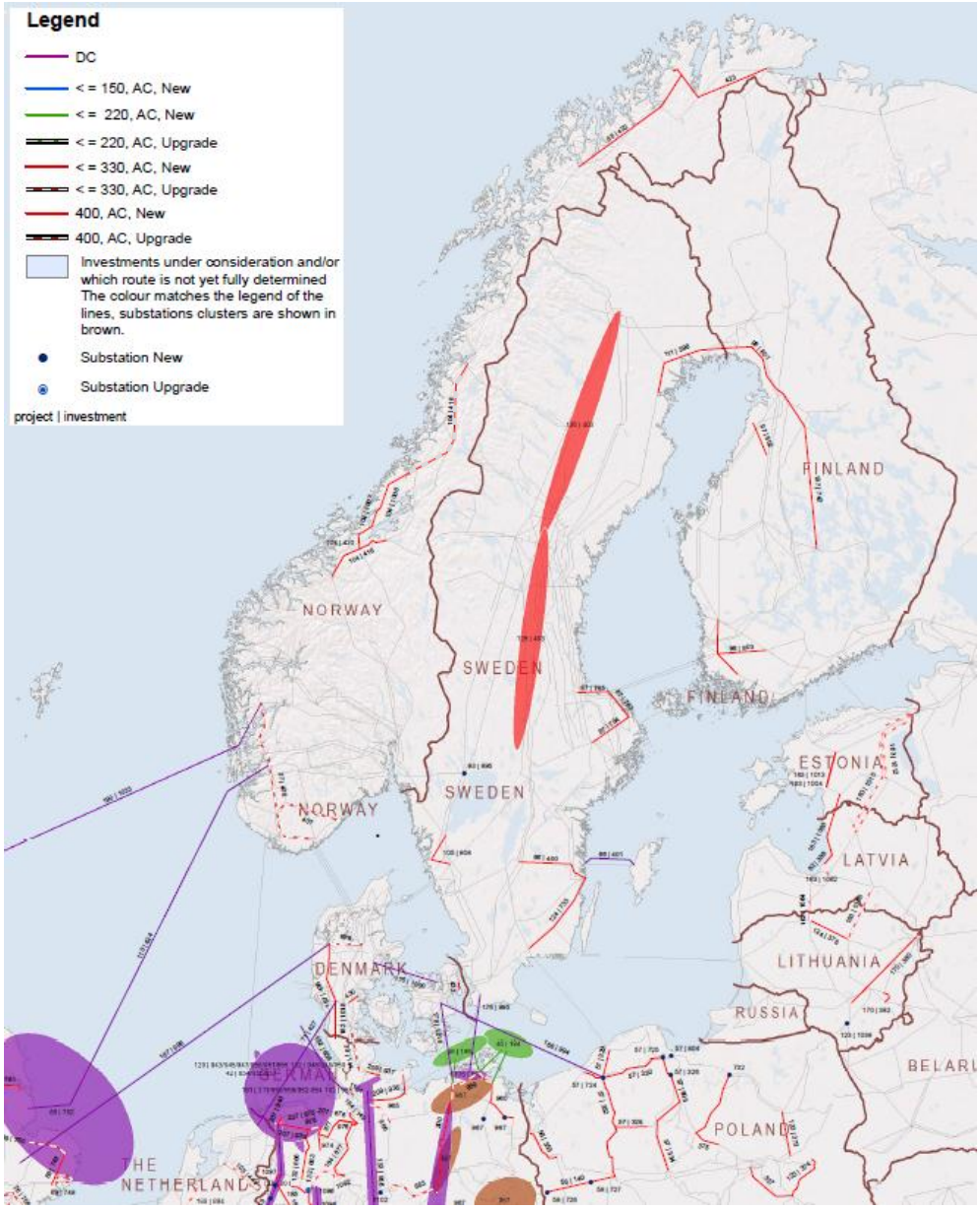


Figure 7 Long-term projects.

Results of the analysis show that the investment portfolio presented in this plan gives flexibility and provides a good and functioning infrastructure on the track towards the European vision of a competitive internal market and a low-carbon energy future. The planned investment portfolio is robust, resilient and beneficial. Due to the high amount of wind and solar power integration, it is crucial to ensure sufficient regulating power, which could even increase the benefits of the planned investment portfolio through better-functioning markets. Analysis also shows that not all assessed interconnectors are economically beneficial to build, but they may be important for other needs.

Of the investments presented in NGDP12, the majority remain on schedule. Some projects have changes in terms of commissioning date, status or in project detail. Delays are mainly caused by time consuming approval processes.

1.5 Main challenges regarding implementation

A major challenge is that the grid development may not be in time if the EU-wide targets are met. Permit granting procedures are lengthy, and may cause commissioning delays. If energy and climate objectives are to be achieved, it is of upmost importance to smooth the authorization processes. It is important to understand that delays in commissioning are additional cost to European society. Based on the regional sensitivity analysis, the delays will cause large losses in the socio-economic welfare for the whole Nordic region, compared to a situation where all projects are commissioned in time.

The large volume of projects in some countries represents a challenge in itself, as it requires increased implementation capacity both internally and in the suppliers' market. In addition, these investments will require extensive outages in the existing grid during construction and commissioning (especially voltage upgrading of lines and substations), which possibly could temporarily put security of supply at risk and could have a temporary negative impact on trading capacity. The existing electricity grid in the Nordic region is also quite old, leading to substantial needs for refurbishment which will further stress these issues.

There are also uncertainties regarding the market development on the EU-Russian border which subsequently have a significant impact on the flows on the interconnections to Russia. Also a significant uncertainty regarding the generator investments exists.

2. Introduction

The Nordic TSOs have a long tradition of cooperating on grid development, market development and operational questions. Before ENTSO-E was founded in 2009, where today the Nordic TSOs, along with the Baltic TSOs, Germany and Poland form the Baltic Sea Regional group; the Nordic TSOs produced several grid development plans under the NORDEL umbrella:

- 2002: Nordic Grid Master Plan analysing the bottlenecks
- 2004: Priority Cross Sections defining five prioritised projects
- 2008: Nordic Grid Master Plan; three new projects, analysing the connections to the Continent
- 2009 Multiregional plan together with Baltic, Polish and German TSO's

In 2009 European TSO cooperation was gathered in the new ENTSO-E organisation and regional cooperation in NORDEL was suspended. Also the cooperation on pan-European and regional grid development was re-organised, establishing regions comprising several countries in one region. For the Nordic TSOs this was an excellent opportunity to embed their existing cooperation into a wider regional context, thus ensuring further integration of the countries involved.

Since then under the ENTSO-E umbrella, two grid developments plan packages have jointly been developed and published: A 'package' consists of six Regional Investment Plans (RegIP – one for each European Region), a pan-European ten-year network development plan (TYNDP) and a report on system adequacy. A third package is on the way and the NGDP14 is built on this foundation. The joint development plan packages are:

- 2010: pilot TYNDP package.
- 2012: TYNDP package, based on joint regional market- and grid analysis.

2014: public consulting phase will start in July 2014, final reports to be published in December.

2.1 ENTSO-E

ENTSO-E is the European Network of Transmission System Operators – for electricity and was founded in 2009, based on the European regulation 714/2009, which also required the respective cooperation of the European regulators, which are organized in ACER. The general purpose of the regulation was to promote the development of the Electricity Infrastructure both within and between Member States, with special focus on cross-border exchange capacities between the Member States. This regulation requires a number of deliverables from ENTSO-E, one of them being the TYNDP.

In 2013, the European regulation 347/2013 came into force, defining the TYNDP as the sole basis for the elaboration of the European Projects of Common Interest (PCI).

Today, 41 TSOs from 34 European countries are collaborating in ENTSO-E. The working structure of the association consists of Working and Regional Groups, coordinated by four Committees (System Development, System Operations, Markets and Research & Development), supervised by a management board and the Assembly of ENTSO-E, and supported by the Secretariat, the Legal and Regulatory Group, and Expert Groups.

Co-operation of the European TSOs both on a pan-European and a regional level in order to undertake effective and efficient planning is the main requirement of the underlying regulations, and also ENTSO-E's mission and vision:

Mission

Being the body of transmission system operators of electricity at European level, ENTSO-E's mission is to promote important aspects of energy policy in the face of significant challenges:

Security - pursuing coordinated, reliable and secure operations of the electricity transmission network.

Adequacy - promoting the development of the interconnected European grid and investments for a sustainable power system.

Market - offering a platform for the market by proposing and implementing standardised market integration and transparency frameworks that facilitate competitive and truly integrated continental-scale wholesale and retail markets.

Sustainability - facilitating secure integration of new generation sources, particularly growing amounts of renewable energy and thus the achievement of the EU's greenhouse gases reduction goals

Vision

ENTSO-E's vision is to become and remain the focal point for all European, technical, market and policy issues related to TSOs, interfacing with the power system users, EU institutions, regulators and national governments. ENTSO-E's work products contribute to security of supply, a seamless, pan-European electricity market, a secure integration of renewable resources and a reliable future-oriented grid, adequate to energy policy goals.

Figure 8 Mission and Vision statement of the ENTSO-E.

In order to achieve this goal, ENTSO-E has established six regional groups for grid planning and system development tasks.

The Nordic TSOs are part of two of these regional groups as presented in Figure 9.

Figure 9 ENTSO-E regional gropus for Grid Planning – Nordic participation in Baltic Sean and North Sea Groups.

2.2 Expectation of the third legislative package on grid plans

The key requirement of the third package that forms the legislative driver for the 'Ten Year Network Development Plan' suite of documents is Article 8.3(b) of The Regulation EC 714/2009, whereby "The ENTSO for Electricity shall adopt: (b) a non-binding Community-wide network development plan, ...including a European generation adequacy outlook, every two years". The third package also includes a requirement to publish Regional Investment Plans every two years.

2.3 Expectations of the Nordic Council of Ministers

The Nordic Council of Ministers has requested a Nordic grid development plan to be provided every two years. The first Nordic biannual grid plan was presented at the Ministerial meeting of Nordic Energy ministers in autumn 2012.

This second grid development plan is based on the current collaborative work on the Regional Investment Plans for the ENTSO-E regions Baltic Sea and North Sea and is presented during summer 2014.

Iceland is not present in any of the Regional grid planning groups under ENTSO-E being separated from the other systems. Therefore Iceland is presented in a separate part of this plan, where developments in the Icelandic system are described.

3. Monitoring – status of previous Nordic prioritised grid investments

There has been a number of joint Nordic grid plans during the last ten years. Together they have identified around ten interconnectors and reinforcements that are important to the development of the common Nordic and European electricity market. In the following, we will give a short summary of the results from the different plans and an update on the current status of the reinforcements suggested.

3.1 Nordic Grid Maser Plan 2002

This was the first joint Nordic Grid Master Plan building upon many years of Nordic cooperation in grid planning. The plan looked at the future transport patterns in the Nordic transmission network and identified a number of important cross-sections which were to be subject to more detailed analyses in future plans.

In the analysis for the plan in 2002, the foreseen future energy balance in the Nordic area for the time period of 2005-2010 was negative. In the years leading up to the report there had been an energy surplus but the trend was negative with increasing demand and decommissioning of old generation units and very few new plants taken into operation. The analysis indicated an energy shortage and increasing interdependency on trade with neighbouring regions and a need for energy import to the Nordic area. This identified two major predicted transmission patterns: in east-west direction through the area, from Russia through Finland and Sweden to Norway and possibly to the UK and north-south between Norway/Sweden and the Continent. From this, and with the experiences from the market situation and grid operations taken into account, the following transmission needs were brought forward as being important and a priority for further studies:

- An increase in the transmission capacity of the HVDC interconnection between western Denmark and southern Norway through the establishment of an additional interconnection should be considered.
- Expansion through the establishment of an HVDC interconnection from southern Norway to eastern Denmark or southern Sweden should be considered.
- An increase in the transmission capacity of the HVDC interconnection between western Denmark and central Sweden through the establishment of an additional interconnection should be considered.
- An increase in the transmission capacity on the Hasle cross-section between eastern Norway and central Sweden should be considered.
- An increase in the transmission capacity between central Sweden and central Norway should be considered.
- Any need for additional initiatives aimed at improving the transmission capacity on internal Swedish cross-sections between central Sweden and southern Sweden should be established.

These needs are illustrated in the below figure.

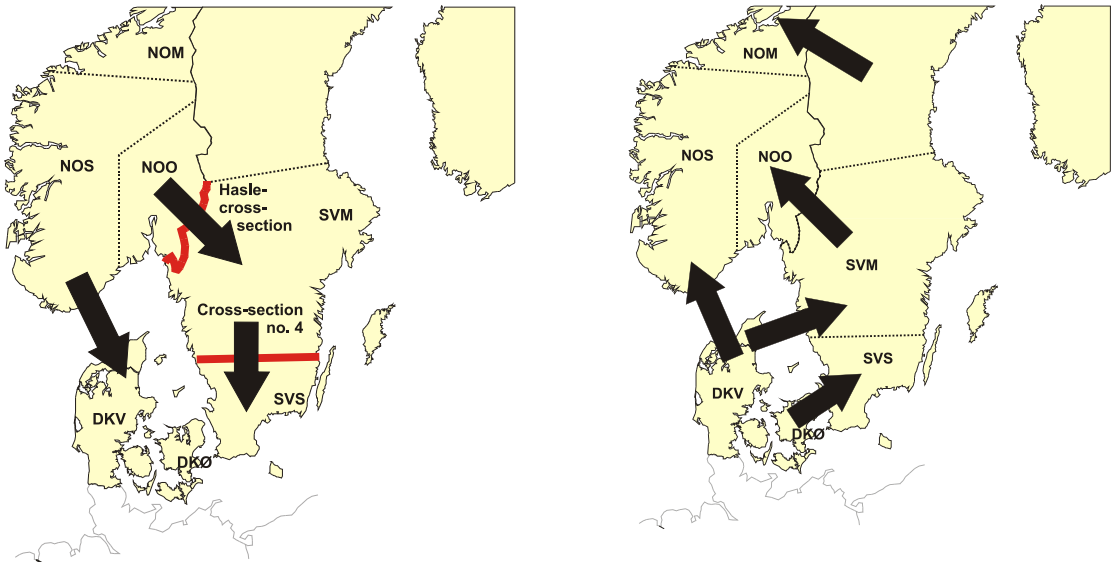


Figure 10 Identified transmission needs in Nordic Grid Master Plan 2002.

3.2 Priority cross-sections 2004

The follow-up of the 2002 Nordic Grid Master Plan 2002 was presented in 2004 in the Priority cross-sections report. In the report, an updated analysis of the predicted situation for 2010 was performed. The energy balance for the Nordic area looked more positive for 2010 than in the previous plan with the Nordic area roughly in balance between production and demand. Behind the assumption lay plans for new nuclear power in Finland as well as gas-fired production in Norway and more wind power.

The analysis identified typical transmission pattern in the Nordic area. Several transmission constraints were expected in these transport channels.

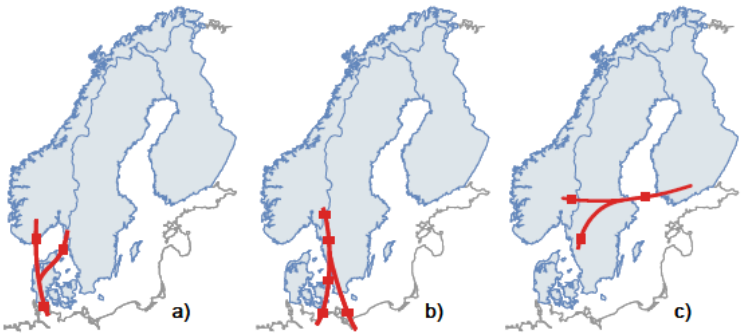


Figure 11 Expected transmission patterns in the Nordic Grid.

The report concludes that Nordel has identified five critical cross sections that would be beneficial to reinforce. These are:

Reinforcement	Earliest Commissioning Date	Status july 2014
The Great Belt connection	2008	Commissioned Sept 2010
Cross-section 4 in Sweden	2010	To be commissioned early 2015
Skagerrak between Norway and Denmark	2009	To be commissioned end of 2014
Fenno-Skan between Sweden and Finland	2010	Commissioned Dec 2011
Nea – Järpströmmen between Sweden and Norway	2009	Commissioned Sept 2009

Figure 12 Prioritized connections, Priority Plan 2004.

These five reinforcements were presented as a common Nordic reinforcement 'package', and the actual investments were to be handled bilaterally between the involved TSOs.

3.3 Nordic Grid Master Plan 2008

A new Nordic Grid Master Plan was presented in 2008. It looked at the situation in the Nordic area and the capacity to neighbouring countries given that the reinforcement package from the previous plan was implemented. The analysis was made in a scenario representing 2015 with the reinforcements in operation. Possible further reinforcements were identified and tested for robustness in four scenarios representing different energy market developments for 2025. The scenarios covered a spread of Nordic energy balances from a large surplus to a substantial deficit.

Based on the analysis, Nordel recommended that the TSOs started the planning process for reinforcement of the following internal Nordic cross-sections. All of these reinforcements showed a positive benefit in all four future scenarios.

Reinforcement	Earliest Commissioning date
Sweden – southern Norway (Hasle cross-section) • Realised through the SouthWest link	Prel. 2015

Sweden – Norway north-south axis • Realised through Ørskog –Fardal	Prel. 2013
Arctic region • Realised through Ofoten – Balsfjord – Hammerfest	Prel. 2014

Table 1 Reinforcements, Nordic Grid Master Plan 2008.

The analysis also showed high benefit for additional interconnectors between the Nordic area and neighbouring areas. However, since no external parties had been part of the study and no comprehensive analysis of internal reinforcements had been made, Nordel recommended that further studies should be made within the multiregional planning cooperation between Nordel, Baltso and Union for Coordination and Transport of Electricity (UCTE – the previous association for TSOs in continental Europe).

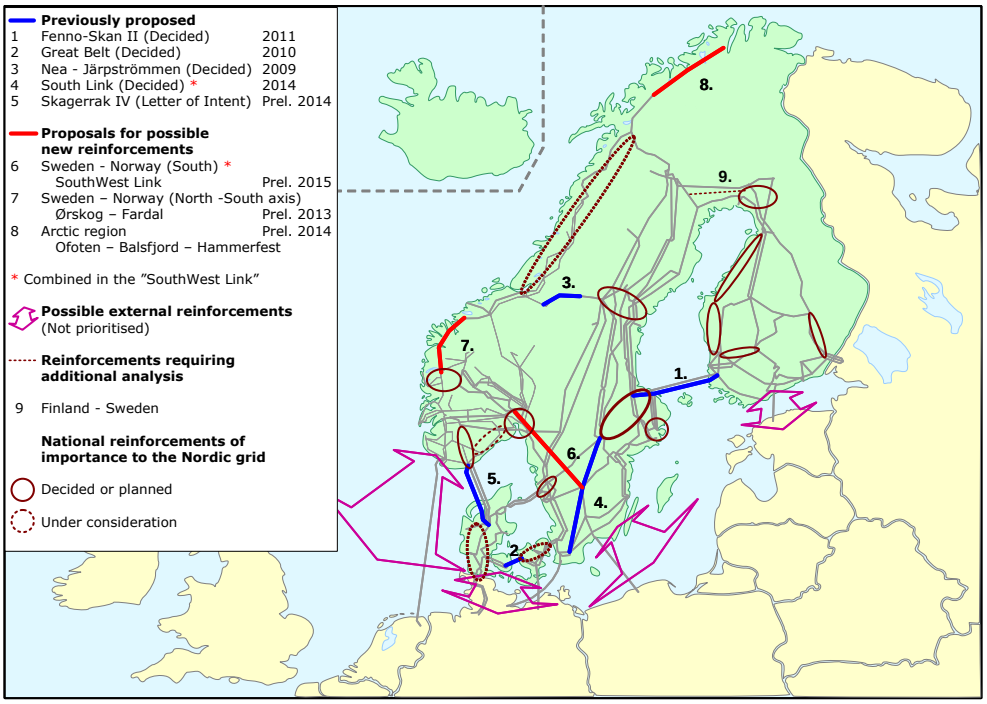


Figure 13 Proposed nordic grid reinforcements in Nordic Grid Master Plan 2008.

3.4 Market-based analysis of interconnections between Nordic, Baltic and Poland areas in 2025 (2009)

An extended, multi-regional, study was performed 2008-2009 by TSOs from Nordel (Svenska Kraftnät and Fingrid), BALTSO (the organisation of TSO's in the Baltic States) and Poland. The aim for this co-operation was the development of a coordinated extension plan of interconnections from the Baltic States to Poland and to the Nordel area in order to satisfy transmission needs between the regions. The study looked at the socio-economic benefit of three specific interconnectors:

- Estonia – Finland
- Lithuania – Poland
- The Baltic states – Sweden

The methodology was similar to the previous Nordel study, using one base scenario for 2015 and three scenarios for 2025 and with benefits calculated from market model analysis.

The overall conclusion was that a solution with all three interconnections was the best solution. The results showed that the capacity provided by the interconnectors would be needed already in the scenario for 2015.

Figure 14 Recommended new interconnectors from 2009 analysis.

3.5 Swedish – Norwegian grid development – Three scenarios (2010)

Statnett and Svenska Kraftnät did a joint study in 2010 which focused in more detail on the common need for reinforcements in the national grids using three different scenarios. Two of these included high and very high respectively levels of additional renewable power generation in the Norwegian/Swedish system. The analysis confirmed the need for the reinforcements identified in the previous studies, with several of them already being implemented, but also showed that further reinforcements are needed to accommodate large new volumes of renewable generation in northern parts of Norway and Sweden. There is a need for reinforcements in the northern and the central parts of the Norwegian/Swedish grid in a north-south direction, as well as reinforcements in the southern part in order to prepare for interconnections to other markets. This is illustrated below in Figure 15.

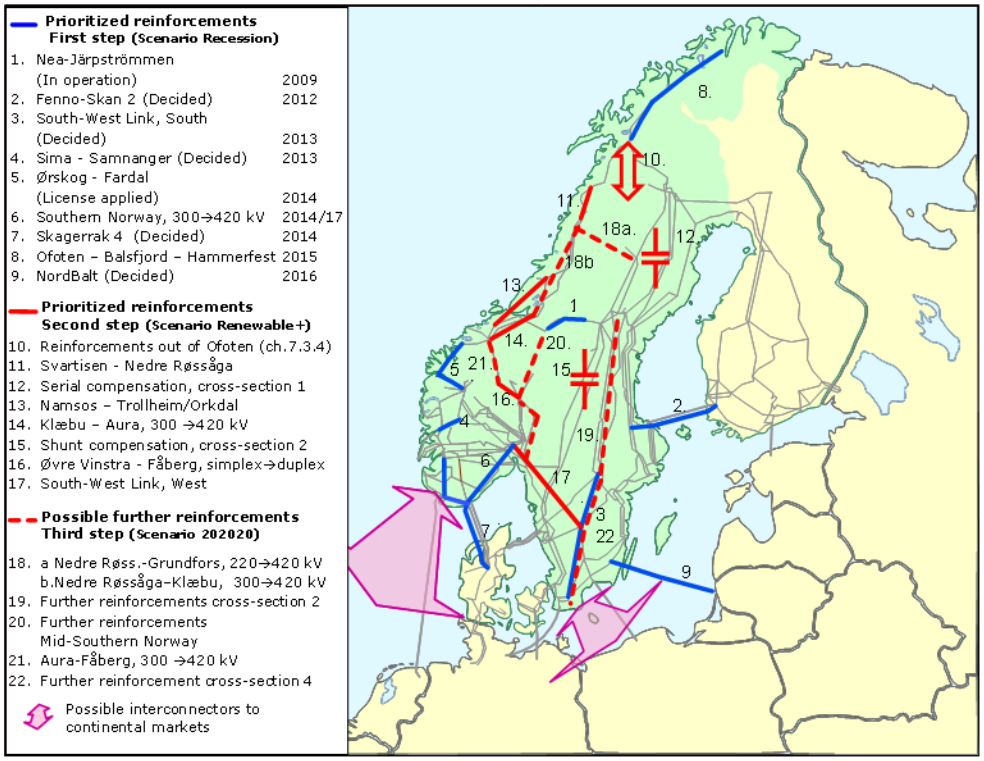


Figure 15 Prioritized reinforcements, Swedish – Norwegian Grid Development 2010.

3.6 Nordic Grid Development Plan 2012

This Nordic Grid Development Plan 2012 described the development of the interconnected Nordic system, including the grid development plans with the neighbouring systems. The Nordic system is geographically large and the transmission capacity is limited due to long distances between production and consumption areas. No new analysis was performed for Nordic Grid Development Plan 2012.

Nordic Grid Development Plan 2012 described the main investment drivers for system development in the Nordic countries as (1) connection of new renewable and conventional generation units, (2) increased market integration inside the Nordic system as well as on its borders and (3) preservation of security of supply as power transfers increase.

As a response to the investment needs, the Nordic TSOs through Nordic Grid Development Plan 2012 presented a number of projects which were considered to have European significance. Most of the projects were already mentioned in previous plans, but some additional investments were presented.
The Nordic Grid Development Plan 2012 showed grid investments between both the Nordic countries and between the Nordic countries and the neighbouring systems (the Baltics, the Continental Europe, and UK).

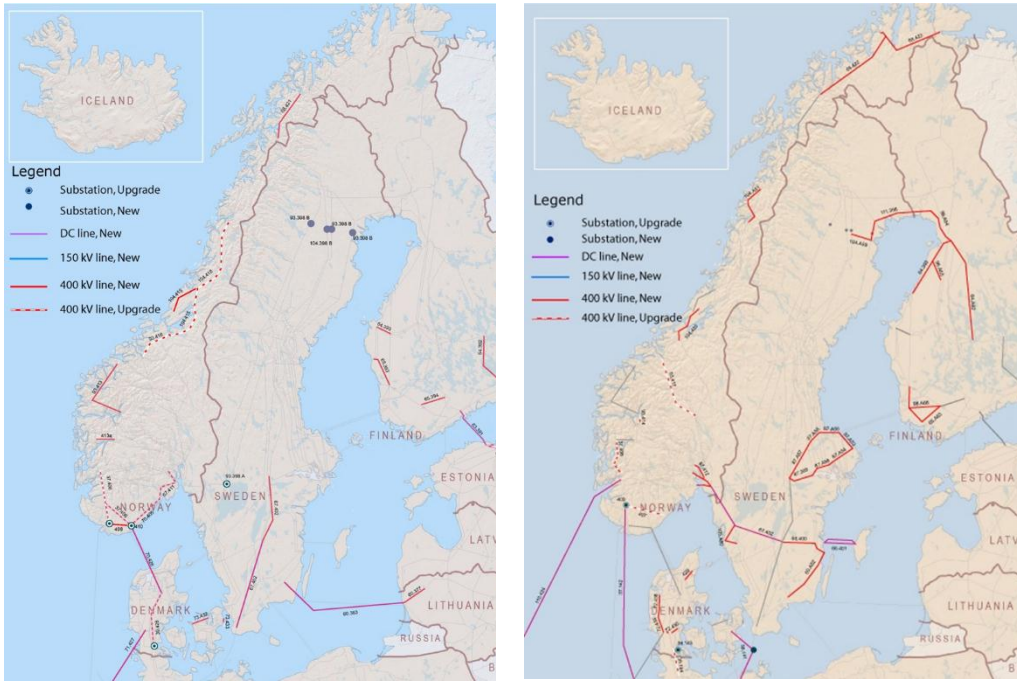


Figure 16 Medium-term and long-term projects presented in Nordic Grid Development Plan 2012.

3.7 Current status

The table below gives a summary of the status of the projects identified in the joint grid planning in the last 10 years. Three out of the first five reinforcements identified in the Priority cross-sections report from 2004 are in operation while the remaining two are under construction with expected commissioning dates in 2014. The reinforcements from the Nordic Grid Master Plan 2008 are also on the way as well as the interconnectors between the Baltic States and the Nordic area.

Reinforcement	Identified in	Description	Commissioning date
Finland-Sweden Fenno-Skan 2	Priority cross-sections 2004	HVDC-link (800 MW) between Finland and Sweden	In operation December 2011
Denmark East-West Great Belt	Priority cross-sections 2004	HVDC-link (600 MW) between Jutland and Zealand in Denmark	In operation September 2010
Norway-Sweden Nea-Järpströmmen	Priority cross-sections 2004	420 kV AC line between mid-Norway and mid Sweden	In operation September 2009
Sweden Cross-section 4 in Sweden	Priority cross-sections 2004	420 kV AC line and HVDC-link (2*720 MW) in Sweden. Northern and Southern part of the 'SouthWestlink'.	Under construction. Expected First quarter 2015
Norway-Denmark Skagerrak 4	Priority cross–sections 2004	HVDC-link (700 MW) Norway-Denmark.	Under construction. Expected December 2014

Reinforcement	Identified in	Description	Commissioning date
Norway-Sweden Hasle cross-section	Nordic Grid Master Plan 2008	HVDC-link (2*720 MW) between Norway and Sweden. Western part of the 'SouthWestlink'.	Project terminated by Statnett and Svenska Kraftnät
Sweden-Norway north-south axis Ørskog-Sogndal	Nordic Grid Master Plan 2008	420 kV AC line between Ørskog and Sogndal in Norway	Under construction. Expected 2016
Arctic region - Ofoten-Balsfjord - Balsfjord-Skaidi-Hammerfest	Nordic Grid Master Plan 2008	420 kV AC line in northern part of Norway. Part 2 is waiting for licence. Expected 6-8 years after this.	- Under construction. Expected 2017 - Expected 2021/22
Estonia-Finland Estlink 2	Multiregional plan 2009	HVDC-link (650 MW) between Estonia and Finland	In operation February 2014
Baltics-Sweden NordBalt	Multiregional plan 2009	HVDC-link (700 MW) between Lithuania and Sweden	Under construction. Expected 2016

Table 2 Current status of projects.

4. Visions of the future

In this chapter the Visions/scenarios used in the Nordic Grid Development Plan are described. The chapter starts with a description of the four scenarios that are used within all the simulations.

4.1 Description of the visions

This section describes qualitatively the scenario approach (called Visions henceforth) used for the preparation of the ENTSO-E's Ten Year Network Development Plan 2014 (TYNDP 2014). Quantitative descriptions of the visions are provided in ENTSO-E's report Scenario Outlook and Adequacy Forecast 2014-2030.

The year 2030 is used as a bridge between the European energy targets for 2020 and 2050.The aim of the '2030 Visions Approach' used for the TYNDP 2014 scenarios should be that the pathway realised in the future falls with a high level of certainty in the range described by the Visions.

The Visions are not forecasts and there is no probability attached to them. In addition, the visions are not optimised scenario (eg no assessment was performed of where the solar development would be the most economically viable). These Visions also have no adequacy analysis associated with them and are based on previous ENTSO-E and regional market studies, public economic analyses and existing European documents.

This is a markedly different concept from that taken for the Scenarios until 2020 used in the TYNDP 2012, which aim to estimate the evolution of parameters under different assumptions, while the 2030 Visions aim to estimate rather extreme scenarios, between which the evolution of parameters is foreseen to occur.

In ENTSO-E's TYNDP-process, which the Nordic Grid Development Plan 2014 is based upon, the four visions are used to assess the project portfolio on the cost-benefit analysis methodology: Two bottom-up visions and two top-down visions. Differences in the high-level assumptions of the Visions are manifested among others in quite different fuel and CO_2 prices sets, in Visions 3 and 4, compared to Visions 1 and 2, resulting in a reversed merit order of gas and coal units.

4.1.1 Regional description of scenarios

Visions 2 and 4 are compiled from a top-down approach; consequently not all national development plans and have been taken into account. It can result in inconsistencies with national plans, but based on the assumptions of top-down Visions, assumptions provide consistency with the vision at European level. Based on these assumptions, regional analyses in conjunction with additional RES generation capacity, Vision 4 have been focused on interconnection capacities between countries and market areas, rather than grid connection solutions of particular units. The Visions vary in range and are interpreted by the TSOs/involved parties in following way:

1. Vision 1 is slow progress and it is also based on national TSO input for less favourable economic and finance conditions based on common guidelines. The Vision 1 is bottom-up vision based on national energy policies and research and development schemes, no evolution in demand response, no commercial break through of electric plug-in vehicles, and a low level of heat pumps. The NPPs are regulated by national policies and no changes on storage facilities. The CO_2 price is low and high primary energy prices prevail.

2. The Vision 2 is money rules vision with more liberalised electricity market conditions in whole Europe but still less favourable economic and finance conditions remain. The Vision 2 is top-down vision which is more slightly adjusted from Vision 1. It is EU top-down view where European focus on energy policies and research and development schemes are applied; electricity demand should be higher as in Vision 1, more favourable conditions for electricity vehicles with flexible charging, NPP developments based on public acceptance and no changes on storage facilities. The CO_2 price is low and the primary energy prices are high.

3. The Vision 3 is bottom-up vision based on national TSO input and reflects national energy policies and research and development schemes as well as favourable economic and finance conditions are expected. Electricity demand should be higher as in Visions 1 and 3, more favourable conditions for electricity vehicles with flexible charging, NPPs developments according national view, and planned decentralised storage. In the Vision 3 low CO_2 prices and low primary energy prices prevail.

4. The Vision 4 is the most ambitious of all four Visions and it focuses on green revolution when RES are expected as base generation, and fossil fuels remain as secondary generation and for keeping a balance in power system. The Vision 4 is prepared by expert team of ENTSO-E and by framework it is a top down. In this Vision very favourable economic and financial conditions are expected, European focus on energy policies and research and development schemes, electricity demand is the highest comparing to other visions, very favourable conditions for electricity vehicles (with flexible charging and generation), much more heat pumps implemented, developments of NPPs by public acceptance, new centralised hydro storage with decentralised storage. In terms of CO_2 prices, it has assumed high (93 Euro/t) but at the same time low primary energy prices.

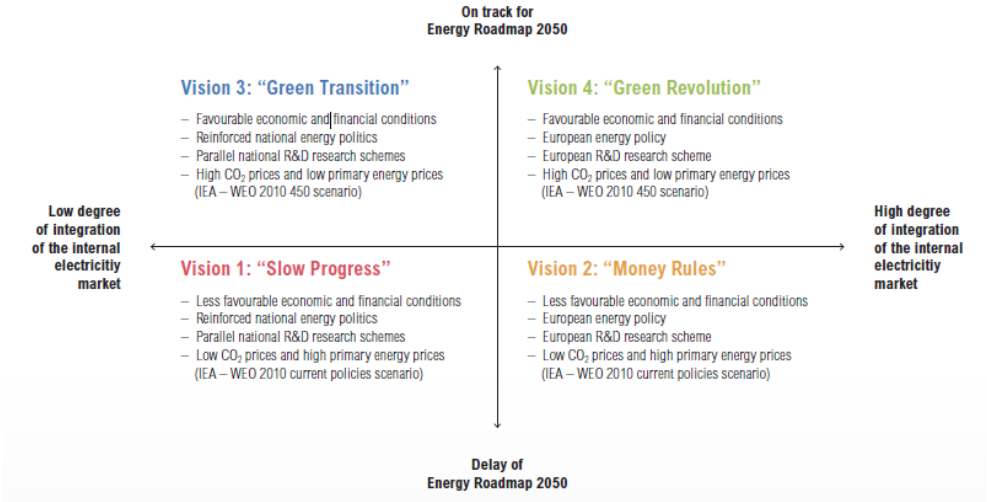


Figure 17 Overview of the political and economic frameworks of the four Visions.

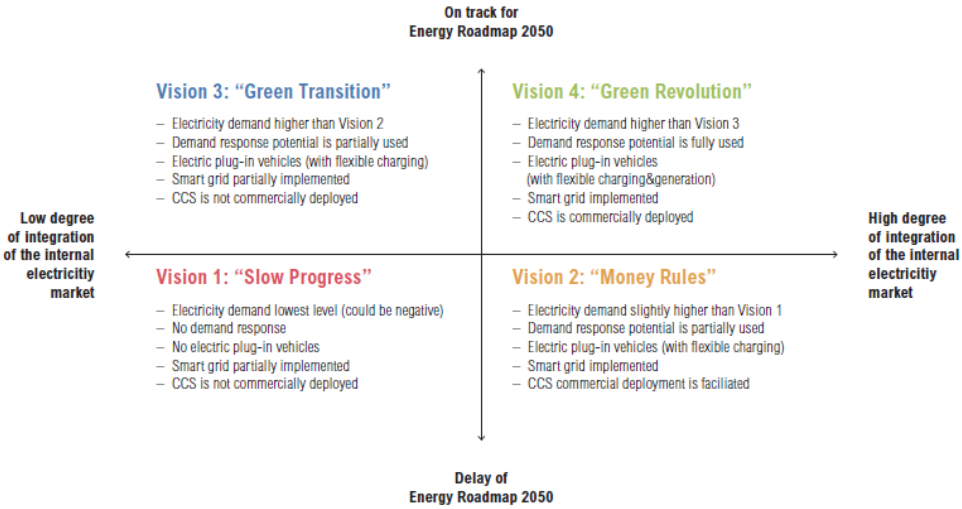


Figure 18 Overview of the generation and load frameworks of the four Visions.

4.1.2 Generation, consumption in Nordic Region

The demand is rising from Vision 1 till Vision 4. As Vision 1 has the least favourable economic growth conditions of all the visions, the demand is at the lowest level in vision 1 and is for the whole Nordic region around 410 TWh. In Vision 4 the demand reaches its peak, and is expected to reach more than 460 TWh due to expected better economic conditions in general and increased demand for heat pumps and electric vehicles. The assumed difference in consumption between Vision 1 and Vision 4 is more than 50 TWh.

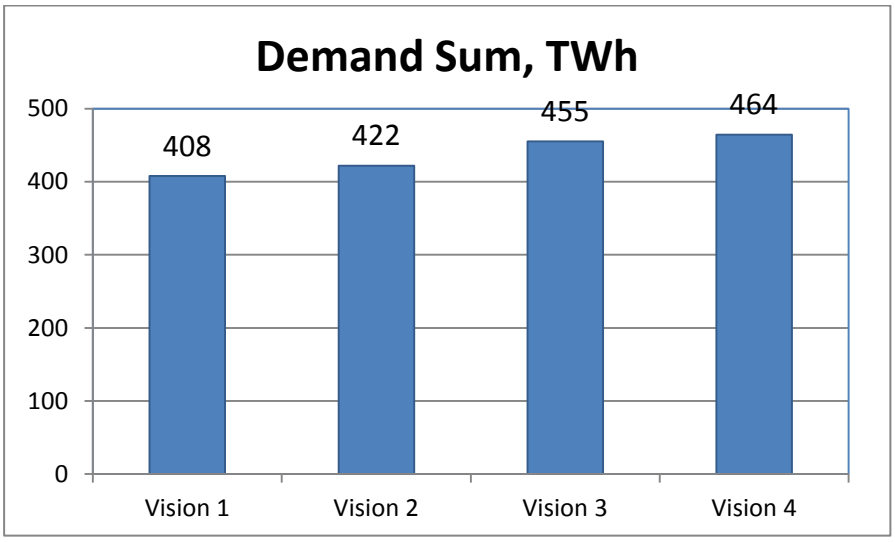


Figure 19 The demand in the Nordic Area, measured in TWh.

Figure 20 shows the difference between installed capacities in the different Visions in the Nordic countries. In general the green Visions lead to more renewables in all the countries. Additional in Vision 4 a huge amount of pump storage (14 GW) is assumed installed in Norway. The generation capacity mix in a future European power system is dependent on the incentives applied by central and local authorities. With the right incentives like subsidies and price of carbon emissions, it is possible to achieve a certain direction in the development of power generation facilities in Europe. The four visions are made to span the possible future development and analyse the consequences of these development trends. The demand for the four visions is shown in Figure 19. Due to different assumed development trends, the demand will be different in the different visions. The total generating capacity and generation mix will reflect the anticipated future for each vision.

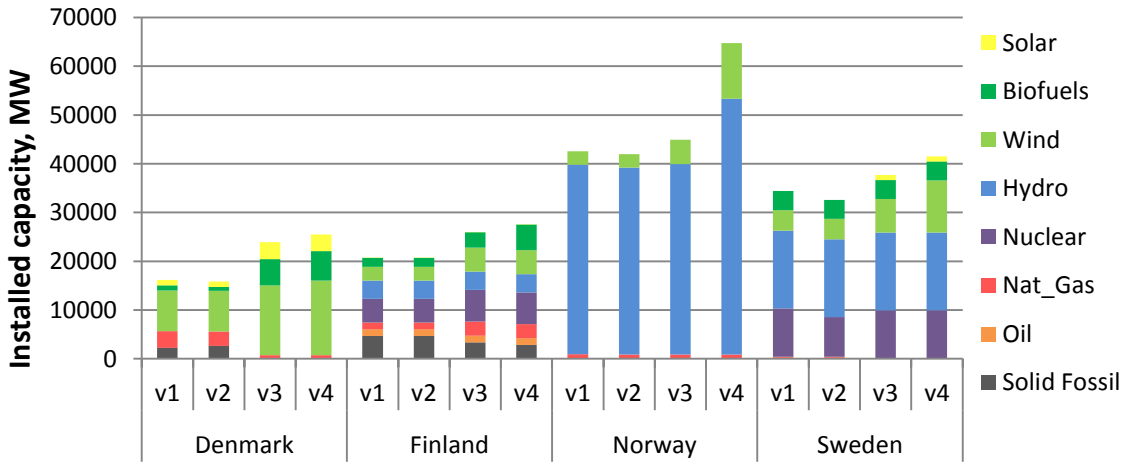


Figure 20 Installed generation capacity in the Nordic Area in Visions 1, 2, 3 and 4.

4.1.3 Inter-area transmission capacities

The new projects of the TYNDP 2014 that are being analysed are given below on the map. There are two types of assessed projects: ones that are included into the reference case and assessed with the TOOT[1] approach and others that are analysed as additional projects to the reference case with the PINT[2] approach. Reference case includes all the TYNDP 2012 projects (including reassessed projects) except cancelled ones. Additionally, new project candidates were included. The map below shows transmission capacity situation of 2030 with all capacities in the reference case. Reference capacities between price areas include both existing interconnections, projects from TYNDP 2012 and possible new project candidates.

Capacity increases of immature and alternative projects are not included into reference case, but analysed separately.

Figure 21 Inter-area transmission capacities used for Visions analyses and project assessments.

1 TOOT: ”Take One Out at the Time”. An approach where all project candidates are added into the reference case and assessed by taking one project at the time out and looking at the differences in the assessment indicators. This can be considered a conservative approach to assessing the value of a project.

2 PINT: ”Put one IN at the Time”. An approach where the reference case is without all the project candidates and where one is put in at the time and the difference on assessment indicators is measured. This will overestimate the value of a project in the long term.

5. Drivers for grid investment in the Nordic countries and Market study results

The following chapter lays out the main drivers for grid development in the present years and links this to the system as it is today. A holistic look across all four visions of market flow patterns in the grid is presented before a look into the detailed simulation results of each vision is given. Finally, the results of the four visions are compared and a deeper look into bottelnecks in the Nordic grid is presented by way of cost differences in the different market nodes in the Nordic system.

5.1 Present situation

The Nordic region comprises four countries in two separate synchronous systems: Eastern Denmark, Finland, Norway and Sweden comprise the Nordic synchronous system, and Denmark West is synchronously connected to the Continental European system. A total of nine subsea HVDC cables currently connect the Nordic system to the Continental system and two subsea HVDC cables connect the Baltic and Nordic systems. The Nordic system is connected to Russia via DC back-to-back station and some Russian generators are connected to the Nordic system by AC lines. The Nordic system is already a very integrated electricity market and as Figure 22 shows, the system has relatively high transfer capacities (in comparison to maximum electricity load) to neighbouring countries.

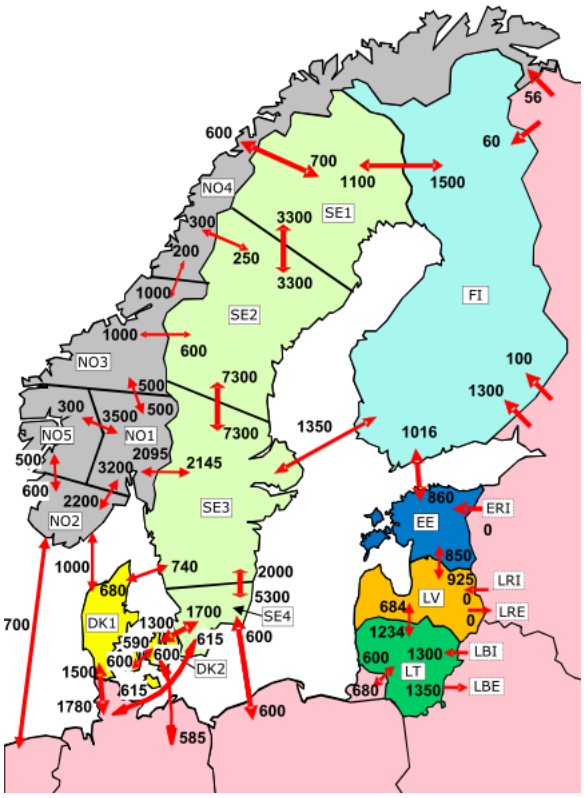


Figure 22 The three synchronous systems of Baltic Sea region, maximum NTC valid from February 2014.

NTC values for the same equipment change under different conditions, for example the topology of the network or the load pattern at the given point in time that the study is conducted.

The total annual consumption in the Nordic region is approximately 390 TWh, excluding Iceland. The peak load is much higher in winter than in summer due to cold winters and large amounts of electric heating. Main consumption areas are located in the southern parts of the Nordic system. Consumption and production of electricity in the Nordic countries are shown in Figure 23 andFigure 24.

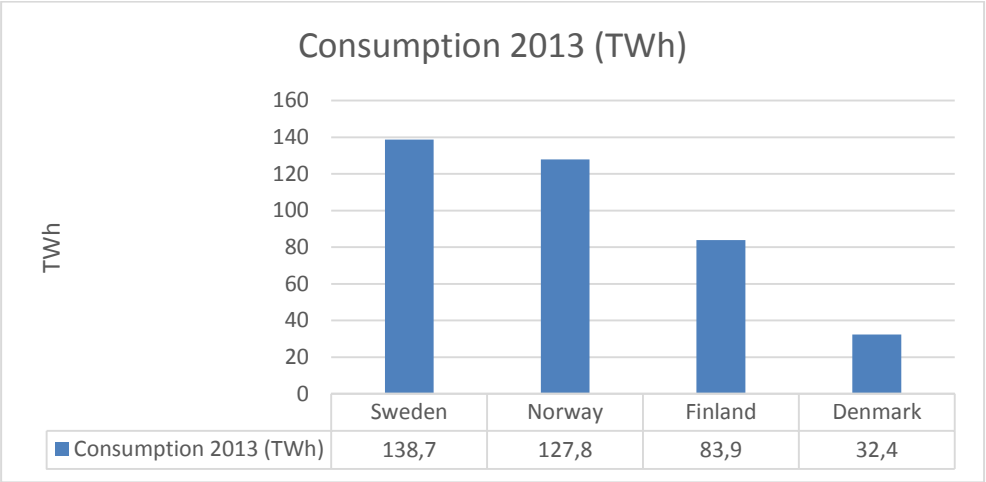


Figure 23 Consumption of electricity in the Nordic countries 2013.

The Nordic power system is dominated by hydropower with most of the hydropower plants located in Norway and northern Sweden. Denmark stands out with a high share of wind power. The energy-constrained Nordic hydropower system has a very flat daily price structure compared to the capacity-constrained thermal systems. The difference in energy balance of countries in the region between wet and dry year is significant. During an average year, Finland has a large energy deficit while other countries in the region are more balanced. Finland is dependent on import during peak load hours throughout the year while Denmark is dependent on import only during the summer months where significant amounts of thermal generation capacity is out for maintenance, as seen in the 2014 Summer Outlook from ENTSO-E. However, both countries have grid connections to several neighbouring countries which will ensure the security of supply.

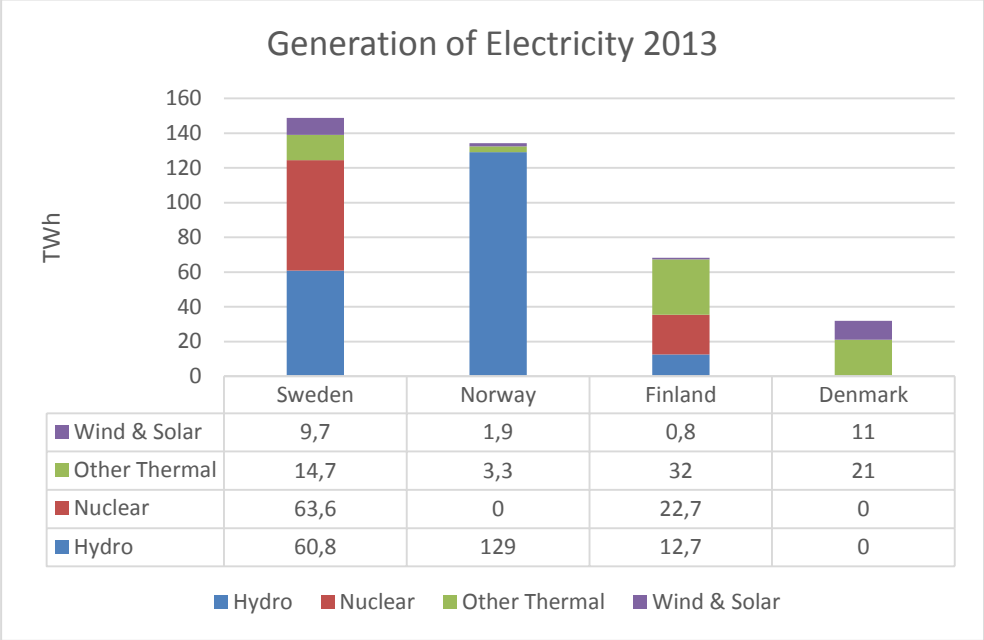


Figure 24 Generation of electricity from different sources in Nordic Region countries in 2013.

The main power flow is during a typical day from the hydro power plants in northern Scandinavia towards the south, all the way to Central Europe. In general during the night, flows are from Central Europe and Baltic States to the Nordic countries.

5.2 Drivers of system development now and in the future

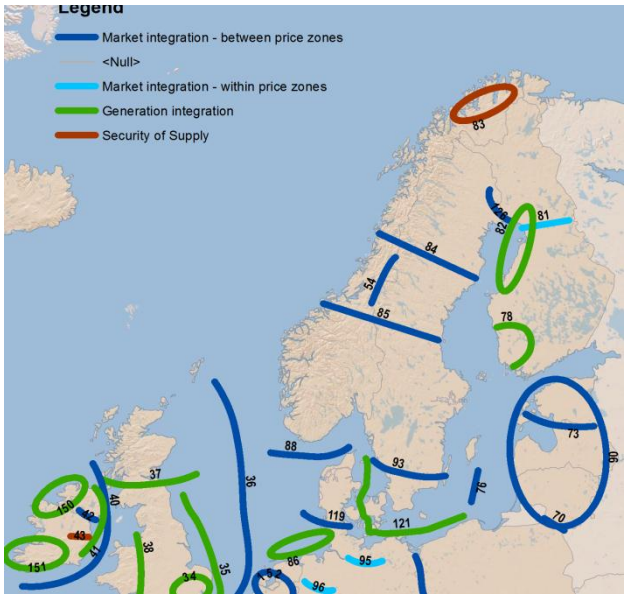


Figure 25 Main possible bottlenecks by 2030.

The three main drivers for system development in the Nordic region are market integration, integration of renewables and conventional (nuclear and other

thermal) generation as well as security of supply. These drivers are followed by the refurbishment of aging equipment and environmental issues. One of the biggest challenges with the main drivers is the considerable uncertainty with respect to generation investments. On the EU-Russian border there is also uncertainty regarding the market development. Until early 2010's, the direction of flow has been steady from Russia, since Russian prices have been clearly below prices in the Nordic region, but in a future with more equal prices due to more similar generation portfolios, there may be less import or even export at times when the electricity price is higher in Russia or low in Nordic or Baltic Sea region. In the south-east part of the region, the integration of Baltic countries with the Nordic and European electricity market can also have an impact on the border transfer between Russia and the neighbouring countries.

5.2.1 Market integration

In the medium term, market integration is a key driver for grid investments in the Nordic region. More capacity is needed between the Baltic States and the European energy market to thoroughly integrate the Baltic States with the Nordic and European energy market. While a strong integration already exists between the Nordic countries, further integration is required in order to fully utilize the benefits of the countries' diverse generation type portfolios.

Bottlenecks currently still exist between the areas dominated by hydropower in Norway and northern Sweden and the areas dominated by thermal generation in southern Finland, southern Sweden and Denmark.
More capacity between Nordic and Continental Europe is vital to serve the expected change in transmission patterns due to the increase in wind power in Continental Europe and the change in power balance in Germany.

In the ENTSO-E Regional Group Baltic Sea, an additional vision with a considerable amount of new renewable production and hydro pumping power to match the need for fast regulation has been studied. In such an environment, the inter-area transmission capacities will play a crucial role, not only for transfer of energy, but also for making regulating power available for the whole system. New wind power must be built where there are possible available areas, many times offshore, and this will often be far from the consumption centres, triggering need for new infrastructure. With a high CO_2 price, energy production from coal-fired power plants is substituted by renewable production with low variable production cost. Price differences are generally higher than in other studied scenarios with less renewables and lower CO_2 price (Vision 1 and 2) and the socio-economic benefit of new transmission capacity is also higher. Ancillary services must be available throughout the interconnected market areas and this puts strain on transmission capacities that are already highly utilised for energy transfer in Vision 4. To have a functioning and integrated market both for energy and ancillary services, transmission infrastructure must be dimensioned accordingly.

5.2.2 RES and conventional generation integration

In the long-term, change in the generation mix in the Baltic Sea region drives the system development to a large extent. It is both due to integrating the renewables in relatively remote locations away from the consumption centres and due to enabling the usage of Nordic hydropower to supply Nordic surplus to central Europe when wind power is not generated and absorbing the surplus by the wind power when there is excess of it in Northern central Europe.

New wind power plants are planned to be built almost all around the region, but mainly concentrating on the coastal areas, offshore and the highlands in the northern part of the region. New small-scale hydro generation is planned to be constructed particularly in Norway. The new wind and hydro generation in the northern areas which already have a high surplus of energy requires a strengthening of north-south connections in Sweden, Norway and Finland.

In Finland there are plans and decisions-in-principle to build two new large nuclear power units, and in Sweden there are plans to replace and/or upgrade the existing aging nuclear power units.

5.2.3 Security of supply

Security of Supply is a driving force for grid investments in the Arctic region, especially in the northern-most part of Norway due to increased consumption of the oil industry and new mining sites. The area has weak security of supply even today.

In the Nordic countries, the capacity of wind generation is expected to rise, whilst conventional generating methods are expected to decrease, meaning that security of supply would become a critical issue without the planned transmission investments.

There are also some restricted areas in the region where investments are needed to secure the supply especially when old assets are being dismantled.

5.3 Bulk power flows across the four visions in 2030

The four Visions' market simulation results deliver the main flow directions for each of the Visions. These main flow directions coupled with their order of size is refered to as bulk power flows. Given that the aim of having 4 visions for the future is to test the robustness of grid infrastructure project candidates, it is interesting to compare the vision flows in order to asses whether the suggested grid actually has the intended function.

Vision 1 and 2 - Large East-West flows; North to South flows

In total, the Baltic Sea Region is an exporting region in both Visions 1 and 2. The largest exporting countries are Sweden, Poland, Finland and Denmark. Small export also comes from Norway and Latvia. The dominant energy flows are north-south directional, towards continental Europe and Great Britain. Energy flows are shown on the figure below.

Vision 3 and 4 - Nordic surplus exported to Central Europe; large north-south flows: bidirectional east-west flows

The main transmission corridor is through Nordic countries to Central Europe, but also corridor through Baltic countries and Poland serve as an additional support for north-south flows.

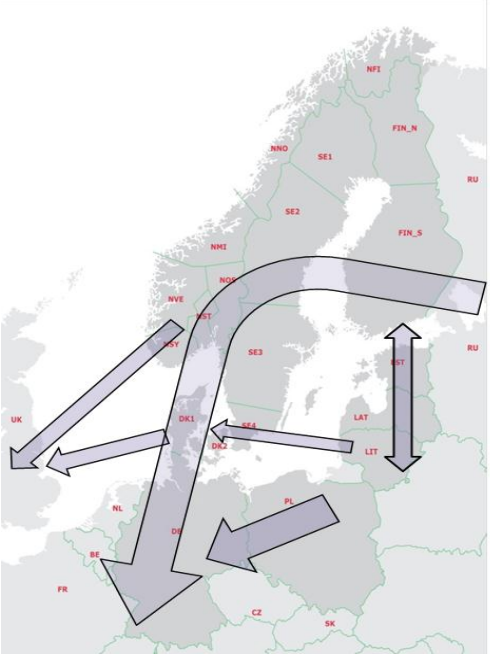


Figure 26 Bulk power flows in vision 1+2.

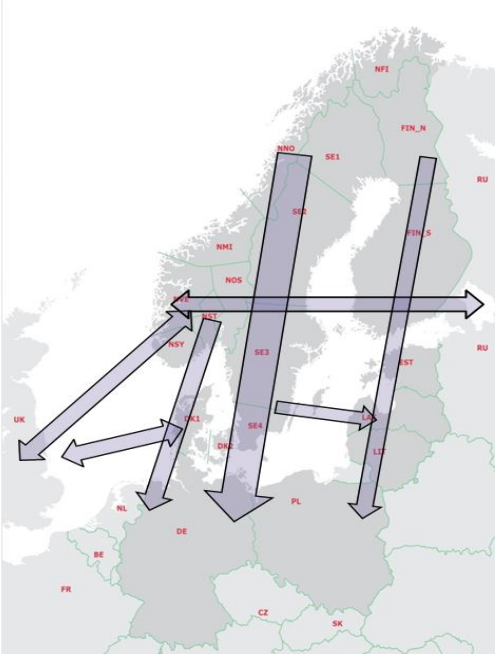


Figure 27 Bulk power flows in Vision 3+4 (RGNS Regional Investment Plan).

Duration curves of the main regional cross-sections are shown on figures below. These show the duration curves in the different visions between Nordic area and Continental Europe and between Nordic area and Baltic area.

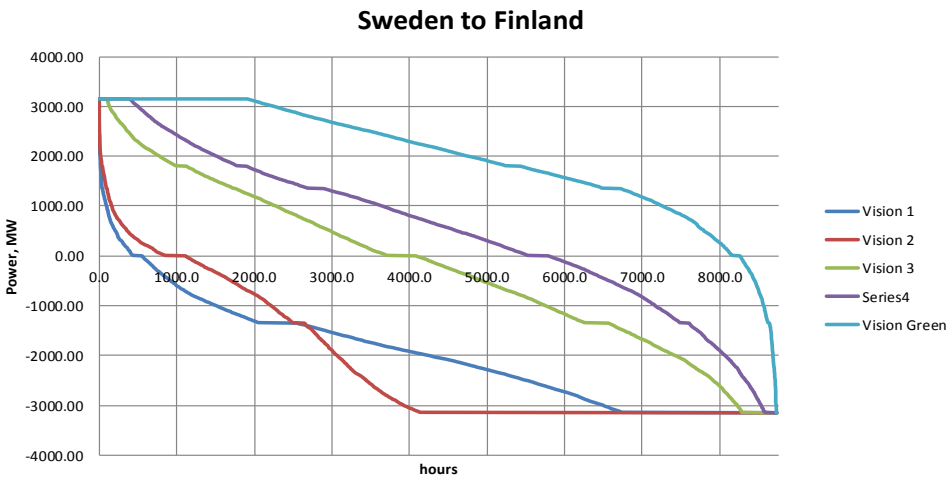


Figure 28 Duration curves for flows between Sweden and Finland. Vision Green is the baltic green vision which is additional to the 4 ENTSO-E visions. (RGNS Regional investment plan).

As seen from the bulk power flow analysis (see Figure 28) electrical cross-section between Sweden and Finland displays a wide range of utilisation patterns over the range of Visions the cross section was studied in. The most flexible utilisation of the cross section is to be found in Vision 3 and Vision 4 – in these visions, the cross section between Finland and Sweden serves both importing and exporting needs. On the other hand, in these visions characterised by rather extreme relocation of generating units and the increased role of distributed generation in the region, the electrical cross section between Sweden and Finland seldom gets used to its full capacity since generation (especially in Finland) has gone closer to consumer in the form of distributed, and RES, generation developments.

The Baltic Sea Green Vision is characterised by decreased utilisation of nuclear and thermal power generation units in Finland. In this case, as it can be seen from duration curve (Figure 28, light blue graph) Finland has become a large energy importer and the electrical cross section between Finland and Sweden is operating predominantly in direction of Sweden to Finland and the cross section is utilised up to its maximum capacity more than one third of the time.

Vision 1 and Vision 2 are characterised by more conservative and traditional generation development based on the common data collection guidelines. In these scenarios Finland is a strong energy exporting country, which is especially accented in the results of Vision 2 where the cross section Sweden – Finland is utilised to its maximum capacity in direction to Sweden in more than 50% of the simulated time.

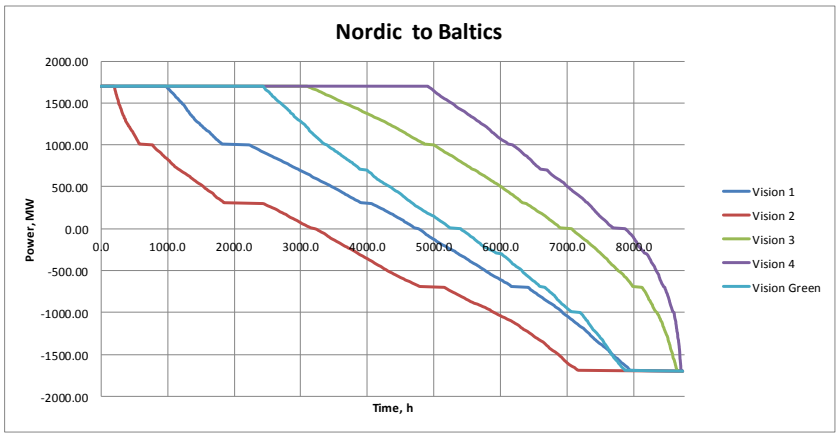


Figure 29 Duration curve for flow from the Nordic Area to the Baltics (RGNS Regional Investment Plan).

Electrical cross section between Nordic countries and Baltics, Figure 29, is comprised exclusively of controllable DC links. This controllability can be observed in the duration curves with cross section being utilised in both directions (import and export) depending on energy market situations and also in reasonable small amount of operation time at maximum capacity. Exceptions to this rule are again being extremes of planning simulations – Vision 3 and Vision 4 where cheap RES energy of Nordics is being rushed to Central Europe on all possible energy transfer routes, including DC links towards Baltics. Therefore, in these simulations, one can observe predominant direction of flow away from Nordics and maximum link capacity utilisation time exceeding 5000 simulated hours out of 8000.

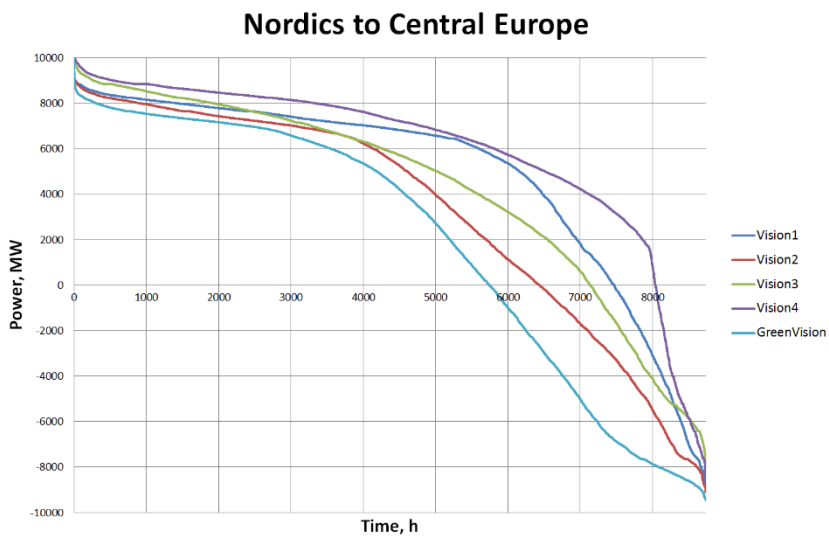


Figure 30 Duration curves for flow from the Nordics to Central Europe (RGNS Regional Investment Plan).

Interconnection between Nordics and Central Europe, Figure 30, is comprised predominantly of controllable DC links, but unlike in the case of Baltics to Nordics interconnection, this cross section has a much larger capacity and is interconnecting different countries/power systems with wide variety of dominating energy production types and demand patterns thus providing for a smoother overall utilisation pattern of the cross section in general. Therefore, one can observe very uniform cross section utilisation patterns regardless of the modelled Visions. But of course Vision 4 is the most extreme case of export from Nordics to Central Europe, with total cross section in the export mode for more than 85% of the time. The sensitivity, Green Vision, being more balanced with regards to energy system topology (RES vs. thermal generation capacity), the cross section operates equally in export and import modes during the year. The most obvious quality of the combined cross section between Nordics and Central Europe is its adequacy to current and foreseeable power transfer tasks; however, individually some of the DC links in the combined cross section are still heavily utilised and might require strengthening in the future.

5.4 Market study results of different visions

This section gives an overview of generation, balances and price-differences in the different visions. The results are fully based on the regional analyses in ENTSO-E's Regional Group Baltic Sea.

The Nordic countries have in general an interesting generation mix that makes it favourable to build interconnectors to Central Europe. A large amount of hydropower with variable annual inflow will give a large energy surplus in some years and deficit in other years. To utilise the flexibility of hydropower systems in cooperation with thermal/wind/sun based systems in an optimal way, it is important to have enough transmission capacity between the areas.

5.4.1 Market Study Results of Vision 1

The Vision 1 dataset is originally submitted to ENTSO-E by all national TSO’s applying a set of guidelines developed by ENTSO-E to ensure consistency. It reflects a slow progress in energy system development with less favourable economic and financial conditions.

In Vision 1 there is a relevantly strong generation share from thermal and nuclear power plants. RES increase is assumed to be rather modest than quick, compared to Vision 4. The biggest RES contribution comes from hydropower, then from wind. As can be seen, Norway, Sweden and Finland have a considerable amount of hydropower generation.

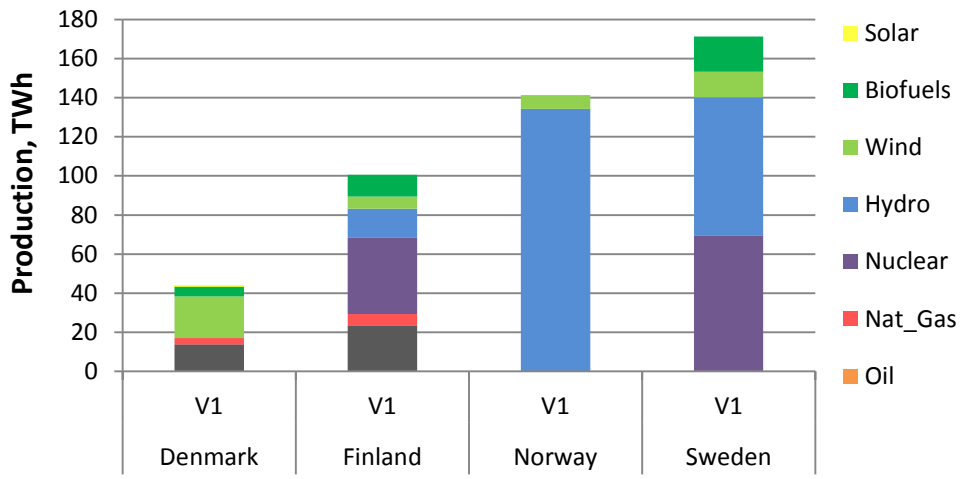


Figure 31 Vision 1 annual generation (TWh/year).

Figure 32 shows the simulated average cost-difference in the Nordic and neighbouring countries in Vision 1. The figure shows the yearly average costs per country and the average marginal cost difference between countries based on hourly absolute price difference. The figure shows that the largest cost-differences are between the Nordic countries and Central Europe. But a large cost differences can also be found towards Poland and the Baltics.

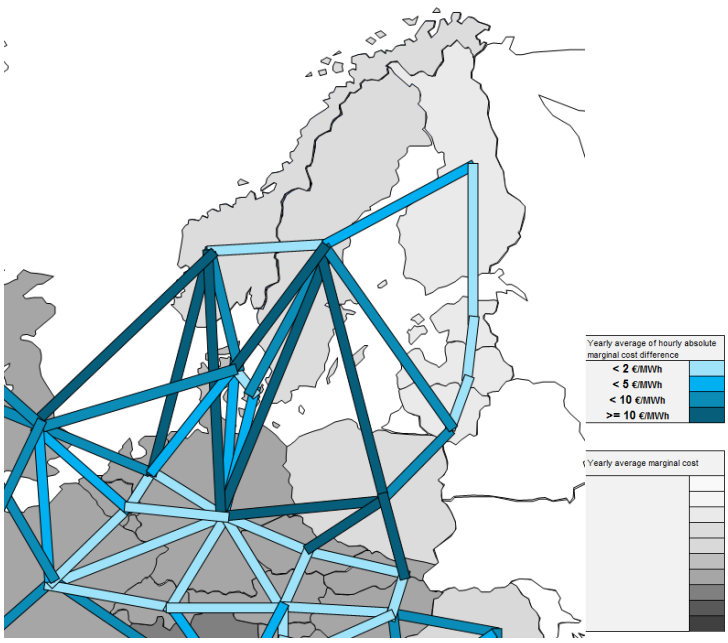


Figure 32 Yearly average marginal cost difference in Vision 1.

5.4.2 Market study results of Vision 2

The generation share in Vision 2 is quite equal to the one in Vision 1. In general, due to precondition for Vision 2 that assumes hard coal is preferred to gas and economic and financial conditions are less favourable than in Visions 3 and 4, there are no big changes between Vision 1 and Vision 2. Thus, increase of demand in Vision 2 combined with decommissioning of some Swedish nuclear power plants causes the increase of generation from thermal power plants.

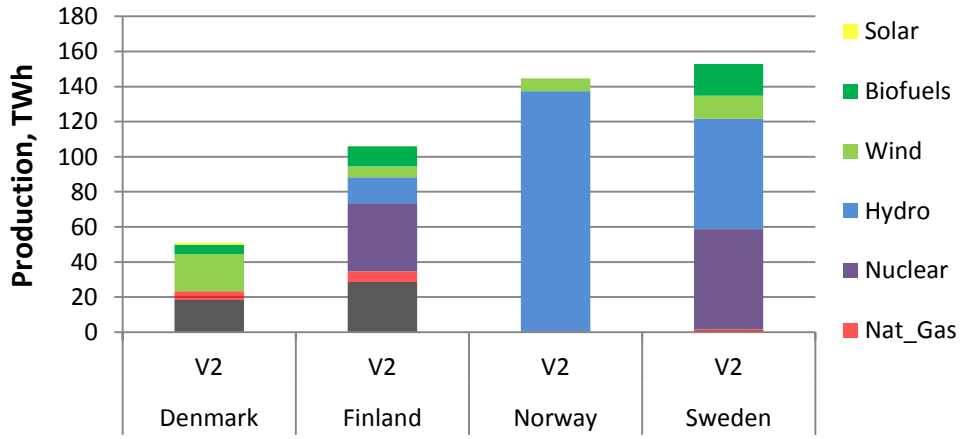


Figure 33 Vision 2 annual generation in TWh/year.

Figure 34 shows the simulated average cost-difference in the Nordic and neighbouring countries in Vision 2. The figure shows the yearly average marginal cost difference between countries and the average marginal cost difference based on hourly absolute price difference. The figure shows that in general, the cost-differences are lower than in the other visions. The reason for that is that the scenario assumes a more integrated Europe with higher transfer capacities.

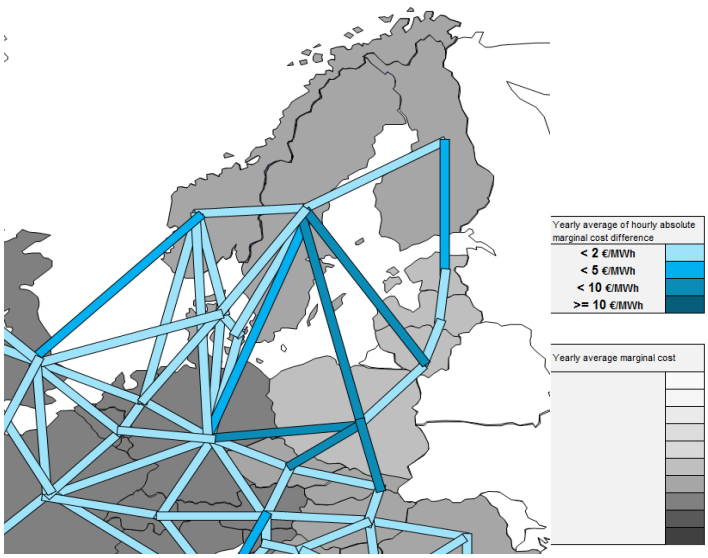


Figure 34 Yearly average marginal cost difference in Vision 2.

5.4.3 Market study results of Vision 3

In Vision 3 the generation share from renewables are much higher than in Vision 1 and 2. This leads to a reduction of thermal power plant generation. However, there is an increase of generation from gas power plants compared to Vision 1 and 2. The biggest RES contribution comes from wind, hydro and biomass. This based on the fact that CO_2 prices are rising which leads to a generation shift from coal to gas, as well as from thermal to renewables.

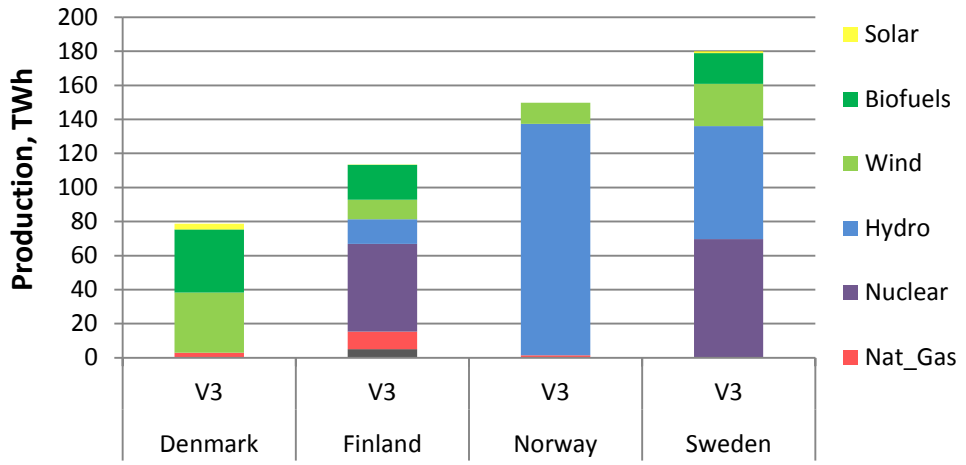


Figure 35 Vision 3 annual generation in Twh/Year.

Figure 36 shows the simulated average cost-difference in the Nordic and neighbouring countries in Vision 3. The figure shows the yearly average marginal cost per country and the average marginal cost difference based on hourly absolute price difference. The figure shows that the largest cost differences are between the Nordic countries and Central Europe. In general, the high CO_2 prices lead to a high power cost in thermal areas like Germany and Poland. This leads to very high cost differences between the Nordics and Germany/Poland.

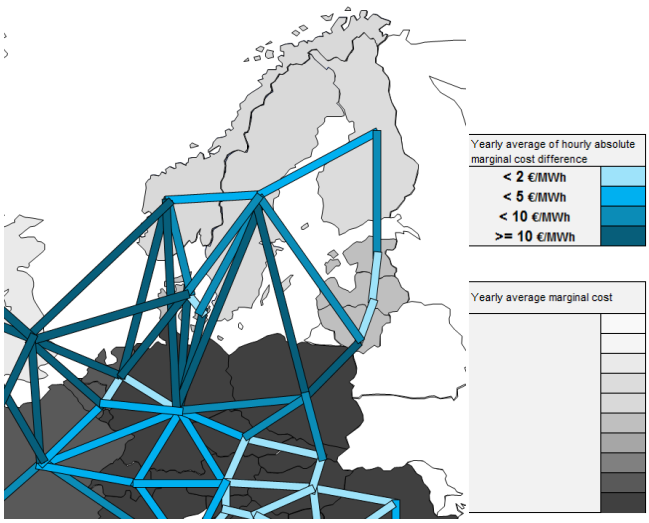


Figure 36 Yearly average marginal cost difference in Vision 3.

5.4.4 Market study results of Vision 4

In Vision 4 the generation share from renewables is even higher than in Vision 3. This leads to a reduction of thermal power generation. The biggest RES contribution comes from wind, hydro and biomass. This is based on the fact that CO_2 prices are rising which leads to a generation shift from coal to gas, as well as from thermal to renewables compared to vision 1 and 2. In Norway there is also assumed a large development in pump storages, but based on low price difference between day and night, the utilisation of the pump storage is low.

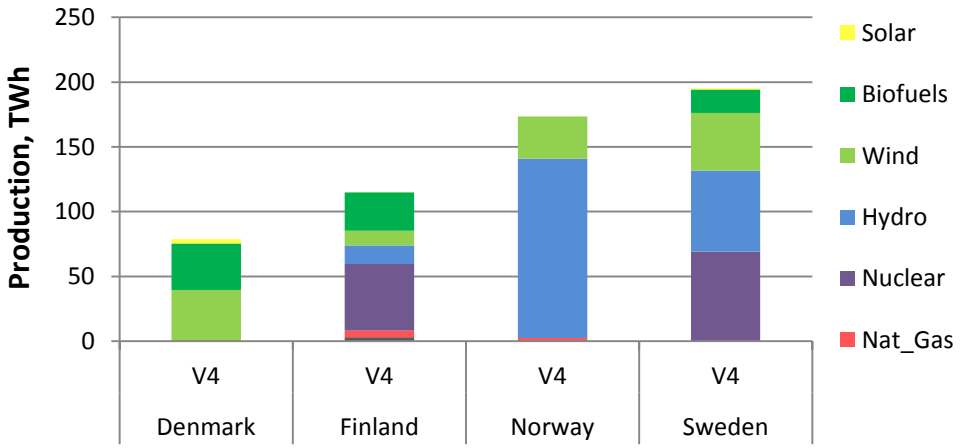


Figure 37 Annual generation in TWh/year.

Figure 38 shows the simulated average cost difference in the Nordic and neighbouring countries in Vision 4. The figure shows the yearly average marginal cost per country and the average marginal cost difference based on hourly absolute cost difference. The figure shows that the largest cost differences are between the Nordic countries and Central Europe. In general, the high CO_2 prices lead to increased power cost in thermal areas. On the other side, the huge amount of renewables leads to decreased costs.

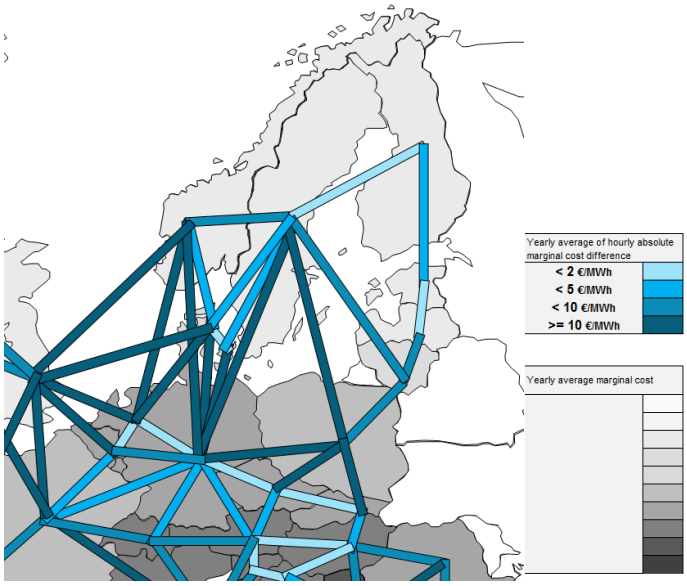


Figure 38 Yearly average marginal cost difference in vision 4.

5.5 Comparison of the 2030 visions

5.5.1 Generation

The Nordic countries have a positive yearly energy balance, but due to seasonal and yearly variations in inflow, the power flow varies considerably between summer and winter and between different hydrological years. In addition to today's balance variations, the expected consumption growth will cause longer periods with negative balance and increased need for grid capacity to ensure secure of supply. With an increased yearly power surplus in a 2030 scenario, today's exchange trend from all countries will be enhanced. This applies especially for the summer period due to high level of non-flexible hydro in combination with reduced consumption. Numerous interconnectors also lead to periods with major import to the Nordic region when the prices on the European continent are low. This results in low generation from hydropower and northward flow in the entire system. Increased industry consumption and petroleum in the North can provide northbound flow even from central Norway to the North. The consequence of the increased HVDC capacity will result in fewer hours with maximum utilisation of the exchange-capacity as the flexibility in the hydropower system is challenged.

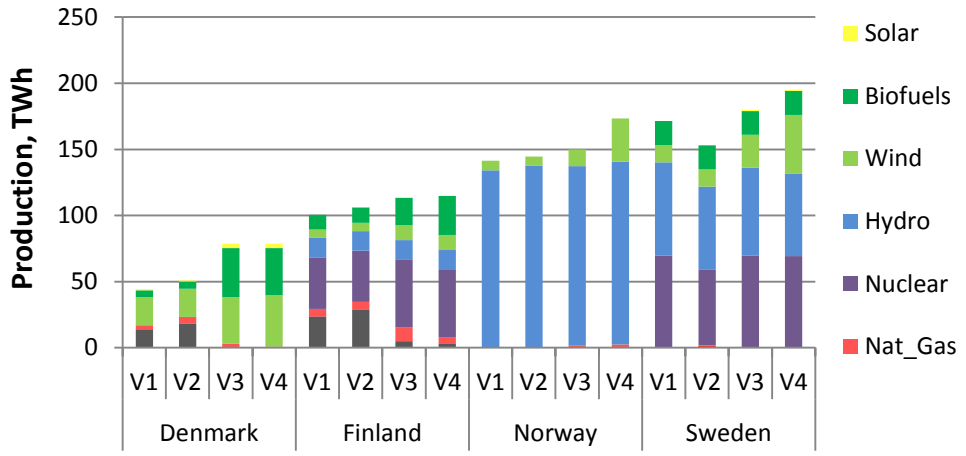


Figure 39 Electricity production in Nordic countries by source type for the 4 different Visions.

Vision 4 is a green vision with a considerable amount of new renewable production and hydro pumping power to match the need for fast regulation. In such an environment, the inter-area transmission capacities will play a crucial role, not only for transfer of energy but also for making regulating power available for the whole system. New wind power must be built where there are possible available areas, many times offshore, and this may be far from the consumption or the market. With a high CO_2 price, energy production from coal fired thermal power plants is substituted by renewable production with low variable production cost. Price differences are generally higher than in Vision 1 and the socio-economic benefit of new transmission capacity is also higher. Auxiliary services must be available throughout the interconnected market areas and this put strain on transmission capacities that are already highly utilized for energy transfer in Vision 4.

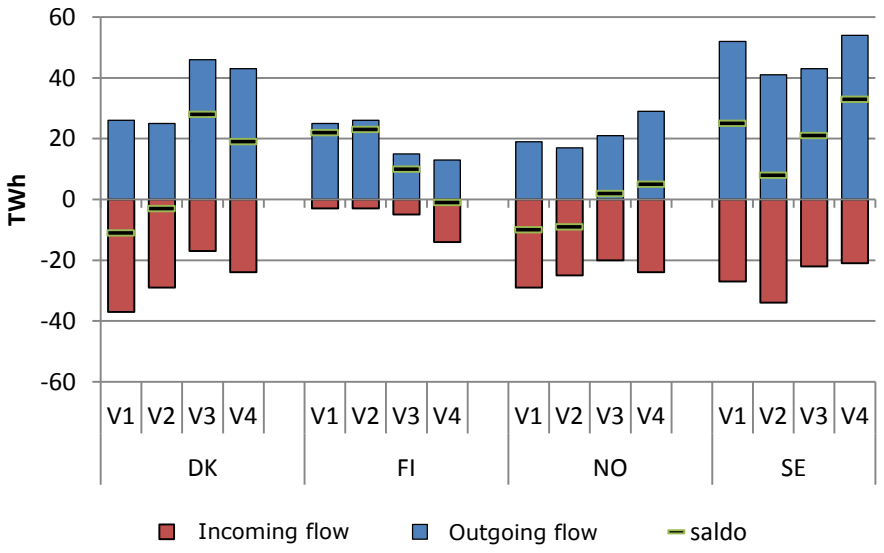
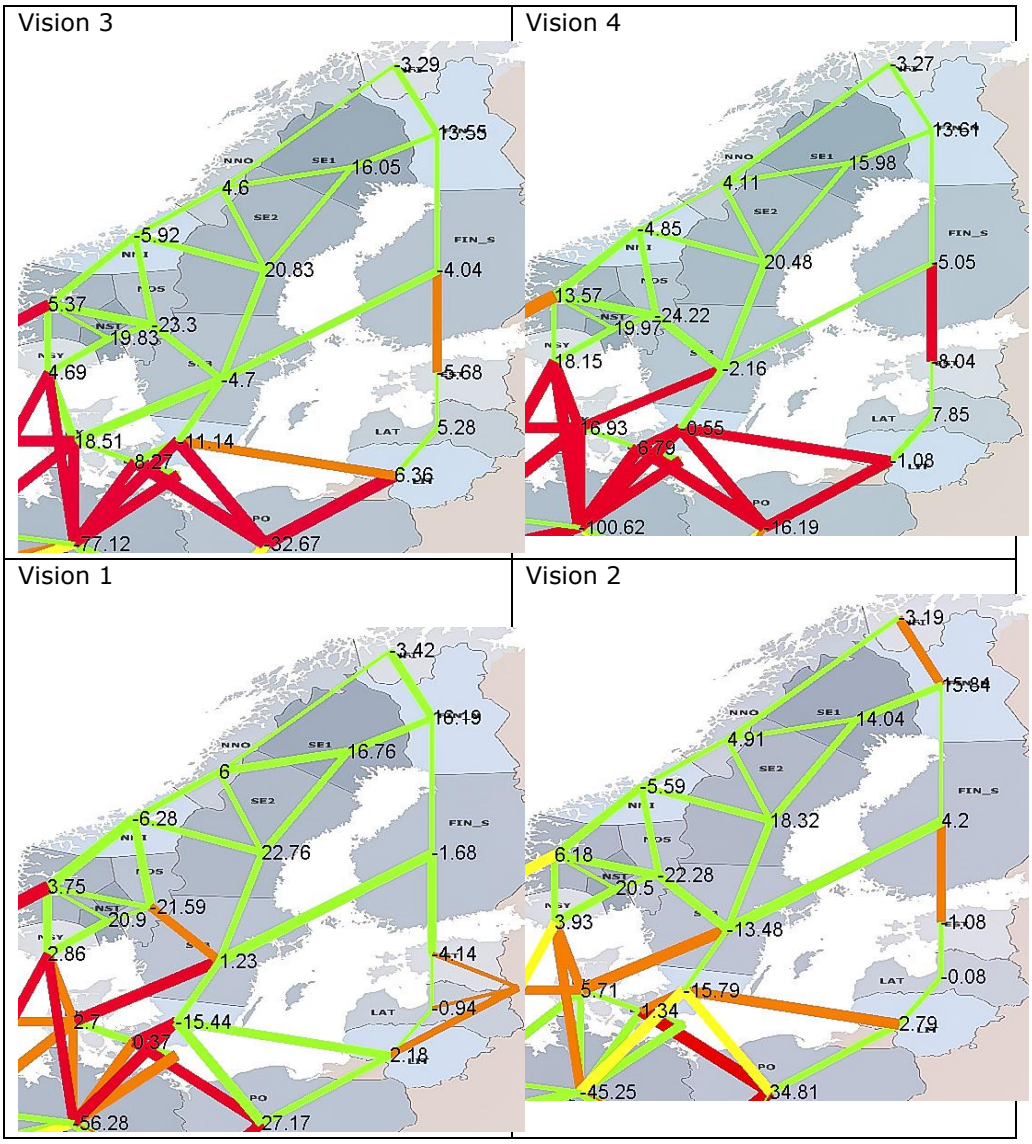


Figure 40 Annual inter-area flows in Nordic countries for different visions. A positive value is corresponding to total outgoing flows and negative value to total incoming flows.

5.5.2 Bottlenecks

The largest bottlenecks appear on boundaries between Scandinavia and Central Europe and North – south flows from north Scandinavia to southern Scandinavia, where interconnectors are loaded in range of 80-90%. Also interconnections from Baltics to Scandinavia are heavily utilized, close to 70%. Also the congested hour's results follow the same trend with relative loading correspondingly. To illustrate the most heavily loaded interconnectors, duration curve figures are given in next chapter.

According to the results, the most utilized interconnectors are between Scandinavia and Continental Europe, Baltics and Nordics or Central Europe and cross-section, north to south of Scandinavia and Finland-Sweden.



Legend:
Areas numbers: Energy balance
Interconnectors: thickness = utilisation of line
Interconnectors: colour = red (green) means high (little) price difference

Figure 41 Cost differences and cross-section utilization.

From Figure 41 it is shown how the average cost between areas in the Nordic differs. These cost differences are not the same as shown in the cost differences under each vision, as Figure 41 is based on different more detailed modelling of the energy system in the Nordic area. Water value calculations are there included ensuring a proper generation from the hydro in Norway, Sweden and Finland, and CHP modelling which is very important to get the Danish system balance correct. Furthermore Norway has been split into 7 subareas, Sweden into 4 and Finland into 2 areas in this modelling.

6. Potential future investments in the Nordic countries

The three main drivers for system evolution in the Nordic countries are market integration, integration of RES as well as conventional generation and security of supply. These drivers are followed by the refurbishment of aging equipment. In light of these drivers several internal projects in the Nordic countries as well as out of the region has been proposed. One of the biggest challenges in terms of the drivers is the uncertainty regarding the location and amount of generation in the future.

The projects and project candidates can be divided into two focus areas:

1. Internal investments in the Nordic countries
2. Investments in the cross section between the Nordic countries and Continental Europe

The projects and project candidates in this chapter are the ones presented in the RegIP2014/TYNDP2014. In addition to these projects, there are also a variety of projects that are included in each TSO's investment plan. Those investments are not presented here.

Seven different indicators have been calculated in the cost benefit calculated for each project analysed in the RegIP2014/TYNDP2014. The results of each indicator value are often given as a range which is presented in brackets in the tables as follows [From; To].

GTC direction in the tables is to be understood as *A=>B: 1000MW*. From area A to area B the capacity increase is 1000MW.

The presented indicators are described below:

B1 Security of Supply (SoS) – The ability of a power system to provide an adequate and secure supply of electricity in ordinary conditions in a specific area. Measured in MWh/year.

B2 Socio-economic welfare (SEW) – Characterised by the ability of a power system to reduce congestion and thus provide an adequate transmission capacity so that electricity markets can trade power in an economically efficient manner. Consists of Producer Surplus, Consumer Surplus and Congestion Rent. Measured in M€/year.

B3 Renewable Energy Sources (RES) integration – Defined as the ability of the power system to allow connection of new renewable power plants and unlock existing and future "green" generation, while minimising curtailment. Measured in MW or MWh depending on assessment method. For interconnectors between price areas and countries it is generally measured in MWh, while generation connection projects are measured in MW.

B4 Losses – Change in electrical losses is an indicator of energy efficiency for a power system. Hence the losses are calculated with and without an interconnector and subsequently subtracted from each other. Changes can be either positive or negative, where a positive number is to be read as the losses in the system increase while a negative number means that losses decrease. Measured in MWh/year.

B5 CO_2 Emissions – By relieving congestions reinforcements may enable low-carbon generation to generate more electricity, thus replacing conventional plants with higher carbon emissions. Changes can be either positive or negative, and a positive number should be read as the CO_2 emissions increase while a negative number means that the CO_2 emissions decrease. Measured in kT/year.

B6 Technical Resilience – This indicator shows the ability of the system to withstand increasingly extreme system conditions (exceptional contingencies). The indicator is the same for all studied Visions and are measured with Key Performance Indicators (KPI's). The scale is divided from 0 to 6 whereas 0 is the worst value and 6 is the best value.

B7 Robustness and Flexibility – The ability of the system to meet even those transmission needs that differ from present projections. The indicator is the same for all studied Visions and are measured with Key Performance Indicators (KPI's). The scale is divided from 0 to 6 whereas 0 is the worst value and 6 is the best value.

S1 and ***S2*** – In addition to the indicators explained above two more non scenario specific indicators are provided, giving a assessment of social and environmental impact. The indicators 'protected areas' (***S1***) and 'urbanised areas' (***S2***) are used to show:

- Where potential impacts have not yet been internalised, ie where additional expenditures may be necessary to avoid, mitigate and/or compensate for impacts but where these cannot yet be estimated with enough accuracy for the costs to be included in indicator C.1.
- The residual social and environmental effects of projects, ie effects which may not be fully mitigated in final project design and cannot be objectively monetised.

In order to provide a meaningful yet simple and quantifiable measure for these impacts, these indicators give an estimate of the length (number of kilometres) of a new line that might have to be located in an area that is sensitive due to its nature or biodiversity ('protected areas'), or that is densely populated ('urbanised areas').

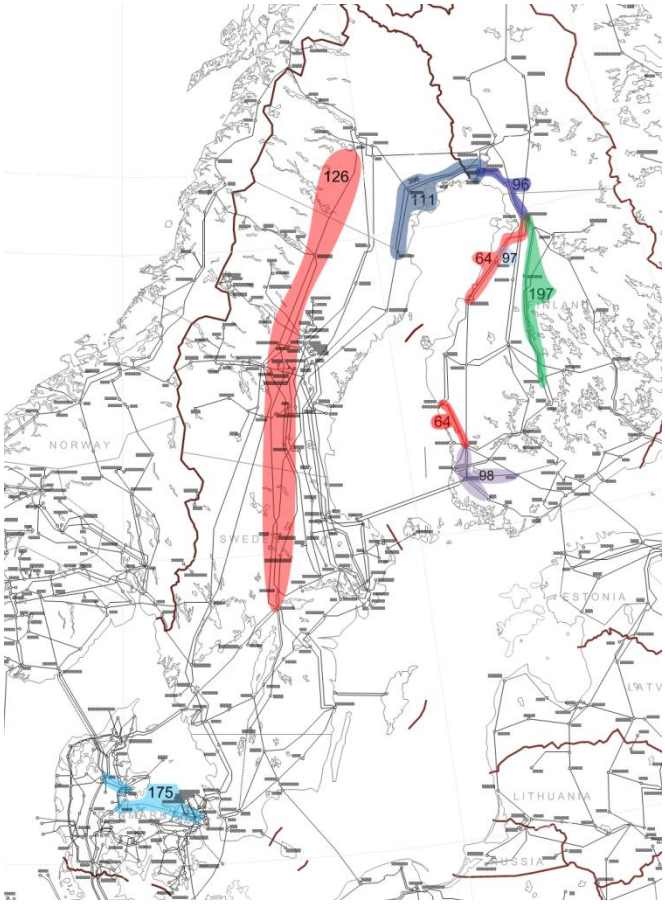
(S1) Protected areas	**(S2) Urban Areas**
0 km	0 km
15-25 km	15-25 km
25-50 km	25-50 km
50-100 km	Less than 15 km
Less than 15 km	More than 50 km
More than 50 km	
More than 100 km	

Table 3 The possible values of indicators (S1) and (S2) from the ENTSO-E CBA methodology.

C1 is the Estimated Cost in million Euros. The indicator is estimated on the basis of technology choice, routing of interconnection and capacity.

6.1 Focus area 1 – Internal interconnections in the Nordic Countries

This focus area includes reinforcement both within and between the Nordic countries.



ID	Project name	Increase (MW) market
64	North-South in Finland (P1) stage 1	700-1400
96	Keminmaa-Pyhänselkä	500-1000
97	97 FV connections	1250-1700
98	98 OL4 connection	1000-1800
111	Finland-Sweden	500/800
126	Northern to central Sweden	700-800
175	Great Belt II	600
197	North-South in Finland (P1) stage 2	1000

Figure 42 Internal interconnections in the Nordic Countries.

6.1.1 North-South in Finland (P1) stage 1 (64)

Several 400 kV AC lines are planned in Finland to be built to increase the north-south transmission capacity thus enabling the integration of new renewable and conventional generation in northern Finland and to compensate the dismantling of the obsolescent exiting 220 kV lines. The commissioning of the lines is scheduled to take place in segments both in mid and long term. Stage 1 includes the investments up until 2016.

The project has not been re-assessed for Visions up to 2030.

CBA results non scenario specific						
GTC direction 1 (MW)	**GTC direction 2 (MW)**	**B6 Technical Resilience**	**B7 Flexibility**	**S1 - protected areas**	**S2 - urban areas**	**C1 Estimated cost (M€)**
North-South: 700-1400	North-South: 700-1400	2	4	NA	NA	160-270

Table 4 Cost Benefit Analysis results for North-South Finland stage 1.

6.1.2 Northern part of Norway (68)

A 500 km long overhead line (Ofoten-Balsfjord-Skaidi-Hammerfest) in the northern part of Norway is planned to be realised in the years 2017 to 2021. The first step (Ofoten to Balsfjord) is planned to be realised by 2017, whereas the part from Balsfjord to Hammerfest is planned realised some years later. The line will improve security of supply and will be most important for petroleum industry in the northern part of Norway. Additionally, the line will be facilitating renewable energy (wind parks in the northern Norway). The line is planned to be a 420 kV overhead AC line.

The project has not been re-assessed for Visions up to 2030.

6.1.3 Integration Norway-Denmark, Skagerrak 4 (70)

A 240 km long interconnector (140 km subsea) between Norway and Denmark is planned to be in operation late 2014. The main driver for the project is to integrate the hydro-based Norwegian system with the thermal/wind/solar-based Danish/Continental system. The interconnector will improve security of supply both in Norway in dry years and in Germany in periods with negative power balance (low wind, low solar, high demand etc.). Additional the interconnector will be positive both for the European market integration, for facilitating renewable energy and also for preparing for a power system with lower CO_2 emission. The interconnector is planned to be a 500 kV 700 MW HVDC subsea interconnector between southern Norway and northern Denmark.

The project has not been re-assessed for Visions up to 2030.

6.1.4 RES/SoS Western and-Mid-Norway (93)

A 300 km long overhead line between Ørskog and Sogndal in the western part of Norway is planned to be realised in 2016. The line will improve security of supply and will be most important for industry consumption inclusive supply to important gas facilities. Additional the line will be facilitating renewable energy, six new transformer stations along the line will be crucial for the establishment of any new power production. The new line will as well be important for the market integration. Especially in dry years the price difference between mid-Norway and other price areas have been very high. The line is planned to be a 420 kV overhead AC line.

The project has not been re-assessed for Visions up to 2030.

6.1.5 New interconnection between Keminmaa and Pyhänselkä (96)

The project is a new 400 kV overhead line between Keminmaa and Pyhänselkä in Northern Finland. The new line that contributes to the integration of new generation at Bothnian bay and increased demand of capacity and will also help utilizing the Swedish/Finnish cross border capacity. The project is under consideration and is expected to be commissioned in 2024.

CBA results non scenario specific						
GTC direction 1 (MW)	**GTC direction 2 (MW)**	**B6 Technical Resilience**	**B7 Flexibility**	**S1 - protected areas**	**S2 - urban areas**	**C1 Estimated cost (M€)**
North=>South: 500-1000	South=>North: 500-1000	2	4	Negligible or less than 15km	Negligible or less than 15km	27-63

CBA results	**for each scenario**				
Scenario	**B1 SoS (MWh/year)**	**B2 SEW (M€/year)**	**B3 RES integration [MW]**	**B4 Losses (MWh/Year)**	**B5 CO_2 Emissions (kT/year)**
Scenario Vision 1 - 2030	0	[0;14]	1050	[-30000;-60000]	[0;240]
Scenario Vision 2 - 2030	0	0	[800;1200]	[-30000;-60000]	[0;500]
Scenario Vision 3 - 2030	0	[0;6]	1000	[-35000;-65000]	[0;-40]
Scenario Vision 4 - 2030	0	[0;68]	[1300;1800]	[-20000;-80000]	[0;-100]

Table 5 Cost benefit analysis results for the new interconection between Keminmaa and Pyhänselkä.

6.1.6 Fennovoima connection (97)

This project involves a new double circuit 400 kV OHL line between Valkeus (FIN) and Lumimetsä (FIN). The new line is required for connecting Fennovoimas new nuclear power plant being built in Pyhäjoki. The nuclear power plant has a planned generation capacity of 1250-1700 MW and the new line will have an equivalent capacity. The investor has stated that the plant will produce energy by 2024, expected commissioning of the lines by 2024.

CBA results non scenario specific						
GTC direction 1 (MW)	**GTC direction 2 (MW)**	**B6 Technical Resilience**	**B7 Flexibility**	**S1 - protected areas**	**S2 - urban areas**	**C1 Estimated cost (M€)**
FI=>FI: 1250-1700	FI=>FI: 1250-1700	4	2	Negligible or less than 15km	Negligible or less than 15km	25-60

CBA results	**for each scenario**				
Scenario	**B1 SoS (MWh/year)**	**B2 SEW (M€/year)**	**B3 RES integration**	**B4 Losses (MWh/year)**	**B5 CO_2 Emissions (kT/year)**
Scenario Vision 1 - 2030	0	[590;720]	0	0	0
Scenario Vision 4 - 2030	0	[440;540]	0	0	0

Table 6 Cost benefit analysis results for the new Fennovoima Connection.

6.1.7 Olkiluoto 4 Connection (98)

This project involves three new 400 kV over headlines Rauma (FIN) and Forssa (FIN), Lieto (FIN) respectively Ulvila (FIN) which are required for connecting TVO's new nuclear power plant that will be built in Olkiluoto, Finland. The nuclear power plant has a planned generation capacity of 1 000-1 800 MW and

the new line will have equivalent capacity. The investor has requested additional time for the decision in principle and estimates that the plant will produce energy by the latter part of 2020's. Expected commissioning of the lines according to the plans of the investor by the latter part of 2020's.

CBA results non scenario specific						
GTC direction 1 (MW)	**GTC direction 2 (MW)**	**B6 Technical Resilience**	**B7 Flexibility**	**S1 - protected areas**	**S2 - urban areas**	**C1 Estimated cost (M€)**
FI=>FI: 1000-1800	FI=>FI: 1000-1800	0	0	Negligible or less than 15km	Negligible or less than 15km	56-130

CBA results	**for each scenario**				
Scenario	**B1 SoS (MWh/year)**	**B2 SEW (M€/year)**	**B3 RES integration**	**B4 Losses (MWh/year)**	**B5 CO_2 Emissions (kT/year)**
Scenario Vision 4 - 2030	0	[440;540]	0	0	0

Table 7 Cost benefit analysis results for the new Olkiluoto 4 Connection.

6.1.8 RES Mid-Norway (104)

A 250 km coastal line (incl. 8 km subsea interconnector) is planned in the mid of Norway. Wind power projects with a total capacity of more than 1400 MW have received their final licenses. Statnett plans to prepare for wind farm development by constructing the necessary grid reinforcements once the wind power investments have been decided. Statnett's plan comprises a three-stage development of the new line.
Additional to the coastal line, voltage upgrade (300>420 kV) of existing lines in the area is planned. The first step will be the upgrade of the line Klæbu-Namsos. This will both be improving security of supply and facilitating renewable energy in the region.

The project has not been re-assessed for Visions up to 2030.

6.1.9 New interconnection between Northern Finland and Northern Sweden (111)

This project involves a third AC line (400 kV) on the cross border between Sweden North and Finland North. The reinforcement will strengthen the AC connection between Finland and Sweden which is needed due to new wind power generation, larger conventional units and decommissioning of the existing 220 kV interconnector between Kalix and Ossauskoski. The project is under consideration and is expected to be commissioned in 2025 after the new reinforcements of the Swedish north – south grid is completed.

CBA results non scenario specific						
GTC direction 1 (MW)	**GTC direction 2 (MW)**	**B6 Technical Resilience**	**B7 Flexibility**	**S1 - protected areas**	**S2 - urban areas**	**C1 Estimated cost (M€)**
FI=>SE: 500	SE=>FI: 800	6	6	Negligible or less than 15km	Negligible or less than 15km	56-130

CBA results	for each scenario				
Scenario	**B1 SoS (MWh/year)**	**B2 SEW (M€/year)**	**B3 RES integration (MWh/year)**	**B4 Losses (MWh/year)**	**B5 CO_2 Emissions (kT/year)**
Scenario Vision 1 - 2030	0	[1;2]	[4500;5500]	[106000;130000]	[230;280]
Scenario Vision 2 - 2030	0	[1;2]	[900;1100]	[210000;250000]	[440;530]
Scenario Vision 3 - 2030	0	[4;5]	[23000;28000]	[110000;130000]	[-48;-39]
Scenario Vision 4 - 2030	0	[54;66]	[250000;300000]	[170000;210000]	[-120;-96]

Table 8 Cost benefit analysis results for the new interconnection between Northern Finland and Northern Sweden.

6.1.10 New interconnection from Northern to Central Sweden (126)

A new connection from Northern Sweden to Central Sweden is under consideration. The reinforcement may contain both new stations and lines (AC and/or DC). The new connection is planned to increase the capacity from Northern Sweden (SE1) to Mid Sweden (SE2) and from Mid Sweden (SE2) to Central Sweden (SE3) with 800 MW respectively 700 MW. The new interconnection is expected to be commissioned in 2025.

There are several drivers for this project. By increasing the capacity from north to south, it will give a better possibility to carry out the necessary refurbishments of aging existing lines with acceptable market consequences. There is also an increased need of transmission capacity from north to south due to comprehensive plans for wind power in the Northern region. The reinforcement will also prepare for possible future interconnections to northern Norway/Finland as well as gives a greater opportunity to export to the continent, a need that is increased by a new possible interconnection to Germany.

CBA results non scenario specific						
GTC direction 1 (MW)	**GTC direction 2 (MW)**	**B6 Technical Resilience**	**B7 Flexibility**	**S1 - protected areas**	**S2 - urban areas**	**C1 Estimated cost (M€)**
North=>South: 700	South=>North: 700	2	4	NA	NA	660-1500

CBA results	for each scenario				
Scenario	**B1 SoS (MWh/year)**	**B2 SEW (M€/year)**	**B3 RES integration (MWh/Year)**	**B4 Losses (MWh/Year)***	**B5 CO_2 Emissions (kT/year)**
Scenario Vision 1 - 2030	0	[50;60]	[18000;22000]	[90000;110000]	[9;12]
Scenario Vision 2 - 2030	0	[57;69	[11000;13000]	[120000;150000]	[36;44]
Scenario Vision 3 - 2030	0	[57;69]	[30000;36000]	[90000;110000]	[18;22]
Scenario Vision 4 - 2030	0	[32;39]	[380000;460000]	[230000;280000]	[-52;-43]

*Losses in the Nordic grid plus losses on the HVDC itself.

Table 9 Cost benefit analysis results for a new interconnection from Northern to Central Sweden.

6.1.11 Great Belt II (175)

The project candidate has been analysed in the framework of the TYNDP2014, but presently there is no TSO-project investigating this connection in further detail. This project candidate includes a new 600 MW HVDC interconnector between Denmark West (DKW) and Denmark East (DKE). The interconnector is called Great Belt-2. It could among other variants be located between the 400 kV substation Malling in DKW and the reconstructed 400 kV substation Kyndby in DKE. The main purpose of this project would be to incorporate more RES into the Danish system, sharing reserves between both systems and improve market integration.

CBA results non scenario specific						
GTC direction 1 (MW)	**GTC direction 2 (MW)**	**B6 Technical Resilience**	**B7 Flexibility**	**S1 - protected areas**	**S2 - urban areas**	**C1 Estimated cost (M€)**
DKW=>DKE: 600	DKE=>DKW: 600	3	3	NA	NA	260-610

CBA results	for each scenario				
Scenario	**B1 SoS (MWh/year)**	**B2 SEW (M€/year)**	**B3 RES integration (MWh/Year)**	**B4 Losses (MWh/Year)**	**B5 CO_2 Emissions (kT/year)**
Scenario Vision 1 - 2030	0	0	0	[72000;87000]	[190;230]
Scenario Vision 2 - 2030	0	0	0	[72000;88000]	[65;80]
Scenario Vision 3 - 2030	0	[0;1]	[18000;22000]	[62000;76000]	[-50;-41]
Scenario Vision 4 - 2030	0	[2;3]	[45000;55000]	[62000;76000]	[-40;-33]

Table 10 Cost benefit analysis results for Great Belt II.

6.1.12 North-South in Finland (P1) stage 2 (197)

Several 400 kV AC lines are planned in Finland to be built to increase the north-south transmission capacity thus enabling the integration of new renewable and conventional generation in northern Finland and to compensate the dismantling of the obsolescent exiting 220 kV lines. The commissioning of the lines is scheduled to take place in segments both in medium and long term. Stage 2 is a project with 400 kV overhead lines for connecting North Finland to South. Expected commissioning 2023.

Project has not been re-assessed for visions 2030.

CBA results non scenario specific						
GTC direction 1 (MW)	**GTC direction 2 (MW)**	**B6 Technical Resilience**	**B7 Flexibility**	**S1 - protected areas**	**S2 - urban areas**	**C1 Estimated cost (M€)**
North-South: 1000	South-North 1000	2	4	NA	NA	55-130

Table 11 Cost benefit analysis results for North-South Finland stage 2.

6.1.13 Additional assessed projects in the Nordic Countries

In addition to the above mentioned projects, some additional potential project candidates has been evaluated in the RegIP2014 but not studied any further. The selection of the projects was done based on preliminary assessment results. More studies have to be performed in the future to find out the exact needs and possibilities of additional alternatives to the selected ones. The additional projects that were studied are given in Table 12 below.

Projects that are indexed by 1-3 in Table 12 and 4-6 in Table 26 are suggestions for an additional reinforcement out from The Nordic area that will be studied more in the future. These projects should be viewed as alternatives to each other.

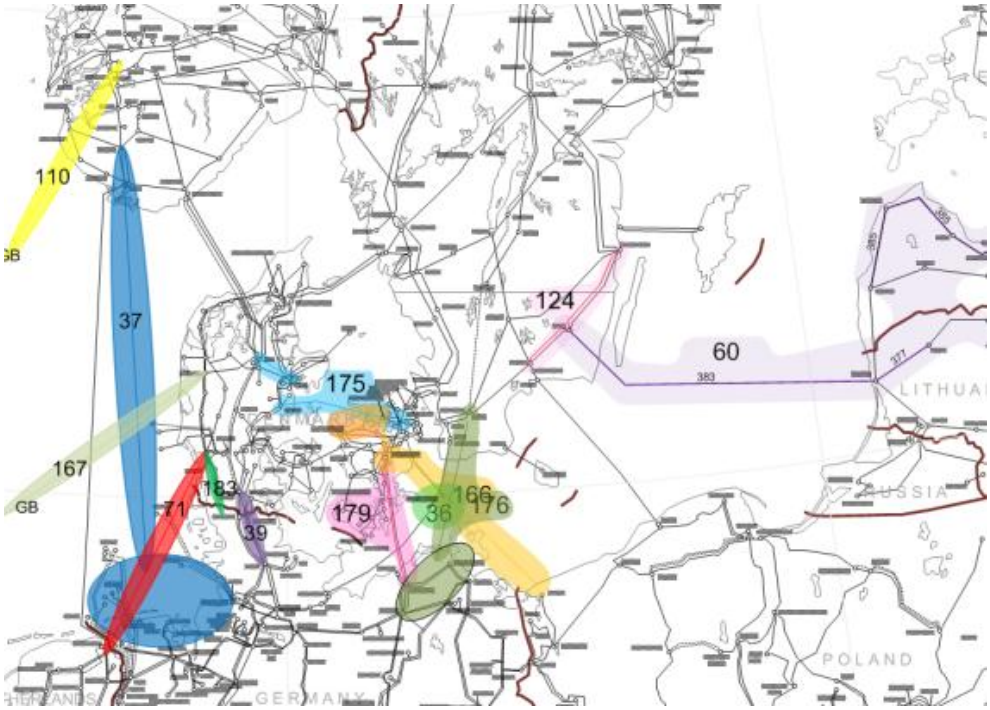
Project name	Increase MW (market)
Sweden Mid-Denmark West (SE3-DK1) [1]	700
Sweden South-Denmark East (SE4-DK2) [2]	700
Norway North - Sweden Mid (NNO-SE2) [3]	750
Finland North-Norway North	

Table 12 Additional evaluated project candidates in the Nordic Countries.

6.2 Focus Area 2 – Investments in the cross section between the Nordic Countries and Continental Europe/Baltic States

A majority of the projects in the cross section between the Nordic countries and Continental Europe are subsea HVDC cables connecting the synchronous areas via converter stations. The reason for a high interest in this particular cross section is the need to combine conventional power plants and wind power with

flexible and well balancing hydro power plants. There is also a tendency that the prices in the Nordic countries are lower than in Continental Europe causing bottlenecks between the areas. In TYNDP 2014/RegIP 2014 nine different projects were assessed. The assessed projects are presented in the map and table below.



Project Id	Project name	Increase MW (market)
36	Krieger's Flak CGS	400
37	Norway– Germany	1400
39	Denmark West-Germany	720/1000
60	NordBalt phase 1	700
71	COBRA Denmark West - Netherlands	700
110	Norway-Great Britain	1400
124	NordBalt phase 2	*
110	Norway-Great Britain	1400
166	Denmark East-Poland	600
167	Denmark West – Great Britain	1400
176	Hansa Power Bridge	600
179	Kontek 2	600
183	Denmark West – Germany, West Coast	1000/720
* This project is needed to accomplish full utilisation of the NordBalt phase 1 project		

Figure 43 Map and table representing projecs in the Cross section between the Nordic countries and Continental Europe/Baltic States (RGBS Regional investment plan).

6.2.1 Krieger's Flak CGS (36)

The Krieger's Flak Combined Grid Solution is a new DC offshore connection between Denmark and Germany. It will be used as a combined grid connection of the offshore wind farms Krieger's Flak in Denmark, Baltic 1 and 2 in Germany and a 400 MW interconnection between Ishøj/Bjæverskov in Denmark and Bentwisch/Güstrow in Germany. The project facilitates connection of RES and an increase in trade of electricity. The assessment refers only to the interconnection part of the project, not the windfarm connection, as it is assumed that this will be done in any case. Thus the cost reflect only the additional cost of the interconnection. The project is supported by the European Energy Programme for Recovery (EEPR) and labelled by the EC as a project of common interest (PCI). Kroger's Flak is now undergoing a design and permitting process and is expected to be commissioned in 2018.

CBA results non scenario specific						
GTC direction 1 (MW)	**GTC direction 2 (MW)**	**B6 Technical Resilience**	**B7 Flexibility**	**S1 - protected areas**	**S2 - urban areas**	**C1 Estimated cost (M€)**
DKE=>DE: 400	DE=>DKE: 400	3	3	Negligible or less than 15 km	Negligible or less than 15 km	230-380
CBA results	**for each scenario**					
Scenario	**B1 SoS (MWh/year)**	**B2 SEW (M€/year)**	**B3 RES integration (MWh/Year)**	**B4 Losses (MWh/Year)**	**B5 CO_2 Emissions (kT/year)**	
Scenario Vision 1 - 2030	0	[19;24]	[54000;66000]	[-62000;-51000]	[-130;-110]	
Scenario Vision 2 - 2030	0	[7;8]	[9000;11000]	[-62000;-50000]	[-4;-3]	
Scenario Vision 3 - 2030	0	[10;13]	[18000;22000]	[4500;5500]	[-390;-320]	
Scenario Vision 4 - 2030	0	[36;44]	[18000;22000]	[4500;5500]	[-760;-620]	

Table 13 Cost benefit analysis results for Krieger's Flak CGS.

6.2.2 Interconnection Norway and Germany, Nord Link (37)

A 514 km long subsea interconnector between Tonstad in Southern Norway and Wilster in Germany is planned to be realised in 2018. The main driver for the project is to integrate the hydro-based Norwegian system with the thermal/wind/solar-based Continental system. The interconnector will improve security of supply both in Norway in dry years and in Germany in periods with negative power balance (low wind, low solar, high demand etc.). Additional the interconnector will be positive both for the European market integration, for facilitating renewable energy and also for preparing for a power system with lower CO2-emission. The interconnector is planned to be a 500 kV 1400 MW HVDC subsea interconnector between southern Norway and northern Germany.

CBA results non scenario specific						
GTC direction 1 (MW)	**GTC direction 2 (MW)**	**B6 Technical Resilience**	**B7 Flexibility**	**S1 - protected areas**	**S2 - urban areas**	**C1 Estimated cost (M€)**
DE=>NO: 1400	NO=>DE: 1400	3	4	Negligible or less than 15 km	Negligible or less than 15 km	2100-3500

CBA results	for each scenario				
Scenario	**B1 SoS (MWh/year)**	**B2 SEW (M€/year)**	**B3 RES integration (MWh/Year)**	**B4 Losses (MWh/Year)**	**B5 CO_2 Emissions (kT/year)**
Scenario Vision 1 - 2030	0	[120;140]	[510000;620000]	[910000;1100000]	[-930;-760]
Scenario Vision 2 - 2030	0	[65;110]	[950000;1200000]	[910000;1100000]	[-670;-550]
Scenario Vision 3 - 2030	0	[210;280]	[1500000;1800000]	[910000;1100000]	[-2200;-1800]
Scenario Vision 4 - 2030	0	[350;400]	[1700000;2100000]	[910000;1100000]	[-3400;-2800]

Table 14 Cost benefit analysis results for a new interconnection between Southern Norway and Germany.

6.2.3 Denmark West – Germany (39)

This project is the third phase in the Danish-German agreement to upgrade the transfer capacity between Denmark West and Germany. The project consists of a new 124 km long 400 kV line from Kassoe (Denmark) to Audorf (Germany). It mainly follows the trace of an existing 220 kV line, which will be substituted by the new line. The project helps to integrate RES and to strengthen the connection between the Scandinavian and Continental market. The project is labelled by the EC as project of common interest (PCI). The project is expected to be commissioned in 2019.

CBA results non scenario specific						
GTC direction 1 (MW)	**GTC direction 2 (MW)**	**B6 Technical Resilience**	**B7 Flexibility**	**S1 residual environmental impact**	**S2 residual social impact**	**C1 Estimated cost (M€)**
DK1=>DE: 1000	DE=>DK1: 720	3	3	15-50 km	15-25 km	241

CBA results	for each scenario				
Scenario	**B1 SoS (MWh/year)**	**B2 SEW (M€/year)**	**B3 RES integration (MWh/Year)**	**B4 Losses (MWh/Year)**	**B5 CO_2 Emissions (kT/year)**
Scenario Vision 1 - 2030	0	20	60000	-42000	-105
Scenario Vision 2 - 2030	0	5	120000	35000	-35
Scenario Vision 3 - 2030	0	65	210000	56000	-620
Scenario Vision 4 - 2030	0	130	415000	56120	-1140

Table 15 Cost benefit analysis results for a new interconnection between Denmark West – Germany.

6.2.4 NordBalt Phase 1 (60)

The project includes both a 400 km 300 kV HVDC VSC cable between Klaipeda in Lithuania and Nybro in Sweden and internal investments in Lithuania, Latvia and Sweden. The HVDC interconnection will have a capacity of 700 MW and will be carried out with subsea and underground cable. The project will connect the Baltic and Nordic grid and play an important role in the integration of the Baltic countries with the Nordic electricity market as well as increase security of supply in the area. The project is supported by the European Energy Programme for Recovery (EEPR) and labelled by the EC as a project of common interest (PCI) The project is now under construction and expected to be commissioned in 2016.

CBA results non scenario specific						
GTC direction 1 (MW)	**GTC direction 2 (MW)**	**B6 Technical Resilience**	**B7 Flexibility**	**S1 - protected areas**	**S2 - urban areas**	**C1 Estimated cost (M€)**
LT=>SE: 700	SE=>LT: 700	4	4	Negligible or less than 15 km	Negligible or less than 15 km	690-1200

CBA results	for each scenario				
Scenario	**B1 SoS (MWh/year)**	**B2 SEW (M€/year)**	**B3 RES integration (MWh/Year)**	**B4 Losses (MWh/Year)**	**B5 CO_2 Emissions (kT/year)**
Scenario Vision 1 - 2030	0	[16;19]	[18000;22000]	[230000;280000]	[-90;-73]
Scenario Vision 2 - 2030	0	[35;42]	[18000;22000]	[320000;400000]	[1100;1300]
Scenario Vision 3 - 2030	0	[9;12]	[110000;130000]	[140000;170000]	[-650;-530]
Scenario Vision 4 - 2030	0	[180;220]	[110000;130000]	[350000;430000]	[-1400;-1200]

Table 16 Cost benefit analysis results for NordBalt Phase 1.

6.2.5 COBRA (71)

The project is an interconnection between Endrup in Demark and Eemshaven in the Netherlands. The purpose is to incorporate more renewable energy into both the Dutch and Danish power systems and to improve the security of supply. Moreover, the cable will help to intensify competition on the northwest European electricity markets. The project consists of a 320 kV 700 MW DC subsea cable and related substations in both ends, 320-350 km apart, applying VSC DC technology. The project is supported by the European Energy Programme for Recovery (EEPR) and is labelled by the EC as a project of common interest (PCI). The project is expected to be commissioned in 2019.

CBA results non scenario specific						
GTC direction 1 (MW)	**GTC direction 2 (MW)**	**B6 Technical Resilience**	**B7 Flexibility**	**S1 - protected areas**	**S2 - urban areas**	**C1 Estimated cost (M€)**
DKW=>NL: 700	NL=>DKW: 700	3	3	Negligible or less than 15 km	Negligible or less than 15 km	370-870

CBA results	for each scenario				
Scenario	**B1 SoS (MWh/year)**	**B2 SEW (M€/year)**	**B3 RES integration (MWh/Year)**	**B4 Losses (MWh/Year)**	**B5 CO_2 Emissions (kT/year)**
Scenario Vision 1 - 2030	0	[5;25]	[45000;55000]	[44000;54000]	[-120;-94]
Scenario Vision 2 - 2030	0	[0;10]	[27000;33000]	[44000;54000]	[-44;-36]
Scenario Vision 3 - 2030	0	[25;85]	[180000;220000]	[110000;130000]	[-560;-460]
Scenario Vision 4 - 2030	0	[100;150]	[350000;420000]	[110000;130000]	[-920;-760]

Table 17 Cost benefit analysis results for COBRA (Denmark West – Holland).

6.2.6 Interconnection Norway and Great Britain, NSN-North Sea Network (110)

A 720 km long subsea interconnector between Kvilldal in western Norway and Blythe in England is planned to be realised in 2020. If realised it will be the world's longest. The main driver for the project is to integrate the hydro-based Norwegian system with the thermal/nuclear/wind-based British system. The interconnector will improve security of supply both in Norway in dry years and in Great Britain in periods with negative power balance (low wind, low solar, high demand etc.). Additional the interconnector will be positive both for the European market integration, for facilitating renewable energy and also for preparing for a power system with lower CO_2-emission. The interconnector is planned to be a 500 kV 1400 MW HVDC subsea interconnector between western Norway and eastern England.

Both the NSN and the NorthConnect-project are showing very high values regarding RES-integration. The reason for this is that the projects lead to both decreased spillage in Great Britain (when windy) and in the Nordic countries (when wet).

CBA results non scenario specific						
GTC direction 1 (MW)	**GTC direction 2 (MW)**	**B6 Technical Resilience**	**B7 Flexibility**	**S1 - protected areas**	**S2 - urban areas**	**C1 Estimated cost (M€)**
GB=>NO: 1400	NO=>GB: 1400	2	4	Negligible or less than 15 km	Negligible or less than 15 km	1300-3000

CBA results	**for each scenario**				
Scenario	**B1 SoS (MWh/year)**	**B2 SEW (M€/year)**	**B3 RES integration (MWh/Year)**	**B4 Losses (MWh/Year)**	**B5 CO_2 Emissions (kT/year)**
Scenario Vision 1 - 2030	0	[150;220]	[1000000;1200000]	[760000;930000]	[-440;-360]
Scenario Vision 2 - 2030	0	[90;170]	[900000;1100000]	[760000;930000]	[-240;-190]
Scenario Vision 3 - 2030	0	[280;360]	[2700000;3300000]	[760000;930000]	[-2000;-1700]
Scenario Vision 4 - 2030	0	[280;300]	[2100000;2600000]	[760000;930000]	[-1800;-1500]

Table 18 Cost benefit analysis results for a new interconnection between Norway and Great Britain.

6.2.7 NordBalt Phase 2 (124)

This project contains internal investment in Lithuania and Sweden that are needed to accomplish full utilisation of the NordBalt cable between Sweden and Lithuania (NordBalt phase1, see chapter 6.2.3). The needed investment in Sweden is a new single circuit 400 kV OHL from Ekhyddan to Nybro and then to Hemsjö. The project is under planning and expected to be in commission 2023. The NordBalt project has been divided into two phases to fulfil the CBA criteria. In the RegIP 2014 analysis, the total increase in capacity was referred to phase 1. Therefor B2, B3 and B5 are only calculated for phase 1 but should be interpreted as the values for phase 1 and 2 together. The indicators B4, B6 and B7 have been calculated for both phases individually.

CBA results non scenario specific						
GTC direction 1 (MW)	**GTC direction 2 (MW)**	**B6 Technical Resilience**	**B7 Flexibility**	**S1 - protected areas**	**S2 - urban areas**	**C1 Estimated cost (M€)**
LT=>SE: 700	SE=>LT: 700	4	3	NA	NA	130-310
CBA results	**for each scenario**					
Scenario	**B1 SoS (MWh/year)**	**B2 SEW (M€/year)**	**B3 RES integration**	**B4 Losses (MWh/Year)***	**B5 CO_2 Emissions (kT/year)**	
Scenario Vision 1 - 2030	0	0	0	[-110000;-88000]	0	
Scenario Vision 2 - 2030	0	0	0	[105000;-86000]	0	
Scenario Vision 3 - 2030	0	0	0	[-108000;-88000]	0	
Scenario Vision 4 - 2030	0	0	0	[-77000;-63000]	0	
*Only difference in losses in the internal Nordic grid.						

Table 19 Cost benefit analysis results for NordBalt phase 2.

6.2.8 New interconnection between Eastern Denmark and Poland (166)

The project has been analysed in the framework of the TYNDP2014, but presently there is no TSO-project investigating this connection in further detail. This project candidate is a new interconnector between Bjaeverskov in Denmark and Dunowo in Poland. The connections could be a 500 kV 600 MW HVDC subsea connection to connect the different market areas.

CBA results non scenario specific						
GTC direction 1 (MW)	**GTC direction 2 (MW)**	**B6 Technical Resilience**	**B7 Flexibility**	**S1 - protected areas**	**S2 - urban areas**	**C1 Estimated cost (M€)**
600	600	3	3	NA	NA	760
CBA results	**for each scenario**					
Scenario	**B1 SoS (MWh/year)**	**B2 SEW (M€/year)**	**B3 RES integration (MWh/Year)**	**B4 Losses (MWh/Year)**	**B5 CO_2 Emissions (kT/year)**	
Scenario Vision 1 - 2030	0	[20;25]	[27000;33000]	[183000;224000]	[1400;1700]	
Scenario Vision 2 - 2030	0	[35;45]	[27000;33000]	[-223000;-183000]	[1400;1700]	
Scenario Vision 3 - 2030	0	[50;60]	0	[166000;203000]	[-2400;-3000]	
Scenario Vision 4 - 2030	0	[130;160]	[126000;154000]	[166000;203000]	[-2000;-2400]	

Table 20 Cost benefit analysis results for a new interconnection between Eastern Denmark and Poland.

6.2.9 Denmark West – Great Britain (167)

This project candidate is investigated and assessed in the TYNDP as a connection between Idomlund (Denmark West) and Great Britain by two parallel 700 MW HVDC subsea cables and related substations on both ends. A final route is not designed yet - the investigated project is one out of several possible alternatives. The project cluster includes in Denmark additionally the establishment of a 400 kV AC underground cable system between the 400 kV substation Idomlund and the existing 400 kV substation Endrup with needed compensation arrangements. The parts of national investments already known from TYNDP12 are included in this project cluster. The project adds cross-border transmission capacity between both countries, thereby facilitating the incorporation of more RES, as the wind is not correlated between both markets.

CBA results non scenario specific						
GTC direction 1 (MW)	**GTC direction 2 (MW)**	**B6 Technical Resilience**	**B7 Flexibility**	**S1 - protected areas**	**S2 - urban areas**	**C1 Estimated cost (M€)**
DKW=>GB: 1400	GB=>DKW: 1400	2	4	NA	NA	1700-4000

CBA results	**for each scenario**				
Scenario	**B1 SoS (MWh/year)**	**B2 SEW (M€/year)**	**B3 RES integration (MWh/Year)**	**B4 Losses (MWh/Year)***	**B5 CO_2 Emissions (kT/year)**
Scenario Vision 1 - 2030	0	[75;110]	[320000;400000]	[200000;250000]	[570;690]
Scenario Vision 2 - 2030	0	[25;45]	[77000;94000]	[240000;290000]	[380;460]
Scenario Vision 3 - 2030	0	[220;300]	[2300000;2900000]	[360000;440000]	[-2000;-1600]
Scenario Vision 4 - 2030	0	[240;270]	[1800000;2200000]	[350000;420000]	[-1800;-1400]

*Nordic losses and losses on the cable itself.

Table 21 Cost benefit analysis results for Denmark West – Great Britain.

6.2.10 Hansa Power Bridge (176)

The project is a new interconnection between Sweden south (SE4) and Germany (50Hertz). An estimated increase in future production in the Nordic countries also increases the need for sufficient capacity to our neighbouring countries. This will help to increase the export of carbon-free production and replace fossil power generation on the continent. The need for a stronger connection to the continent is also stressed because of the German nuclear decommissioning, which is supposed to be implemented by 2022. There is also an increased need for handling the expected large variation in power production caused by the large amounts of RES introduced in Europe. Production surplus in Continental Europe on windy, sunny days need to be efficiently used and the energy can be "stored" in the Nordic hydro power reservoirs. The new interconnection is now under consideration and has an estimated capacity of 600-700 MW and will be realised as a HVDC-link. Expected year of commission is before 2025.

CBA results non scenario specific						
GTC direction 1 (MW)	**GTC direction 2 (MW)**	**B6 Technical Resilience**	**B7 Flexibility**	**S1 - protected areas**	**S2 - urban areas**	**C1 Estimated cost (M€)**
DE=>SE: 600	SE=>DE: 600	3	3	NA	NA	180-420

CBA results	for each scenario				
Scenario	**B1 SoS (MWh/year)**	**B2 SEW (M€/year)**	**B3 RES integration (MWh/Year)**	**B4 Losses (MWh/Year)***	**B5 CO_2 Emissions (kT/year)**
Scenario Vision 1 - 2030	0	[72;88]	[36000;44000]	[300000;360000]	[590;720]
Scenario Vision 2 - 2030	0	[15;18]	[36000;44000]	[190000;230000]	[340;420]
Scenario Vision 3 - 2030	0	[28;35]	[90000;110000]	[250000;300000]	[-710;-580]
Scenario Vision 4 - 2030	0	[220;270]	[90000;110000]	[280000;350000]	[-2200;-1800]
*Nordic losses and losses on the cable itself.					

Table 22 Cost benefit analysis results for Hansa Power Bridge.

6.2.11 New interconnection between Denmark East and Germany (Kontek 2) (179)

The project candidate has been analysed in the framework of the TYNDP2014, but presently there is no TSO-project investigating this connection in further detail. This project candidate includes a 600 MW HVDC subsea interconnector between Denmark East and Germany and is called Kontek 2. As a final grid connection solution is not prepared yet; one possible alternative could be to establish a HVDC converter station in the area of Lolland-Falster. The HVDC converter station could be connected to the existing 400 kV substation Bjaerverskov via 400 kV underground cables and/or 400 kV OHL. Some additional investments in Denmark East would be necessary, which are not described in this document.

CBA results non scenario specific						
GTC direction 1 (MW)	**GTC direction 2 (MW)**	**B6 Technical Resilience**	**B7 Flexibility**	**S1 - protected areas**	**S2 - urban areas**	**C1 Estimated cost (M€)**
DKE=>DE: 600	DE=>DKE: 600	3	3	NA	NA	330-770
CBA results	**for each scenario**					
Scenario	**B1 SoS (MWh/year)**	**B2 SEW (M€/year)**	**B3 RES integration (MWh/Year)**	**B4 Losses (MWh/Year)**	**B5 CO_2 Emissions (kT/year)**	
Scenario Vision 1 - 2030	0	[31;38]	[54000;66000]	[17000;21000]	[82;100]	
Scenario Vision 2 - 2030	0	[22;27]	[54000;66000]	[-2200;-1800]	[73;90]	
Scenario Vision 3 - 2030	0	[22;27]	[63000;77000]	[120000;150000]	[-890;-720]	
Scenario Vision 4 - 2030	0	[140;170]	[63000;77000]	[120000;150000]	[-1900;-1600]	

Table 23 Cost benefit analysis results for a new interconnection between Denmark East and Germany (Kontek 2).

6.2.12 New interconnection between Denmark West and Germany, West Coast (183)

The project candidate consists of a new 400 kV line from Endrup (Denmark) to Niebüll (Germany), adding another 500 MW at the West Coast between these countries. On the Danish side, this could be established as a 400 kV AC underground cable system from the existing 400 kV substation Endrup, via Ribe and Bredebro to the border, from where the interconnector could continue to Niebüll. The project helps to integrate RES and to strengthen the connection between the Scandinavian and Continental market. The project is labelled by the EC as project of common interest (PCI) and could be commissioned in 2021/2022.

CBA results non scenario specific						
GTC direction 1 (MW)	**GTC direction 2 (MW)**	**B6 Technical Resilience**	**B7 Flexibility**	**S1 - protected areas**	**S2 - urban areas**	**C1 Estimated cost (M€)**
DKW=>DE: 500	DE=>DKW: 500	2	3	Negligible or less than 15km	Negligible or less than 15km	110-270
CBA results	**for each scenario**					
Scenario	**B1 SoS (MWh/year)**	**B2 SEW (M€/year)**	**B3 RES integration [MWh]**	**B4 Losses (MWh/Year)**	**B5 CO_2 Emissions (kT/year)**	
Scenario Vision 1 - 2030	0	[0;10]	[14000;17000]	[-11000;-9000]	[-88;-72]	
Scenario Vision 2 - 2030	0	[4;5]	[14000;17000]	[-11000;-9000]	[-22;-18]	
Scenario Vision 3 - 2030	0	[20;60]	[120000;140000]	[-12000;-9900]	[-440;-360]	
Scenario Vision 4 - 2030	0	[80;100]	[260000;310000]	[-12000;-9600]	[-830;-680]	

Table 24 Cost benefit analysis results for a new interconnector between Denmark west and Germany

6.2.13 Interconnection Norway and Great Britain, NorthConnect (190)

A 650 km long subsea interconnector between Norway and Scotland is planned to be realised in 2021. The main driver for the project is to integrate the hydro-based Norwegian system with the thermal/nuclear/wind-based British system. The interconnector will improve security of supply both in Norway in dry years and in Great Britain in periods with negative power balance (low wind, low solar, high demand etc.). Additional the interconnector will be positive both for the European market integration, for facilitating renewable energy and also for preparing for a power system with lower CO2-emission. The interconnector is planned to be a 500 kV 1400 MW HVDC subsea interconnector between western Norway and eastern Scotland.

The results for NorthConnect (Norway-Scotland) is the same as for project 110 NSN (Norway-England), this because Great Britain in the analysis is modelled as one node. In practice there would have been price-differences between England and Scotland, making the values different for the two projects. Additional NorthConnect is planned realised after NSN, which will make this project NorthConnect less valuable. The Norwegian grid of today is only dimensioned for one interconnector Norway-Great Britain.

Both the NSN and the NorthConnect are showing very high values regarding RES-integration. The reason for this is that the project leads to both decreased spillage in Great Britain (when windy) and in the Nordic countries (when wet).

CBA results non scenario specific						
GTC direction 1 (MW)	**GTC direction 2 (MW)**	**B6 Technical Resilience**	**B7 Flexibility**	**S1 - protected areas**	**S2 - urban areas**	**C1 Estimated cost (M€)**
GB=>NO: 1400	NO=>GB: 1400	4	4	Negligible or less than 15km	Negligible or less than 15km	1300-3000
CBA results		**for each scenario**				
Scenario		**B1 SoS (MWh/year)**	**B2 SEW (M€/year)**	**B3 RES integration (MWh/Year)**	**B4 Losses (MWh/Year)**	**B5 CO_2 Emissions (kT/year)**
Scenario Vision 1 - 2030		0	[150;220]	[1000000;1200000]	[760000;930000]	[-440;-360]
Scenario Vision 2 - 2030		0	[90;170]	[900000;1100000]	[760000;930000]	[-240;-190]
Scenario Vision 3 - 2030		0	[280;360]	[2700000;3300000]	[760000;930000]	[-2000;-1700]
Scenario Vision 4 - 2030		0	[280;300]	[2100000;2600000]	[760000;930000]	[-1800;-1500]

Table 25 Cost benefit analysis results for a new interconnection between Norway and Great Britain.

6.2.14 Additional assessed project candidates in the cross section between the Nordic Countries and Continental Europe/Baltic States

In addition to the above mentioned projects, some additional potential project candidates has been evaluated in the RegIP2014 but not studied any further. The selection of the projects was carried out based on preliminary assessment results. More studies have to be performed in the future to find out the exact needs and possibilities of additional alternatives to the selected ones. The additional projects that were studied are given in the Table 26 below.
Projects that are indexed by 4-6 in Table 26 and 1-3 in Table 12 are suggestions for an additional reinforcement out from the Nordic area that will be studied more in the future. Those projects should be viewed as alternatives to each other.

Project name	Increase MW (market)
SE4-PL [4]	600
SE4-DE [5]	600
SE3-LAT [6]	700
DK2-DE	600
The DK2-DE connection is 600MW additional to the Kontek2 link.	

Table 26 Additional evaluated project candidates in the cross section between the Nordic Countries and Continental Europe/Baltic States.

7. North Sea offshore grid

In December 2010 the energy related Ministries of the ten countries around the Northern Seas signed a Memorandum of Understanding, forming the North Seas Countries' Offshore Grid Initiative (NSCOGI). The countries involved are the Regional Group North Sea countries plus Sweden – thus, a close cooperation between the ENTSO-E Regional group North Sea and the NSCOGI is quite natural.

Within this framework, the region's key stakeholders (Ministries, TSOs and National Regulators, together with the European Commission) are gathered to achieve a common regional basis for offshore infrastructure development. The initiative is based on the insight that without cooperation, both internationally and between the very different actors, the offshore grid issue cannot be resolved.

The NSCOGI is divided into three work streams: one focusing on grid development, the second on market and regulatory arrangements and the third on permit and authorization issues. RGNS cooperation mostly focuses on grid development issues, but is also involved in the other streams and the Programme Board as well.

During the first two years, the RGNS especially served the grid development work stream, where a comprehensive Offshore-Grid study was executed, analysing two contrasting designs, radial versus meshed

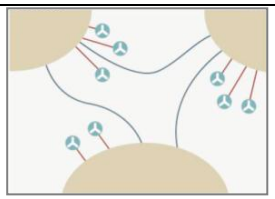
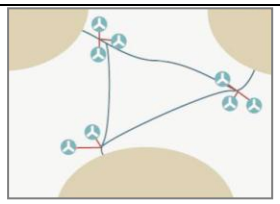
	
Radial – implying continuation with primarily uni- and bilateral solutions	**Offshore Grid** – implying close international cooperation between North Seas' countries.

Figure 44 General design concepts.

In this study, investment costs, savings in electricity production costs, effects on CO_2 emissions and countrywide changes for electricity imports and exports have been evaluated and compared. The whole study can be downloaded from the internet (http://www.benelux.int/NSCOGI/), but the main results are presented here in short.

7.1.1 Offshore grid study – Main assumptions and results

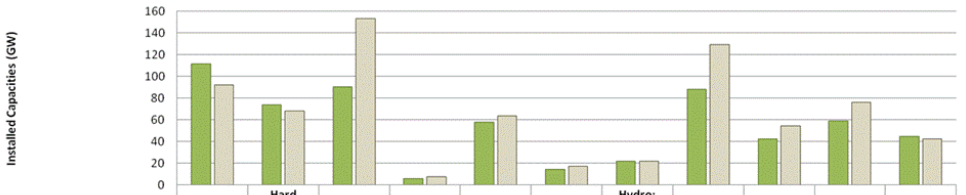
Scenario development

The study provided a view on how a meshed offshore grid could develop over the period 2020 to 2030 as the countries in the North Seas region advance towards a low carbon energy future. It was based on the 10 single governments' best view of the 2030 situation concerning energy generation and demand as expressed in summer 2011.

These data, called "Reference Scenario" were then combined with IEA scenario fuel and CO_2 prices (World Energy Outlook 2010, new policies scenario). Correlated wind time series and solar time series were scaled up to year 2030 values. The generation data was grouped into power plant types with start-up times and other technical operating parameters added.

With regard the grid analysis, the study that the 2020 was developed in accordance with TYNDP 2012, including all new interconnectors identified in the TYNDP 2012. - Which implies some of 77 Bn € of regional investments until 2020 already been undertake. The required developments from 2020 to 2030 where then considered.

The evolution of the system in terms of installed generating capacities between the year 2020 and 2030 is shown in Figure 3. The year 2020 was based on scenario EU2020 from the TYNDP 2012. In this scenario the 2020 targets are met, and is based on the National Renewable Energy Action Plans (NREAPs) of the European Member states.



	Nuclear	Hard coal/lignite fired	Gas fired	Oil fired	Hydro: Reservoir	Hydro: Run of river	Hydro: Pumped storage	Onshore wind	Offshore wind	Solar	Other
EU2020	111	74	90	6	58	14	22	88	42	59	45
NSCOGI Reference Scenario	92	68	153	7	64	17	21	129	55	76	43
Change [GW]	- 19	- 6	+ 63	+ 1	+ 6	+3	- 1	+ 41	+ 13	+ 17	- 2
Change [%]	- 17	- 8	+ 70	+ 17	+ 10	+21	- 5	+ 47	+ 31	+ 29	- 4

Figure 45 Comparison of installed capacities (in GW) in the NSCOGI perimeter in the years 2020 and 2030.

The electricity production capacity in the region is assumed to increase in total by 19%: Installed nuclear capacities reduce by 17% while installed hard coal and lignite-fired capacities decrease by 8%. In contrast, there is a 70% increase in gas-fired capacity from 90 GW in 2020 to 153 GW in 2030.

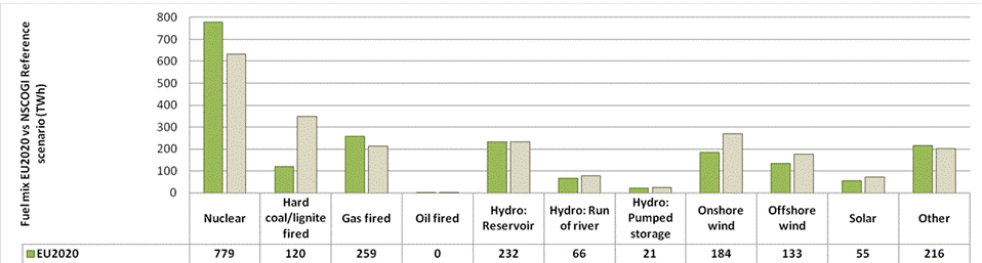
Overall there is a net 14% increase in the installed thermal generating capacities, while variable RES (wind, solar and hydro) is expected to increase by 29% or 79 GW. Of the RES production the most significant increase is delivered from wind generation. However, most of this increase is assumed to occur onshore (+ 41GW) with just a 13 GW increase offshore, bringing the offshore capacity from 42 GW in 2020 to 55 GW in 2030.

The demand during the period 2020 – 2030 increases by 9% from 1,922 TWh to 2,101 TWh. If the demand and supply side developments defined in the scenario are compared it becomes clear that there is greater excess capacity in the 2030 Reference Scenario than in 2020. As a result, the average utilisation of the installed thermal capacities will decrease significantly unless thermal generation is used to meet additional demand outside the region.

Energy produced by different fuel types

Market studies where undertaken to assess the energy produced by each fuel type, results as shown in Figure 11-3 below. Although installed gas capacity was assumed to increase by 70%, and coal capacity decreases by 8%, the energy production behaves inversely with an 18% decrease for gas, but 190% increase for coal due to the impact of the assumed merit order. This generation utilisation plays a major role in the countries' import / export and related infrastructure requirements to facilitate these transfers.

In an energy only market and under this scenario the output from this study would suggest that is doubtful whether gas-fired plant would have sufficient utilisation hours to be profitable with the assumed CO_2 price and fuel prices of gas and coal. The resulting infrastructure for the Reference scenario will need to be re-evaluated if the underlying production mix assumptions are changed. For every study, the input data and output are closely related.



	Nuclear	Hard coal/lignite fired	Gas fired	Oil fired	Hydro: Reservoir	Hydro: Run of river	Hydro: Pumped storage	Onshore wind	Offshore wind	Solar	Other
EU2020	779	120	259	0	232	66	21	184	133	55	216
NSCOGI Reference Scenario	633	348	212	1	234	77	23	270	176	71	202
Change [TWh]	- 146	+ 228	- 47	+ 1	+ 2	+ 11	+ 2	+ 86	+ 43	+ 16	- 14
Change [%]	- 19	+ 190	- 18		+ 0,9	+ 17	+ 10	+ 47	+ 32	+ 29	- 7

Figure 46 Comparison of fuel mix in energy consumption (TWh) in the NSCOGI countries 2020 (green) versus 2030 (grey).

The utilisation of this volume of coal also had a direct impact on CO_2 emissions, the results of this study indicated the CO_2 emissions stayed constant between 2020 and 2030 for the region, although some movements could be observed with respect to individual countries with respect to where the emissions were produced.

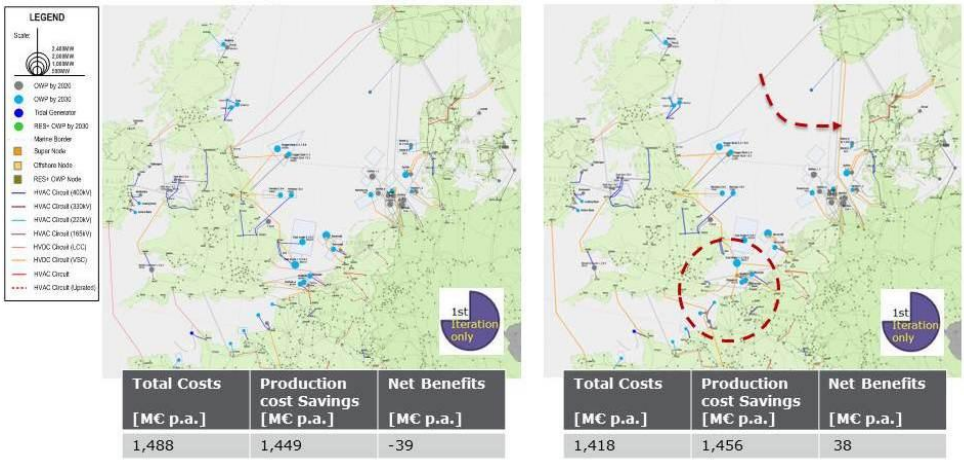
Resulting grid designs

The designs presented in the study have been developed using an optimization minimizing the regional cost for electricity production. Designs are shown to illustrate possible evolution of the electricity transmission system designs. The designs neither represent a construction program or an investment decision of the involved Governments, TSOs or offshore generator developers. Actual development of the transmission systems in each of the North Seas countries may differ significantly to those presented, due to necessary assumptions adopted around perfect functioning markets, absence of regulatory barriers and common assumptions on fuel / CO_2 prices utilised in this investigations – as is the case for any of these type of analysis. The output is provides a Vision and direction of possible future networks and will require further in-depth analysis with range of appropriate sensitivity studies to determine optimum network solution.

Both, the radial and meshed approach result in a similar levels of interconnection, with similar associated production cost savings, although there are significant differences in how they were achieved, e.g. the routing of some major flows across the region shifted between both designs, resulting in different levels of investment for the countries. The results summed up to roughly 9,000 km of new lines to be built at the cost in the order of 30bn€.

Also market benefits, import/export positions and CO_2 emissions were r similar. The similarity in results can be explained by the relatively small volume of offshore renewable energy assumed to be installed between 2020 and 2030 in this scenario.

There might be other implications of both designs, including challenges and possible advantages of a meshed design, which are less quantifiable, such as operational flexibility and fewer landing points on the one hand and some technical challenges on the other hand. Neither of these has been investigated within the scope of this study.



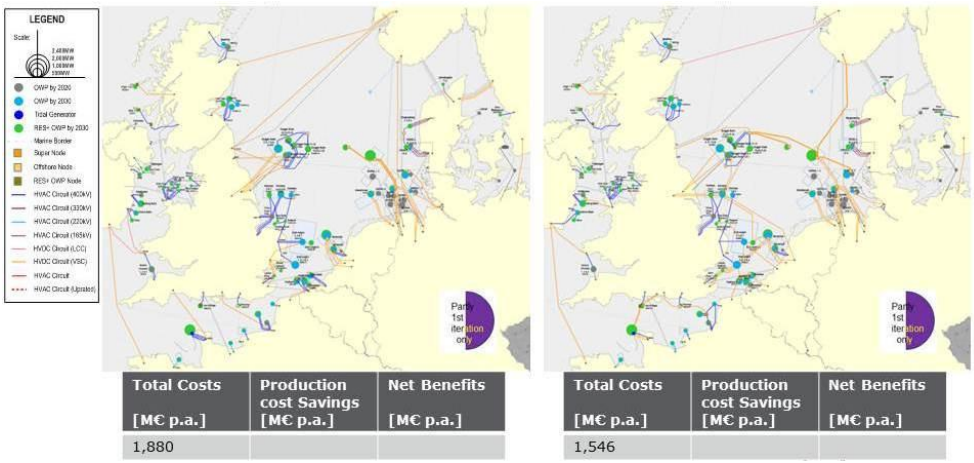
A) ReferenceScenario 2030,
radial solution,
55 GW offshore wind
(source: NSCOGI)

B) Reference Scenario 2030,
meshed solution,
55 GW offshore wind
(source: NSCOGI)

Figure 47 Resulting Grid Designs: A) Radial; B) Meshed.

Additionally, a sensitivity study was undertaken with about twice as much offshore wind (117 GW), which demonstrated increased benefits for a meshed transmission network solution.

The sensitivity analysis did not investigate everything in detail, as the time available for the investigations was very short and there was only room for an initial estimation. The implications on the onshore grid development had not been investigated, as indicated in the maps.



A) RES+ Sensitivity 2030,
radial solution,
117 GW offshore wind
(source: NSCOGI)

B) RES+-Sensitivity 2030,
meshed solution,
117 GW offshore wind
(source: NSCOGI)

Figure 48 Resulting Grid designs "RES +" Sensitivity: A) Radial; B) Meshed.

These high volumes of offshore wind capacity are not expected before 2020, and there remains significant uncertain on potential volumes for 2030, particularly given that renewable targets for 2030 have not yet been defined.

The study also concluded in December 2012 that since a potential offshore grid would be built in a modular way with every step influencing existing and future projects, it is highly complex if not impossible to identify a final efficient design. I. Moreover, even if an offshore grid might be preferable as a general concept, it may not offer the best solution for all offshore generation or interconnection projects, depending on their location and on possible connection options. For some offshore projects (both, wind or interconnections) the meshed solution could present a possible option, which should be evaluated on a case-by-case basis using the study assumptions relevant for the respective project.

7.1.2 Comparison NSCOGI Scenarios to ENTSO-E visions

A short comparison of the sensitivity analysis, called "RES+" scenario with the TYNDP Visions has been made. The demand of both NSCOGI scenarios lies between Vision 1, Vision 2 and Vision 3, Vision 4, but this can look differently for each single country.

With respect to the installed capacities and fuel types, there is a difference in nuclear, coal and gas in the NSCOGI scenarios, where these are higher compared to the ENTSO-E Visions.

In Visions 3 and 4, ENTSO-E proposes more solar compared to NSCOGI, Vision 4 more wind than NSCOGI RES+, which is nearly at the level of Vision 3.

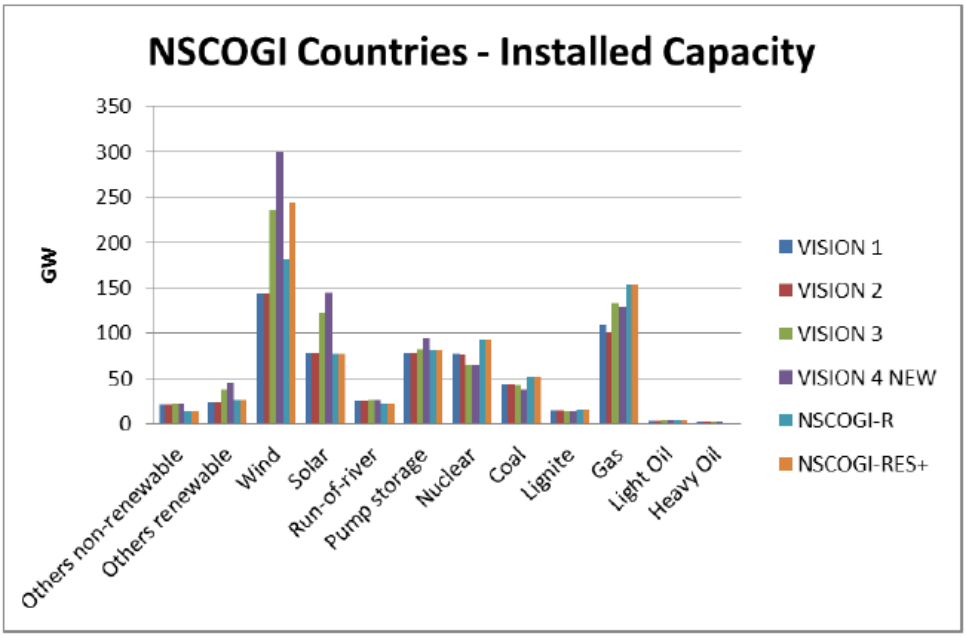


Figure 49 Comparison of scenarios: Installed capacity in NSCOGI countries 2030.

It can be concluded that the NSCOGI RES+ scenario lies within the envelope of the 4 ENTSO-E Visions, thus it is one version of the possible futures. The only exception can be seen for thermal units – the national governments' expectations of the future were higher compared to the ENTSO-E Visions. ENTSO-E visions' thereby take the low amount of running hours for thermal units into account which will result in smaller amount of thermal units in the European energy system.

It has to be kept in mind that the collection of national views was made in summer 2011 – afterwards some governments adapted their view, e.g. in France the nuclear power is expected to decrease, in Germany and Great Britain the gas fired plants are expected to be reduced whereas in the Netherlands less coal fired plants are expected to be online.

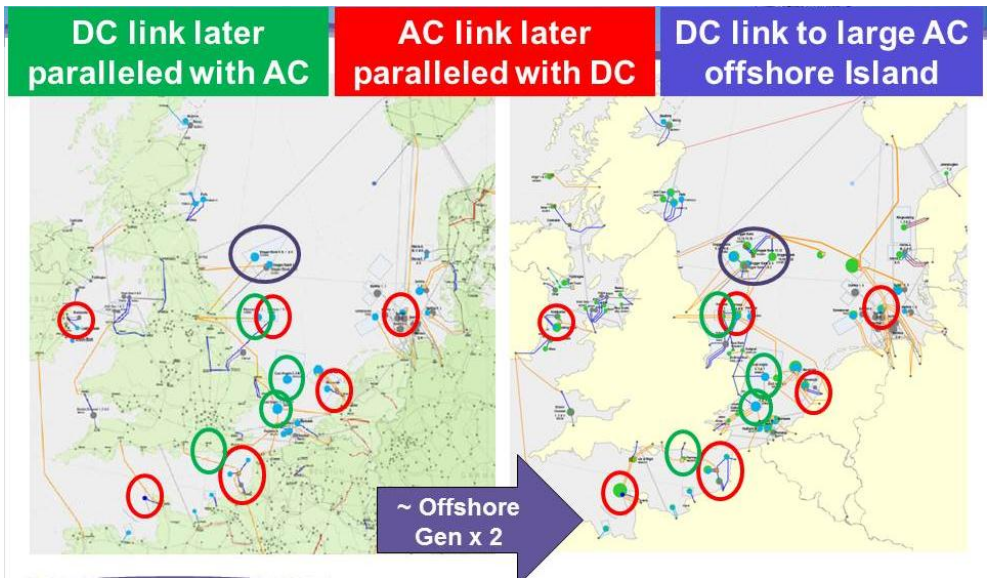
Looking at the NSCOGI findings as a development from today's projects to a meshed offshore grid, a definition of "meshed" has to be given: This can be answered by reading the "meshed" solutions from both scenarios as a development. Starting from the Reference scenario, there are all kind of projects: classical DC interconnections, classical AC interconnections and offshore wind power plants connected by AC or DC.

When doubling the amount of offshore generation for the sensitivity analysis, it can be seen that there are three main developments:

- DC links which later are paralleled by AC (green circles)
- AC links which later are paralleled with DC (red circles)
- DC links to large AC offshore islands (blue circles)

This shows that all possible solutions which are used today, be it AC or DC for either integrating offshore wind or for interconnections are a way of integrating the four synchronous areas towards a meshed solution.

Thus a meshed solution can be AC or DC or a combination of both. It can be inside single projects combining one offshore wind power plant to one interconnector but it can also be seen from a system wide perspective like visualized in the picture below.



Summarizing:
Comparing the input data from the NSCOGI scenarios and the ENTSO-E visions, NSCOGI concluded that at this stage a new and comprehensive offshore grid study like the one published in winter 2012 would not lead to fundamental new findings, but only lead to a variant of what already has been found during the last study. Thus, since 2013 the primary focus of NSCOGI shifted to the regulatory/ market and to the permit work stream.

Looking at a possible development, all kind of today's solutions will be part of a later meshed solution.

8. Icelandic Grid

8.1 Iceland

In 2013 the total energy feed-in to Landsnet's transmission system was 17.478 GWh where 70% came from hydro power plants and the rest from geothermal power plants. Thus Iceland produces only renewable electrical energy apart from few micro diesel generators in rural areas, less than 0.1%. Today Iceland only has hydro and thermal power plants but feasibility studies for wind power production have shown very promising results. The study used two 900 kW wind turbines that produced around 6 GWh the first year with an average efficiency of 40%.

Landsnet is planning to start later this year to build its first overhead transmission line since 2007 apart from a 5 km connection to the newest hydro power plant established this year. The line will be 220 kV and strengthen the connection between the southwest area of Iceland and the capital. Other transmission lines in the pipeline consist mainly of few relatively short 66 kV underground cables.

The growth in electricity consumption in Iceland will mostly be due to new silicon and silicon carbide manufacturers as well as data centres that require high processing power. The main challenge in the Icelandic grid development is still to reinforce the central transmission system in order to minimize transmission restrictions between regions.

9. List of figures

10. List of tables

11. Terms/Glossary

3rd Package	3rd legislative package
AC	Alternating Current
ACER	Agency for the Cooperation of Energy Regulators
BALTSO	Regional cooperation between the Baltic TSOs
B2B station	Back-to-Back station. Connects two AC grids at different frequencies or phase counts
CBA methodology	Cost Benefit Analysis methodology
CGS	Combined Grid Solution. Used in the Kriegers Flak project
DC	Direct Current
EC	European Commission
EEPR	European Energy Programme for Recovery
ENTSO-E	European Network of Transmission System Operators for Electricity
GTC	Grid Transfer Capability
HVDC links	High Voltage Direct Current connections
IEA	International Energy Agency
KPI	Key Performance Indicator
NGDP	Nordic Grid Development Plan
NREAP	National Renewable Energy Action Plan
NSCOGI	North Sea Countries Offshore Grid Initiative. Regional group in ENTSO-E
NTC	Net Transfer Capacity
OHL	Overhead Line
PCI	Project of Common Interest (Projects adopted by the European Commission)
RegIP	Regional Investment Plan
RES	Renewable Energy Sources
RG BS	Regional Group Baltic Sea

SEW	Social and Economic Welfare
SoS	Security of Supply
TSO	Transmission System Operator
TYNDP	Ten Years Network Development Plan
UCTE	Union for Coordination and Transport of Electricity
VSC	Voltage-Sourced Converter. The newest cable technology
WEO	World Energy Outlook