WHEN TRUST MATTERS

Potential for a Baltic Hydrogen Offshore Backbone

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7th of March 2024

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The Northern Baltic States (especially Finland and Sweden) provide a significant opportunity for hydrogen to be produced for export to Central Europe…

Significant potential for green hydrogen production exists in the Northern Baltic states:

As the scenarios show, there is a potential in the Nordics for hydrogen production for export. Depending on the scenario, in 2050 this ranges from 70 to 119 TWh_{el}. The later would equate to approximately 68 TWh of hydrogen.

The analysis nevertheless illustrates how dependent this production potential is on the national energy plans in the respective countries. For Sweden and Finland, we consider the potential could even be higher if there were more ambitious plans to produce electricity for the purpose of exporting hydrogen.

The economics show a significant variance in the cost of hydrogen production when considering directly connected RES versus taking electricity directly from the grid:

Given that the region already runs on a very high share of renewable and low carbon electricity supply, electrolysers in many Nordic regions could operate with electricity directly from the grid in the near future. This enables a much lower levelised cost of hydrogen, which makes the region as a whole very attractive for low-cost hydrogen production.

The high renewable share needs to be maintained in order to enable producers to work with power directly taken from the grid in conformity with the RED II criteria.

The transportation of hydrogen from the Nordics can be carried out by a combination of offshore and onshore pipelines:

An onshore pipeline route via the Baltic States alone is not enough to transport the expected surplus hydrogen from Finland to Germany and Poland after 2030. As both countries have huge hydrogen demands in the future

The analysis shows that the combination of an offshore and an onshore pipeline offers advantages in terms of diversification of supply. Nevertheless, an optimized offshore pipeline, which also could connect Poland, would be sufficient and more cost effective for the transport of the calculated 62 TWh hydrogen in the optimistic scenario this study develops. The cost of such an optimized pipeline are estimated at 6,5 billion Euro.

Executive Summary (2/2)

….but these countries have not made the necessary provisions to make the region a significant net exporter. A joint strategy with large offtake regions needs to be developed.

The north European countries should seek an alignment on how they could strategically produce a significant share of (green) hydrogen domestically:

We recommend a strategic dialogue between the countries bordering the Baltic Sea and the countries of the EU that are dependent on hydrogen imports (especially Germany and Poland). The aim should be to develop a joint strategy and vision for a hydrogen network in the Baltic Sea region that develops the previous ideas in the discussions on a European hydrogen backbone and firms up the plans for RE expansion, pipeline planning and industrial use. Due to the many aspects that need to be considered, a multinational agreement for such a hydrogen production and network expansion would be necessary.

A joint planning of electricity and hydrogen production is an important next step:

For a refinement of the analyses, we recommend an integrated system modelling, that provides an optimization based on hourly dispatch, which we did not perform in this study. Such modelling is recommended as the next stage of refinement, to better understand how the future electricity and hydrogen markets will interact and affect each other.

1. Introduction

Strategic diversification of hydrogen supply for Europe will be key for a secure decarbonisation. Northern Europe has large renewable energy production potential and local hydrogen production can bring important energy security benefits to the region.

Introduction

With rising temperatures and more extreme weather events there is a need for huge steps in decarbonisation around the world. Wherever possible energy saving and electrification by means of renewable energy are the two best ways to reduce GHG emissions. But in some areas, this might not work, as processes demand dense energy supply and/or energy availability in large amounts independent from a power grid.

For these reasons, green hydrogen is particularly needed in industrial centres in Central Europe to decarbonize key industries such as steel manufacturing. However, the supply of decarbonized hydrogen is a challenge, as it often cannot be produced in sufficient quantities directly in the vicinity of the consumption centres, since in these areas the spatial potentials are limited and the production conditions for renewable energies are not optimal.

Consequently, there is a need for Europe to transport decarbonized hydrogen from various sources to the centres of hydrogen demand. European demand for hydrogen is estimated to be around 2,400 TWh in 2050, according to the European Hydrogen Backbone initiative.

The hydrogen will ideally be produced in regions that:

- Specifically allow for low hydrogen production costs (expressed as levelized cost of hydrogen / LCOH), and
- Have close geostrategic ties with the EU and NATO in order to reduce Europe's dependence on potentially critical supply partners.

Many potential sourcing options involve very long transport routes. In addition, with a global ramp-up of hydrogen demand, competition for these far-flung production facilities will also establish itself in the long term, so that **domestic European hydrogen production** on a significant scale represents a strategically sensible supplement to imports.

Focus of this study

European hydrogen production can be set up very well in the southern countries of Europe, especially in countries like Spain and Portugal, due to very good solar resources. But it can also be established in the North Sea area and in the **Scandinavian countries**, where wind conditions are good. This study takes the results of the previous study “Specification of a European Offshore Hydrogen Backbone” and deepens them for the Baltic Sea region.

In the previous study, the aspect of determining the production potential for the Baltic Sea region was not the focus of the investigation – this gap is closed with this study. **This analysis focuses therefore on the potential for hydrogen production in the Baltic Sea region, especially in Sweden and Finland.** These Scandinavian countries could potentially offer good conditions in this context. Both countries only have a small share of fossil electricity generation and are already generating electricity primarily from low carbon sources such as hydropower, renewables (mainly wind) and nuclear energy. In addition, the large and sparsely populated areas in both countries provide a significant potential for additional on- and offshore generation from wind energy sources.

Hydrogen production from renewable energies could therefore potentially be less in conflict with the use of electricity generation for electricity demand, although this will depend on national renewable energy plans. Being part of the EU and, in the case of Finland, NATO, these countries are also ideal cooperation partners. Lastly Scandinavia has, next to its wind resources, the advantage that it is not affected by droughts like the southern countries, so that water is more easily available as a starting point for electrolysis.

This study aims to show whether there is sufficient potential in the Baltic Sea region for hydrogen production for export and, if so, how the countries can significantly benefit from the development of a hydrogen network and the corresponding trade in hydrogen. For large-scale export of hydrogen, pipeline systems can play a crucial role, and so the study also provides analysis on potential pipeline routings.

1. Introduction

Any form of hydrogen production will compete with direct electrification, and in DNV's view there is a need to strike the right balance between these two energy vectors.

DNV's viewpoint

Where decarbonisation through direct electrification of a sector is feasible, this is the first priority due to the inefficiencies of converting electricity to hydrogen. Where electrification is not an option — or a very poor one — then hydrogen may be the best alternative, as is the case in many so-called hard-to-abate sectors, like aviation, shipping, and high-heat industrial processes. Hydrogen will also be used in making sustainable end products (e.g. ammonia/fertilisers), green materials (e.g. steel and aluminium), and low-carbon chemicals (e.g. methanol and plastics), many of which could be utilised as fuels for long distance or heavy-duty travel.

Both hydrogen and electricity are an important part of the energy transition, and they are also linked. Some 80% of energy professionals that DNV has surveyed believe that hydrogen and electrification will work in synergy, helping both to scale up[1]. Neither solution can provide the full energy demand given limitations to the amount of renewable power available, as well as the diminishing cost-benefit of grid expansion in the case of extensive electrification. In certain European countries, where a dense natural gas distribution infrastructure is already in place, hydrogen can be delivered to end users by existing gas distribution networks at lower costs than a wholesale switch to electricity.

DNV's main Energy Transition Outlook forecast is that hydrogen (and derivatives) will constitute 11% of Europe's total energy mix in 2050, at 37 million tonnes (approximately 1,200 TWh) of hydrogen per year. In DNV's pathway to net zero (PNZ) scenario, hydrogen use in 2050 is 122 million tonnes (approximately 4,000 TWh) – over three times higher.

Boundary conditions considered in this report

- There is large potential for renewable energy generation in the Baltic Sea and the surrounding countries.
- There is a need for EU domestic production of hydrogen, as outlined by the European Commission.
- There are limits to the extent Europe can cost-effectively electrify, due to grid expansion constraints.
- There is competition for land-use onshore as well as offshore.

Statements

Taking DNV's viewpoint into consideration, together with the boundary conditions, some conclusions are drawn:

- The sea area in the Baltic Sea is different from the North Sea because the distances to coastlines are far shorter and the water depths vary much more. Therefore, the conclusions we provided in the previous report for the North Sea cannot be directly applied to the Baltic Sea.
- The sea and land area required for renewable energy generation to produce hydrogen might also be needed for electricity production to support direct electrification. **This report explicitly does not compare this competitive use of space** in these cases and does not provide a general statement on what to prioritise.
- The actual realisation of hydrogen production will critically depend on decisions of national governments, striking a balance between direct electrification and hydrogen by announcing additional areas that are dedicated to energy production, setting hydrogen production targets and enabling legislation, as well as hybrid- or hydrogen based tender structures.

1: DNV (2021) *Rising to the Challenge of a Hydrogen Economy*.

1. Introduction

The analysis of the report looks at the technical production potential for hydrogen in the Baltic Sea area (mainly Sweden and Finland), the associated production cost and possible routing options to transport hydrogen to Central Europe.

Logic of the report

This report uses the following logic in its analysis:

- First, hydrogen is widely recognised as a valuable part of Europe’s energy transition, with both EU and German hydrogen strategies envisioning widespread hydrogen use to decarbonise industry and other sectors, alongside extensive electrification. Hydrogen use will therefore increase over the coming years as we will show.
- Second, there are clear energy security benefits from producing hydrogen in Europe, using European renewables. Undoubtedly, there will be imports of hydrogen and derivative fuels from other parts of the world, but as the current energy crisis is showing dramatically, Europe needs to reduce its reliance on energy imports from potentially unreliable countries. In addition, European hydrogen production transported through pipelines will have a lower greenhouse gas footprint than hydrogen imported from further afield, as it does not require the shipping and liquefaction or derivative processing steps. Europe should therefore seek to produce hydrogen in larger quantities on its own.
- Third, the potential energy generation from on- and offshore wind in the Baltic area is large, and possibly greater than the electricity system alone can handle. In certain circumstances, producing hydrogen from electrolysis can be a cost-effective and practical way of utilising Northern Europe’s vast wind resources.

The aim of the study is therefore to investigate the practical possibility to set up hydrogen production in the Baltic region and develop an offshore hydrogen pipeline backbone that integrates this production in an efficient way into the European energy system, so that the economic and technical potential of hydrogen production in the Baltic area can be achieved.

Reading instruction

The aim of the study is to estimate the production potential and regional captive demand in Scandinavia and the eastern Baltic Sea countries and to determine the benefits of a Baltic Sea backbone for the hydrogen supply of Central Europe, including Germany and Poland.

This study analyses the potential of the offshore backbone in four main steps.

Chapter 2: First, the hydrogen production potentials in Sweden and Finland are analysed and the respective captive requirements are subtracted accordingly. As a second step, the production potentials and offtake requirements in Estonia, Latvia, Lithuania, and Poland are evaluated. In addition, the hydrogen production potential in the Baltic Sea from offshore wind is analysed. The analysis is mainly based on existing country strategies and roadmaps.

Chapter 3: Next to the surplus potential that can be obtained, the production costs matter. In chapter two we will therefore detail the various green hydrogen production costs in the Baltic area.

Chapter 4: Based on this estimate of the hydrogen export potential from the different countries analysed in chapter 2, the potential transport options to Central Europe, including Germany and Poland, are evaluated and compared. In particular an offshore hydrogen network connecting the neighboring countries of the Baltic Sea and an onshore alternative from Finland via the Baltic States are compared. This evaluation will consider both an estimation of the costs for either option, as well as a detailed assessment of the advantages and disadvantages of either option. Furthermore, we assess whether the export potential in the region will be large enough to justify an offshore hydrogen backbone in addition to a Nordic-Baltic onshore hydrogen corridor from Finland via the Baltic countries and Poland to Germany.

Chapter 5: Finally, we will provide recommendations for further steps to be taken in order to develop the identified potential.

Appendices: Abbreviations, levelised cost calculation methodology, offshore wind areas dataset description, assumptions and input data to the various analyses.

2.1 Introduction and assumptions for surplus analysis

This chapter provides an analysis of the potential for surplus renewable electricity to be used to produce hydrogen for export in the respective countries – Sweden, Finland, Estonia, Latvia, Lithuania and Poland…

In this chapter we show the starting points and likely developments of the energy balances in the Nordic countries Sweden and Finland, the Baltic States and Poland.

We determine in this chapter the potential for surplus renewable electricity generation that could be used to produce **green hydrogen** for export in the countries under investigation. Three-time horizons (2030, 2040 and 2050) are analysed for this purpose.

Note that by "surplus", we mean renewable electricity generation exceeding the local electricity demand and the domestic need of green hydrogen.

The starting point for the forecast is each country's energy balance in its current shape. To determine future developments, we consider various aspects such as the official target on renewable energies issued by the respective governments, targets for electrification and targets for the domestic production of green hydrogen. A special focus is given on the areas of renewable energy expansion. In a methodically identical approach for all countries, the respective developments are forecasted especially based on:

- ENTSO-E & ENTSO-G Ten-Year Network Development plan (TYNDP) in 2022.
- Local energy targets, which will be specified per country in the text.
- Databases on current and planned renewable projects in the respective countries, also applying regionalization within a country.

The analysis combines a top-down approach, considering the country targets, with a bottom-up analysis that is chosen to determine the regionalization of future add on capacities.

From this, a surplus calculation is drawn up for each country, which determines the electricity in TWh that would be available to produce H2 for export in the respective country. Two scenarios are specified (conservative and optimistic). This surplus electricity production of course could also be used to export electricity to neighboring countries. For the purpose of this study we assume that this surplus will be used for the production of hydrogen – given that hydrogen will be needed to met net zero targets.

As the locations matter to determine potential pipeline routings, we take the NUTS 2 codes of the respective countries into consideration to detail the analysis for each country on a more regional level.* This regionalization is needed in order to determine which areas will likely be the sources for a H2 production as they likely will be the ones with electricity generation overcapacity. This regionalization is not in line with e.g. the current bidding zones in countries like Sweden. Its main purpose is to serve as an important input to the suggested pipeline routing. For this study we have disregarded the price incentivization aspects and also the interdependencies between electricity incentivized plants and H2 incentivized plants. We have as a simplification taken the current regional distribution as a starting point and used this distribution pattern for the future buildout as given.

A more detailed description of the assumptions taken can be found in the appendix of this report.

One essential graph will be provided per country. It displays the energy balance and the surplus potential as a waterfall diagram. This diagram aggregates the power supply side (renewable and conventional). From the power supply, we then subtract the electricity demand, making the future demand for electricity in local hydrogen production explicit (see next slide), and then shows either a potential electricity surplus that could be used for producing hydrogen for export (or a need for electricity/hydrogen import).

This analysis is provided for all countries in two scenarios with three-time horizons (2030, 2040 and 2050), and as an additional step for each country regionalized on a NUTS 2 level.

* NUTS classification - German Federal Statistical Office (destatis.de) The nomenclature of territorial units for statistics (Nomenclature des Unités territoriales statistiques – NUTS) is a geographical system, according to which the territory of the European Union is divided into hierarchical levels. The three hierarchical levels are known as NUTS-1, NUTS-2 and NUTS-3. This classification enables cross-border statistical comparisons at various regional levels within the EU. NUTS-2 regions usually have between 800,000 and 3 million inhabitants.

2.1 Introduction and assumptions for surplus analysis

….this information is critical to determine how much electricity would be available to produce hydrogen for export, i.e., the surplus electricity available to realize a hydrogen export. The analysis covers the size, timing and location of the potential surplus.

Conditions for a surplus: The main assumption in our surplus analysis is that a country can only have a surplus for hydrogen (on a net basis) under two conditions: 1) The country's renewable targets have been fulfilled, i.e., the national renewable electricity generation exceeds the national renewable electricity demand according to the RES-E target*, and 2) the domestic electricity demand for green hydrogen is prioritized before any renewable electricity is made available for producing hydrogen for export. Concerning the latter, we proceed as follows.

Country hydrogen demand analysis: To determine a country's national demand, we start by analysing the current demand which is predominantly in the industrial sector. Subsectors analysed include iron & steel manufacturing, ammonia and high value chemicals production, refining, and industrial process heat. As can be seen from the graph on the right-hand side, the largest current hydrogen demand in the considered region can be found in Poland and Finland, and refining and ammonia production have by far the largest share.

In the next step, we assess the future electricity demand for domestic hydrogen potential. We assume here that for all countries grey hydrogen demand will be phased out and replaced by green hydrogen. Also, additional hydrogen demand, e.g., emerging from the transport sector is assumed to be green.

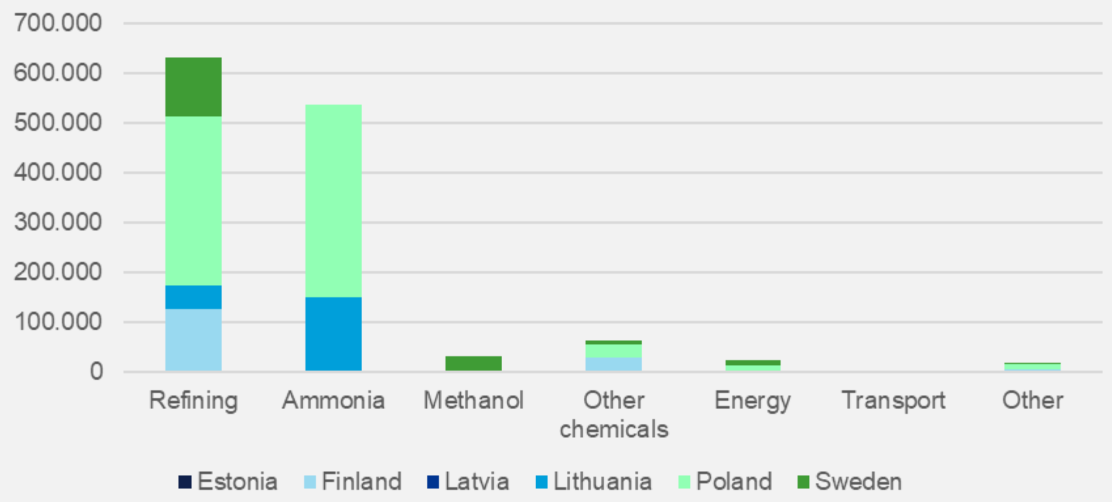
Considering official documents such as a country's hydrogen strategy, assumptions are made across all countries as to which sectors will use hydrogen (instead of or alongside electrification). The categorization of sectors is in line with the TYNDP'22, and includes the sectors industry, transport, residential, tertiary, energy, and other demand.

Regionalization of hydrogen demand: In the final step of the hydrogen demand analysis, we allocate the previously determined national hydrogen demand per industry, transport and other demand sectors to the NUTS regions per country. Allocation factors differ per country as information on e.g., distribution of industry across countries is not homogenously available across the considered set of countries. For the case of Finland, for instance, the national hydrogen demand in the industrial sector has been allocated based on a five-year average of energy use in industry per NUTS 2 region, whilst transport demand has been allocated to Finland's NUTS 2 regions according to statistics on traffic performance for road transport, information on passenger numbers & cargo for aviation and shipping, and passenger numbers for rail transport. For a full overview of allocation factors used per country, see 'Annex: Regionalization of Hydrogen Demand on NUTS-level'.

On the following slides we will detail the hydrogen export potential in this sequence: Sweden, Finland, Estonia, Latvia, Lithuania and Poland.

* RES-E target: Targeted share of Renewable Energy Sources (RES) in the final electricity consumption.

Current estimated Demand by area in Baltic region (metric tons)

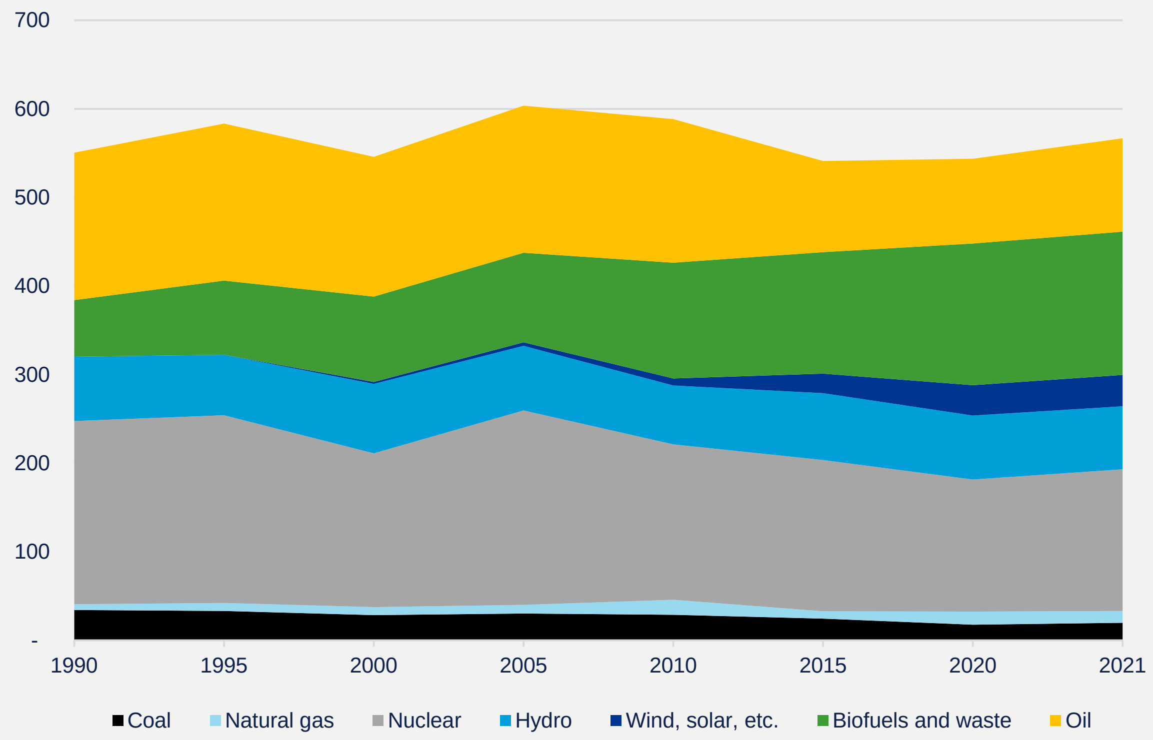


Source: FCHO estimations

2.2 Sweden Hydrogen surplus analysis 2030-2050

Over the last 40 years, Sweden has dramatically reduced its oil consumption, mainly replacing this by nuclear and biomass. With both coal and gas accounting for small shares of the energy mix, low-carbon sources already constitute around 70% of Sweden's energy supply.

Total energy supply (TES) by source in Sweden, 1990-2021 (TWh)



Source: IEA (2022)

Historic development of Sweden's energy system

Sweden's energy system has undergone significant changes over the last decades. Over the last 40 years, the supply of biomass has tripled while fossil fuels have been cut down by half. These changes have been mainly driven by high fossil fuel taxes, a carbon dioxide tax and a program of nuclear development. Nuclear energy plays a major role, since its implementation in the 1970s, as it complements hydropower generation for the electricity sector.

However, the last 15 years have witnessed a growing development of wind capacity. The total energy supply in Sweden has been stable over the years, oscillating around 550 TWh.

Electricity generation in the coming decades

Sweden does not have a fixed target for installed capacities in the power sector. The Swedish government believes that it is more cost efficient to deploy technologies which the market finds most profitable. Nevertheless, by 2030, the share of renewable electricity is projected to be around 75%. By 2040 the share is expected to be around 80%; when nuclear power is included in the calculation, fossil-free electricity production will account for around 99%. Wind generation is expected to grow rapidly, especially offshore, resulting in a combined electricity generation of 77.3 TWh by 2030 (77.00 TWh onshore; 0.3 TWh offshore) and 129 TWh in 2050 in the low electrification scenario of the Swedish Energy Agency (108 TWh onshore; 21 TWh offshore). In its high electrification scenario, wind generation accounts for 179 TWh in 2050 (122 TWh onshore; 57 TWh offshore).

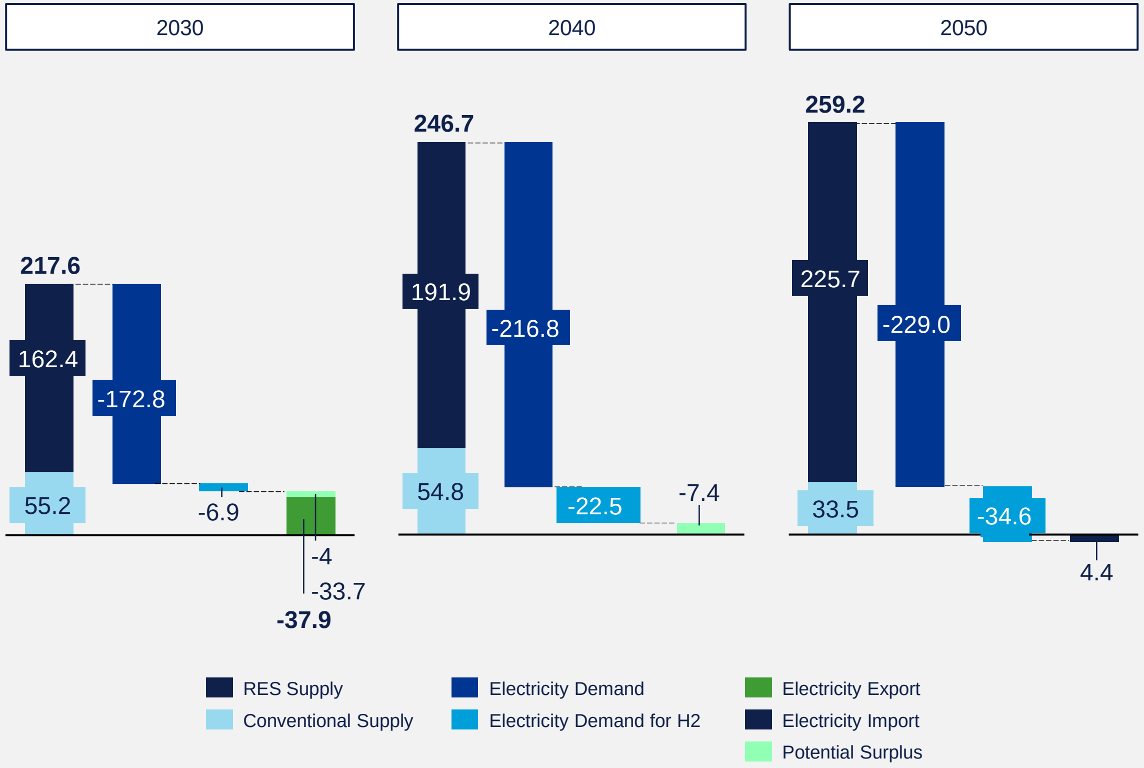
Role of hydrogen towards carbon neutrality

Green hydrogen is expected to help Sweden reach net zero emissions by 2045 by decarbonizing hard to abate industries. The Swedish 2021 hydrogen strategy sets concrete targets for 2030 and 2045: 5 GW and an additional 10 GW of electrolyser installed capacity, respectively. The total hydrogen use in the scenarios for industry is largely linked to a few major players. The need for electricity to produce hydrogen is estimated at 22-100 TWh in 2050.

2.2 Sweden electricity surplus analysis 2030-2050

In the **conservative scenario**, there is a potential surplus in 2030 and 2040 in Sweden, as the RES supply grows more slowly than demand for electricity and local hydrogen production.

Electricity and Demand Supply projections incl. Potential Surplus for green hydrogen production in TWh – Conservative Scenario



Source: DNV

Lower Electrification

The **conservative scenario** illustrates a lower potential surplus for electricity use in hydrogen export. The demand and the supply is based on the “Lower Electrification Scenario” published by the Swedish Energy Agency (SEA). It is based on current policies at the time of publication and aligns with electrification trends in both the Nordic countries and the EU. In contrast to the SEA’s Higher Electrification Scenario, this framework anticipates certain barriers emerging by approximately 2030. These include constraints on the speed of grid expansion and electricity production to satisfy the increasing electricity demand, thereby decelerating the transition to electrification. Additionally, there is no expansion in iron ore extraction (especially relevant for North Sweden), which subsequently reduces the electricity needed for hydrogen production via electrolysis for direct iron pellet reduction. Consequently, fewer electrofuel production projects are initiated compared to the Higher Electrification Scenario.

Slower transformation of the transport sector

In the SEA’s “Lower Electrification Scenario”, the pace of electrifying the transport sector is reduced, predominantly impacting road transportation, which accounts for the bulk of domestic energy consumption. This slower adoption results in fewer rechargeable vehicles, such as plug-in hybrids and fully electric cars, being introduced into road transport. In this scenario, the existing CO2 regulations are maintained, but the degree of vehicle fleet electrification lags behind what is projected in the SEA’s Higher Electrification Scenario.

Replacement of RES target by fossil-free target

The renewable targets applied are based on the updated NECP for the year 2030 and 2040. For 2050 the target is set according to the statement that the demand itself will increase, but not the amount of RES. Unlike the previously submitted NECP, the targets are not based on the RES-share but on fossil-free targets. This also includes potential new nuclear power plants which are currently under discussion.

The depicted hydrogen demand is mainly based on the “Distributed Energy” scenario of the TYNDP 2022 and foresees a steep increase until 2050. However, this increase is lower than in the TYNDP’s “Global Ambition” scenario. The base data will be allocated and adjusted to the specific NUTS regions in the next stage of the analysis..

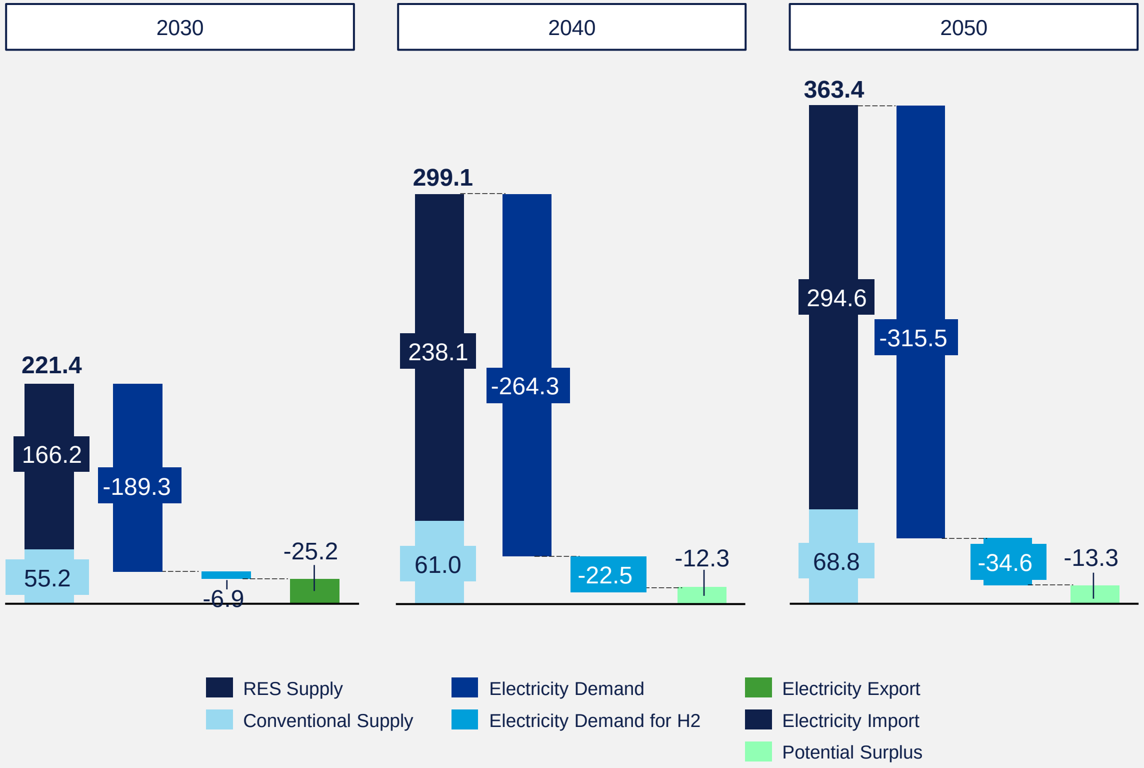
Conclusion

In this scenario, in the long run (towards 2050), Sweden is **not** going to become a potential green hydrogen export source. This is mainly due to significant electrification foreseen in Sweden, which will reduce any current and future electricity surplus.

2.2 Sweden electricity surplus analysis 2030-2050

In an **optimistic scenario**, the potential surplus is at a higher level than in the conservative scenario. Domestic electricity demand, however. will also be higher, based on a higher electrification path and successful electricity grid expansion.

Electricity and Demand Supply projections incl. Potential Surplus for green hydrogen production in TWh – Optimistic Scenario



Source: DNV

Higher electrification = higher surplus
The **optimistic scenario** assumes a higher potential surplus for hydrogen export. The demand and the supply is based on the “Higher Electrification Scenario” published by the Swedish Energy Agency (SEA). In Higher Electrification, extensive electrification takes place in Swedish society as part of the energy transition to achieve the climate targets. In this scenario, the development of electrification in the Nordic region and the EU is assumed to be higher than in the SEA’s “Lower Electrification” scenario. In the industrial sector, electrification takes place as industries convert their production establish new electricity-intensive activities. A higher demand for products that are sustainably produced or contribute to the climate transition leads to further increased industrial production of, for example, fossil-free steel, electrofuels and batteries. These goods are electricity-intensive to produce, so electricity use increases significantly. More carbon capture projects are also included. Potential obstacles to the production of new electricity like grid expansion and bottlenecks of material supply are assumed to be resolved.

Electrified transport
The SEA’s Higher Electrification scenario involves a higher rate of electrification in the transport sector; this mainly affects road traffic, where energy use in domestic transport is greatest. A higher rate of electrification means a more rapid introduction of rechargeable vehicles (plug-in hybrids and fully electric vehicles) in road transport (and related infrastructure), which increases electricity demand and reduces demand for liquid and gaseous fuels. In this scenario, the potential demand of HDV-FCVs are not considered, as the expected share in the transport sector is zero for the entire timeframe.

New Nuclear contributing to the fossil-free goal
In the Higher Electrification scenario, the demand is also covered by new nuclear power plants from 2040 onwards. The renewable targets applied are based on the fossil-free targets which have been stated as new targets in the updated NECP. The depicted hydrogen demand is mainly based on the “Distributed Energy” scenario of the TYNDP 2022 and foresees a steep increase until 2050. The base data will be allocated and adjusted to the specific NUTS regions in the next stage.

Conclusion
In the optimistic scenario Sweden will have a surplus of green electricity to provide hydrogen exports in 2040, which remains then relatively stable at around 13 TWh in 2050 – Sweden will therefore offer a slight but **not** substantial potential.

On the following slide we explain in more detail how the local hydrogen demand for Sweden has been derived.

2.2 Sweden electricity surplus analysis 2030-2050

Further detail on projections for Sweden’s green hydrogen demand: An increase in green hydrogen demand is expected, although currently it does not play an important role. In the transport sector there are plans to use hydrogen for long distance traffic.

Current production of hydrogen
Presently, most of the hydrogen production occurs near the production sites. A smaller volume of hydrogen is delivered to clients in compressed form by truck. As of now, there is no production of e-fuels or ammonia in Sweden.

Current demand

Hydrogen currently finds its most common application within the refinery and chemical industry sectors in Sweden, where it plays a crucial role in various industrial processes. Looking ahead, there are extensive development plans to expand its usage into other sectors, such as the transport sector or the iron and steel industry.

Transport

Specifically, the latter holds significant potential to decarbonize production processes, thereby contributing to the industry's sustainability goals. Furthermore, the transport sector — encompassing trucks, rail traffic, shipping, and aviation — is also in the process of devising strategies to incorporate hydrogen into their operations. This includes developing hydrogen-powered vehicles (especially Heavy-Duty Vehicles at the beginning, potentially also for shipping and aviation from 2030 onwards) and systems to reduce emissions and align with the country's ambitious environmental objectives.

Storage

The storage of hydrogen will mostly likely be near the users and in the form of conventional hydrogen tanks. The anticipated 5 GW electrolysis capacity by 2030 is projected to need between 22 and 42 TWh of electricity. Given the inherent challenge of ensuring sufficient electricity supply at any given hour, one approach could involve increasing the installed electrolysis capacity and incorporating a storage facility. Such a strategy would enable producers to leverage flexible grid connection agreements and capitalize on periods of lower electricity prices, thereby optimizing production efficiency

Iron & steel

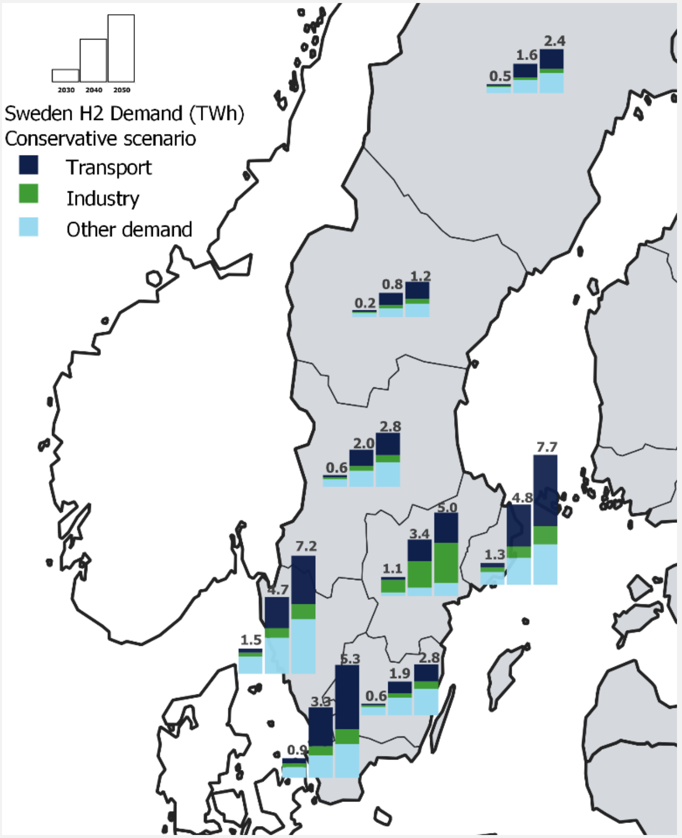
Currently, metallurgical processes only account for around 0.8% of current hydrogen demand. The prospect of leveraging hydrogen or synthetic gas (a blend of carbon monoxide and hydrogen) for the reducing environment for metallurgical procedures is a could be a promising one and would imply an increased utilization of hydrogen in these processes.

Ammonia

The conditions for replacing particulate carbon with hydrogen is now being investigated in a case study with Boliden and their smelting plant in Rönnskär. The potential climate benefit is estimated to be at least 20,000 tonnes of carbon dioxide per year. Ammonia produced from hydrogen and nitrogen could be an alternative to hydrogen in this case. Ammonia is currently used as a reduction agent at the smelting plant in Rönnskär in the production of copper.

Fuel production (refining)

Sweden has two main refineries, one being in Gothenburg and one in Lysekil (North of Gothenburg), both run by PREEM, a Swedish petroleum company. They account for around 80% of Sweden’s refinery capacity. In addition, there are two refineries run by Nynas, which are located in Nynäshamn (north of Stockholm) and near the port of Gothenburg.



Source: DNV

2.2 Finland electricity surplus analysis 2030-2050

Finland's energy system has transitioned from fossil fuels to renewables which, combined with nuclear energy, currently represent about 60% of Finland's primary energy supply. Hydrogen is set to play a pivotal role in Finland's journey towards carbon neutrality by 2035, spanning mainly the industry and transport sectors.

Historic development of Finland's energy system

Finland has one of the lowest levels of reliance on fossil fuels among IEA member countries. The share of fossil fuels in Finland's total energy supply declined from 53% in 2011 to 36% in 2021, mainly driven by reduced oil demand (transport and industry) and a growing use of renewable energy sources.

Legal obligation to achieve carbon neutrality by 2035

Finland aims for carbon neutrality by 2035 through strategies like maintaining nuclear energy, expanding renewables, improving energy efficiency, electrifying sectors, developing new technologies for hard-to-abate sectors, and utilizing bioenergy. Increased carbon removals from LULUCF are expected to offset remaining emissions.

Role of renewables

Renewables provided 53% of total electricity generation in Finland (38 TWh) in 2021, with hydro, forestry biomass, and onshore wind being the main sources. In terms of primary energy, the renewables share reaches 40%.

- **Hydropower** is a major source of generation in Finland's energy system. The share of electricity generation from hydro has varied between a minimum of 16% and a maximum of 24% from 2010 to 2021, depending on annual precipitation.
- Finland has experienced notable growth in **bioenergy and waste**, increasing from 23% of total energy supply in 2011 to 34% in 2021.
- **Wind generation** also saw significant growth, rising from 0.1% to 2.3% of total energy supply from 2011 to 2021.

Role of nuclear energy

Nuclear energy is a central part of Finland's plans to achieve carbon neutrality by 2035 and reduce energy import dependence.

- Finland has two nuclear power plants: Olkiluoto (three reactors) and Loviisa (two reactors). The total installed generation capacity of these plants is 4.39 GW (~36 TWh in 2023).
- Nuclear energy is the largest single source of electricity generation in Finland, accounting for 20% of total energy supply in 2021.

Future role of hydrogen in Finland's energy system

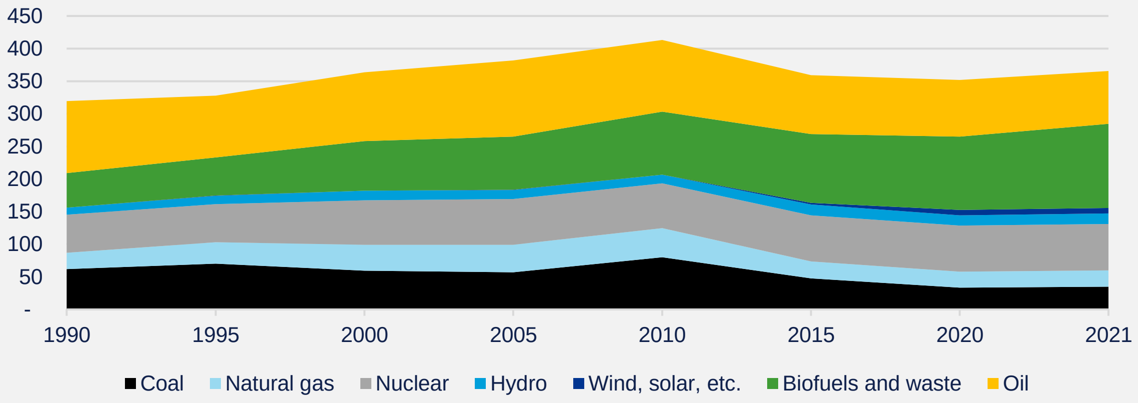
Hydrogen will play a significant role in Finland's efforts to achieve carbon neutrality by 2035. The country recognizes the importance of low-emission hydrogen in:

- Reducing industrial emissions (predominantly steel and refinery industry).
- Reducing emissions in the transport sector (heavy duty, shipping).

Furthermore, Finland acknowledges the importance of hydrogen in power system balancing and aviation, albeit to a lesser extent compared to the above-mentioned sectors.

To support efforts and encourage hydrogen investments, Finland's budget proposal for 2023 includes substantial funding for hydrogen projects. Moreover, Finland promotes the development of clean hydrogen production capacity, setting targets for electrolysis equipment used in hydrogen production. The goal is to reach a minimum of **200 MW electrolysis capacity by 2025** (compared to 9 MW in 2021) and at least **1,000 MW by 2030**.

Total energy supply (TES) by source in Finland, 1990-2021 (TWh)

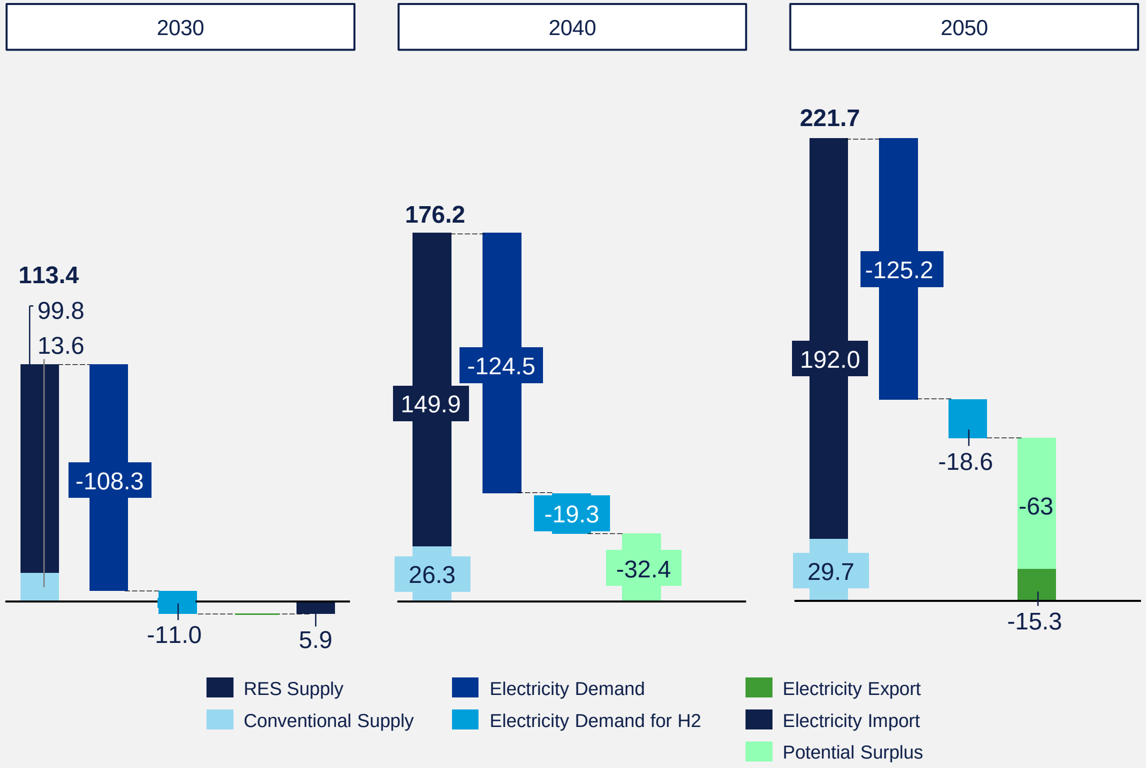


Source: IEA (2022)

2.2 Finland electricity surplus analysis 2030-2050

In a **conservative scenario**, Finland's surplus of electricity available for hydrogen production is projected to reach 30 TWh by 2040 and 78 TWh by 2050.

Electricity and Demand Supply projections incl. Potential Surplus for green hydrogen production in TWh – Conservative Scenario



Source: DNV

Electricity supply
Finland's electricity generation is expected to grow significantly in the coming decades, primarily due to a substantial expansion of wind power generation. Projections indicate that between 2030 and 2050, onshore wind generation will double, from 70 TWh in 2030 to 140 TWh in 2050. Furthermore, offshore wind generation is expected to quadruple during this period, increasing from 5 TWh in 2030 to 20 TWh by 2050.

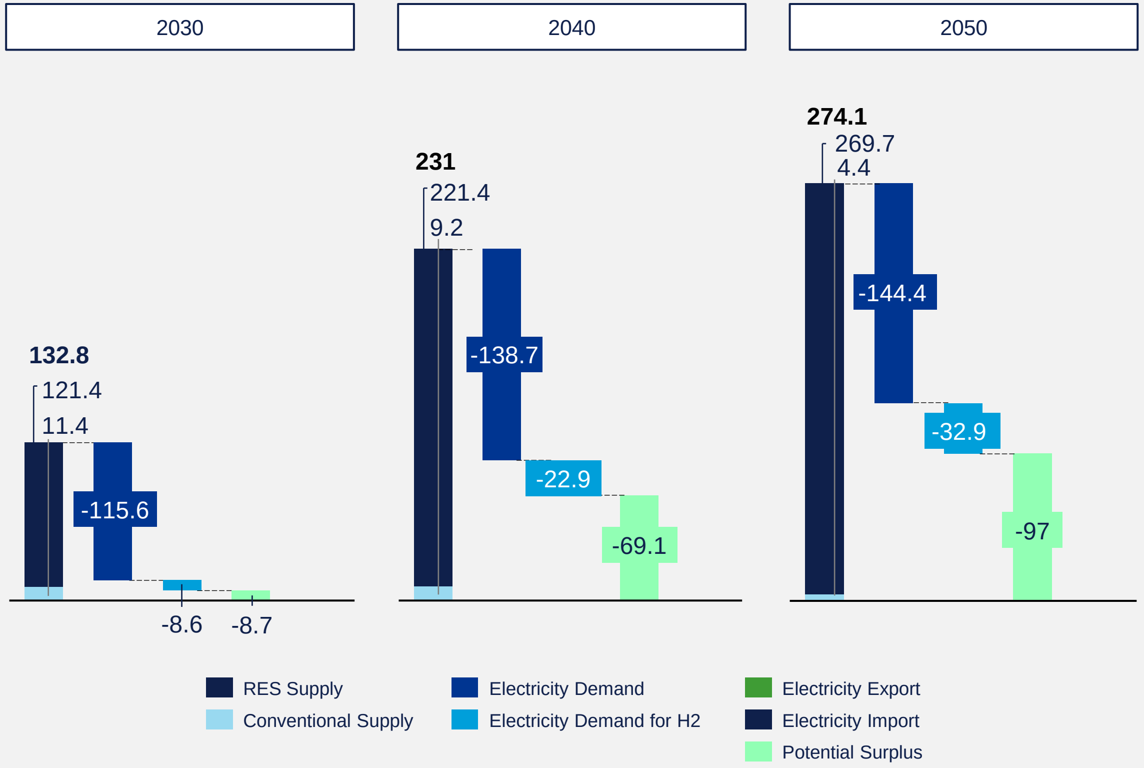
Electricity demand
Based on TYNDP22 scenarios, there is a 20% increase in electricity demand in sectors other than domestic hydrogen production from 2030 to 2040, and this demand stabilizes thereafter. Additionally, the electricity demand for hydrogen production experiences nearly a doubling between 2030 and 2040 and remains stable beyond that period.

Findings
1) Presently, Finland exceeds its RES- targets for 2030 (84% actual compared to 57% target), and it is anticipated to maintain this trend until 2050.
2) In 2040 and 2050, Finland is expected to have an excess of electricity available for hydrogen production, amounting to 30 TWh and 80 TWh, respectively.

2.2 Finland electricity surplus analysis 2030-2050

In an **optimistic scenario**, Finland is projected to generate more renewable electricity than its domestic demand as early as 2030, resulting in a surplus by 2040 (69 TWh) and 2050 (97 TWh) that can make a substantial contribution to hydrogen production.

Electricity and Demand Supply projections incl. Potential Surplus for green hydrogen production in TWh – Optimistic Scenario



Source: DNV

Electricity supply

Like the conservative scenario, the **optimistic scenario** shows a steep increase of electricity generation. In this scenario, wind power generation increases even more. Projections indicate that between 2030 and 2050, onshore wind capacity will more than double, reaching about 200 TWh from 80 TWh in 2030. Furthermore, offshore wind generation is expected to increase by a factor of seven during this period, from about 4 TWh in 2030 to 30 TWh by 2050.

Electricity demand

Similar to the previous scenario, there is also a 20% increase in electricity demand in sectors other than domestic hydrogen production from 2030 to 2040, and this demand increases slightly thereafter. Additionally, the electricity demand for domestic hydrogen production triples between 2030 and 2050.

Findings

1) Already by 2030, almost the entire electricity demand is projected to be derived from renewable sources. From then onwards, Finland’s electricity generation exceeds its domestic RES-E targets, and it is anticipated to maintain this trend until 2050.
2) From 2030 onwards Finland would have an excess of electricity available for hydrogen production. This amounts to about 9 TWh in 2030 and is expected to increase by a factor of ten by 2050.
3) Comparing the domestic surplus electricity generation with the Finnish Government’s analysis outcomes on hydrogen demand for e-fuel and hydrogen export, the surplus in 2040 even exceeds the stated demand for e-fuels export (26 TWh) and hydrogen export (36 TWh) but falls short the Finnish Government’s analysis scenario outcomes in 2050 where an export of 51 TWh hydrogen and 107 TWh e-fuels is mentioned.

On the following slide we explain in more detail how the local hydrogen demand for Finland has been derived.

2.2 Finland electricity surplus analysis 2030-2050

Further detail on projections for Finland’s green hydrogen demand: Overall, hydrogen in Finland's industry is critical for achieving carbon neutrality, primarily driven by the iron and steel sector, while its role in the transport sector is still evolving, with a focus on heavy-duty road transport and potential applications in shipping.

Current hydrogen demand

In Finland, hydrogen is primarily used for oil and biofuel refining, with 88% of its usage concentrated in Neste Oyi refineries close to Helsinki as well as the UPM biofuel production plant close to Turku. **The country produces around 5 TWh of hydrogen annually**, with 99% of it coming from fossil sources, mainly natural gas. Additionally, approximately 1 TWh of by-product hydrogen is generated during sodium chloride electrolysis, and a significant amount is also produced during oil refining, although specific quantities are not publicly available. The steel sector in Finland currently utilizes a small amount of hydrogen, totalling less than 1 TWh.

Future hydrogen demand

Conservative scenario: The Finnish Government's analysis considered "No regret" scenarios, which represent the minimum domestic demand in the industry and transport sectors. These scenarios primarily focus on producing hydrogen and its derivatives for domestic use. The conservative scenario is based on the "No regret B" scenario which predicts that hydrogen's end-use will reach approximately 14 TWh by 2050. In this scenario, the steel industry is expected to account for the largest portion of hydrogen demand, while heavy-duty transport and shipping sectors will require a smaller share.

Optimistic scenario: The optimistic scenario results are shown in the figure on the right, allocated to Finland’s NUTS2 regions. In this scenario, which is based on the “Maximum B” scenario of the Finnish Government’s analysis, the iron & steel industry as well as the transport sector are set to become the largest domestic H2 consumers. Both sectors contribute about 21 TWh of electricity demand for hydrogen production to the total of 23 TWh in 2050.

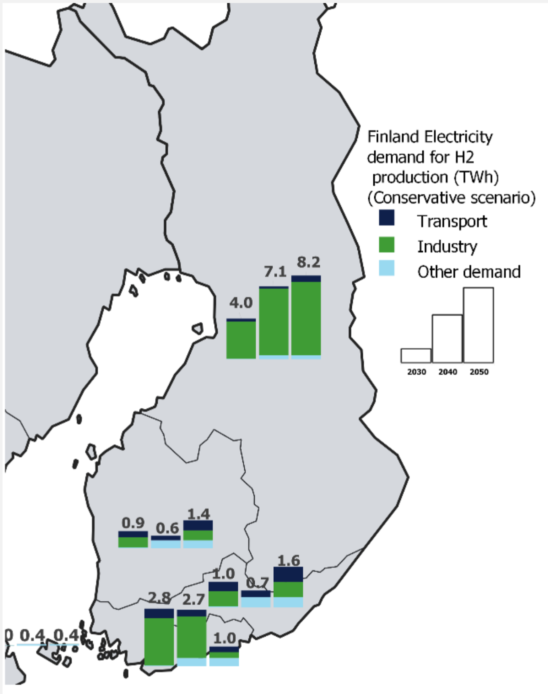
Distribution of future hydrogen demand

The general distribution of hydrogen demand in the transport sector is allocated to the mainland regions where the highest transport concentration is expected, whilst specific demands for shipping are concentrated in the Helsinki and Southern Finland region, where the highest cargo and passenger concentration is expected.

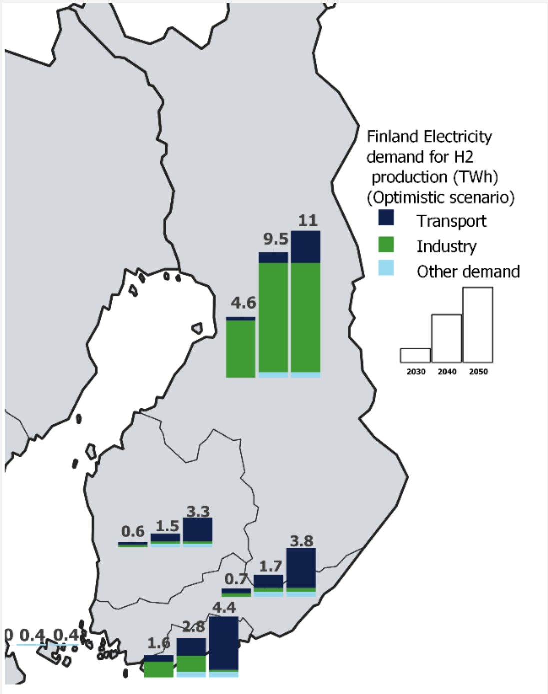
For the industrial sector, most demand for the steel industry is expected to be in the Northern Finland region, where the main steel plant in Raahe has already undertaken concrete steps to apply hydrogen in a direct reduction of iron (DRI) process. Some smaller shares of industrial demand are allocated to the southern regions where the current major refineries are located.

Distribution of projected hydrogen demand per region and sector in 2030, 2040 and 2050

Conservative



Optimistic



Source: DNV

2.2 Estonia electricity surplus analysis 2030-2050

Estonia's energy system is characterized by the intensive use of oil shale, while biomass from domestic forestry is the main renewable resource.

Estonian energy system

The Estonian energy system is highly independent, as it produces most of the energy that is consumed in the country; nevertheless, it also has the highest carbon intensity of all IEA members. Estonia's most relevant primary energy source is oil shale, which is used is for power generation, heat and liquid fuels. The energy system has decreased its dependency on oil, mainly by shifting towards biofuels, more efficient heating systems and other energy efficiency measures.

Renewable energy plans

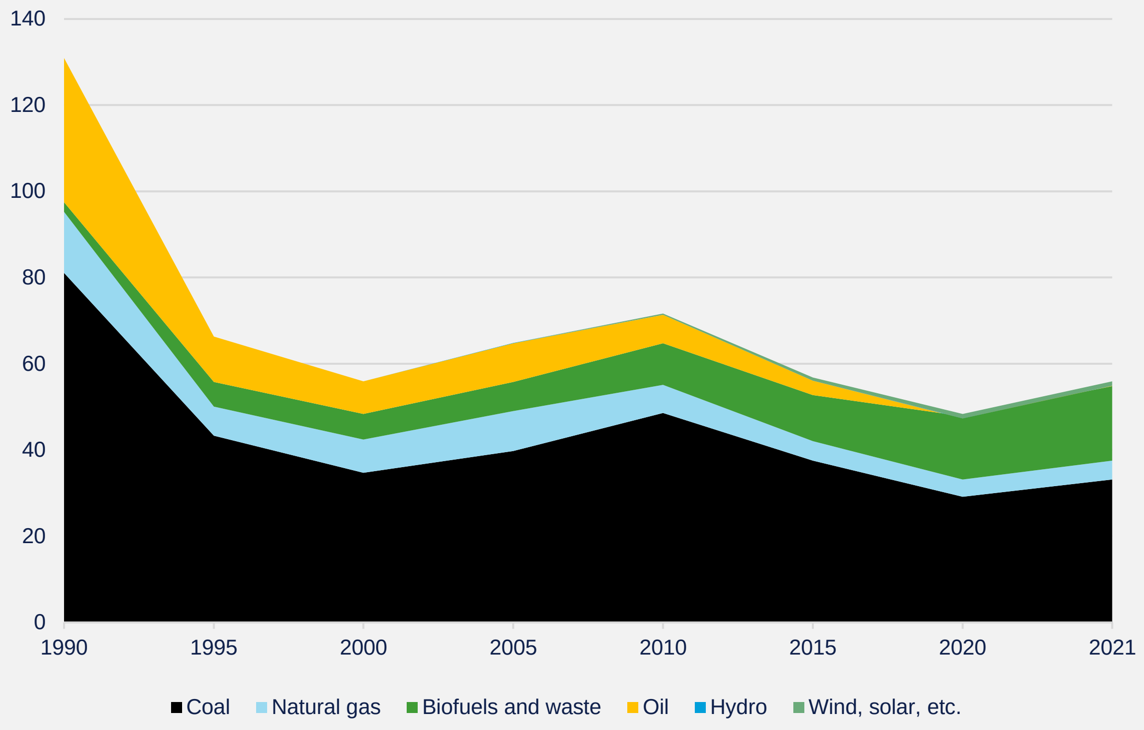
The Estonian National Energy and Climate Plan (NECP) establishes the development of the sector until 2030. In the NECP it is envisioned that electricity generation will be supplied 100% from renewables, which encompasses 9.4TWh of renewable electricity supply. Oil shale is envisioned to be phased out of the energy system by 2040. The complete decarbonization of the Estonian economy is planned to be achieved by 2050, where Estonia plans to be a competitive economy with zero emissions.

The final report "Transition to a Climate-Neutral Electricity Generation", developed by a collaboration among Trinomics, the Stockholm Environment Institute (SEI) and E3-Modelling (E3M), provides insights on how Estonia can achieve zero-carbon electricity in 2050. The study analyses one reference (business as usual) and seven electricity production pathways for Estonia, where the modelling results and a qualitative assessment provide an overview of how the deployment of renewable technologies and flexibility options could kick-in to achieve the aforementioned objective.

Hydrogen development

The latest NECP indicates 50GWh/year of Hydrogen for the transport sector, aligning with the European Parliament´s Alternative Fuels Infrastructure Regulation (AFIR). This supply will be available in 2030 to enhance accessibility to hydrogen refueling stations across Europe's key transport corridors and hubs. Nevertheless, studies carried out by the Tallinn Center of the Stockholm Environmental Institute and the Institute of Chemical and Biological Physics identified larger hydrogen demands in the industry and transport sector. The study "Analysis of the hydrogen resources usage in Estonia" was based on the analysis of secondary data, interviews with experts and market participants. Major differences with the NECP can be found in the projections for final demand for sectors in 2030. The NECP establishes a quota of 0.05TWh/year for transport, while the study quantifies between 1.9TWh/year to 3.6TWh/year for transport, industry, buildings and grid. The study identifies a representative quota of cars, trucks and ferries, and the revival of infrastructure for the storage of ammonia in the port of Sillamäe in Ida-Virumma. The port is one of the ammonia terminals along the Baltic sea region. It includes a pipeline for ammonia transport from Russia, a terminal and storing facilities, which played an important role until 2022.

Total energy supply (TES) by source in Estonia, 1990-2021 (TWh)

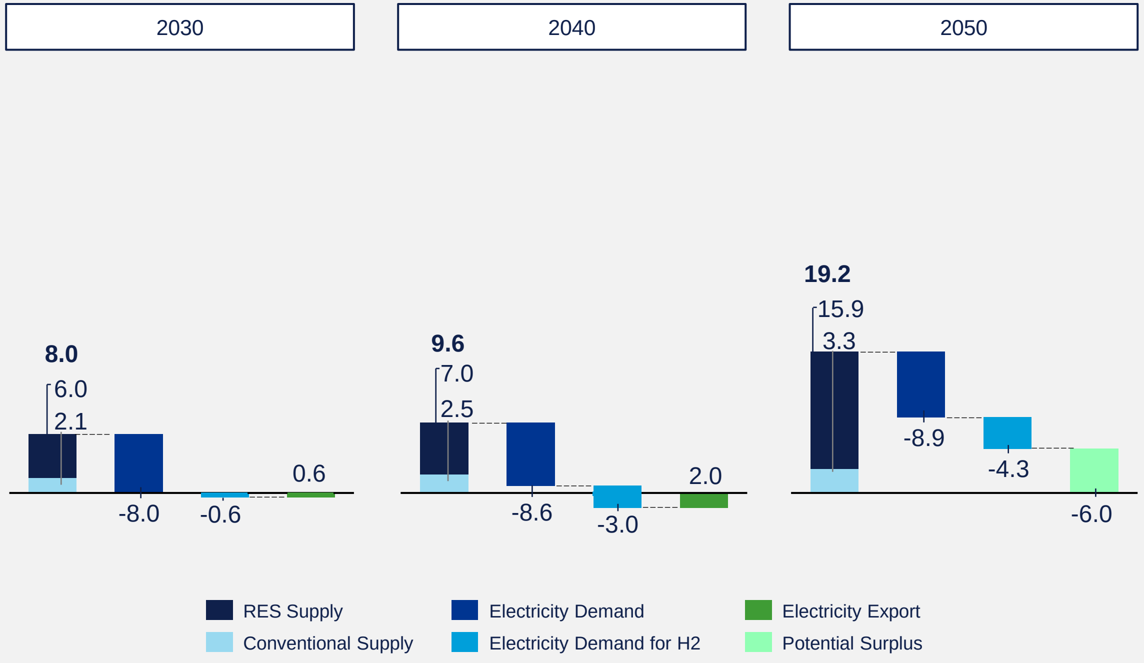


Source: IEA (2022)

2.2 Estonia electricity surplus analysis 2030-2050

In a **conservative scenario**, Estonia is projected to have available surplus in 2050 (6TWh/year), but in 2030 and 2040, the country does not yet have enough generation to cover its national demand, relying on imports to cover the deficit.

Electricity and Demand Supply projections incl. Potential Surplus for green hydrogen production in TWh – Conservative Scenario



Source: DNV

Electricity supply

Energy targets established by the Estonian government for 2030 were recently updated, indicating that the power sector will be 100% renewable. However, to reach the 2030 offshore wind energy goal (3.72 TWh/year), regulatory and environmental barriers need to be addressed and overcome. As of 2023, offshore wind is not part of the Estonian energy system. Thus, our **conservative scenario** aligns with the pathway ”All technologies” of the study “Transitioning to a climate-neutral electricity generation”, where part of the electricity production will be done by oil-shale and imports. In this scenario, the targets for renewable generation will not be fulfilled, and the annual electricity generation in 2030 and 2040 will not be enough to cover national demands.

Electricity demand

Electricity and hydrogen demand are based on the “Global Ambition” scenario from the TYNDP. The electricity demand does not grow much between 2030 and 2050, while a big part of the demand for transport and industry will be covered by hydrogen. Even though the use of hydrogen and its final demand increases in the timeframe, its potential is quite low.

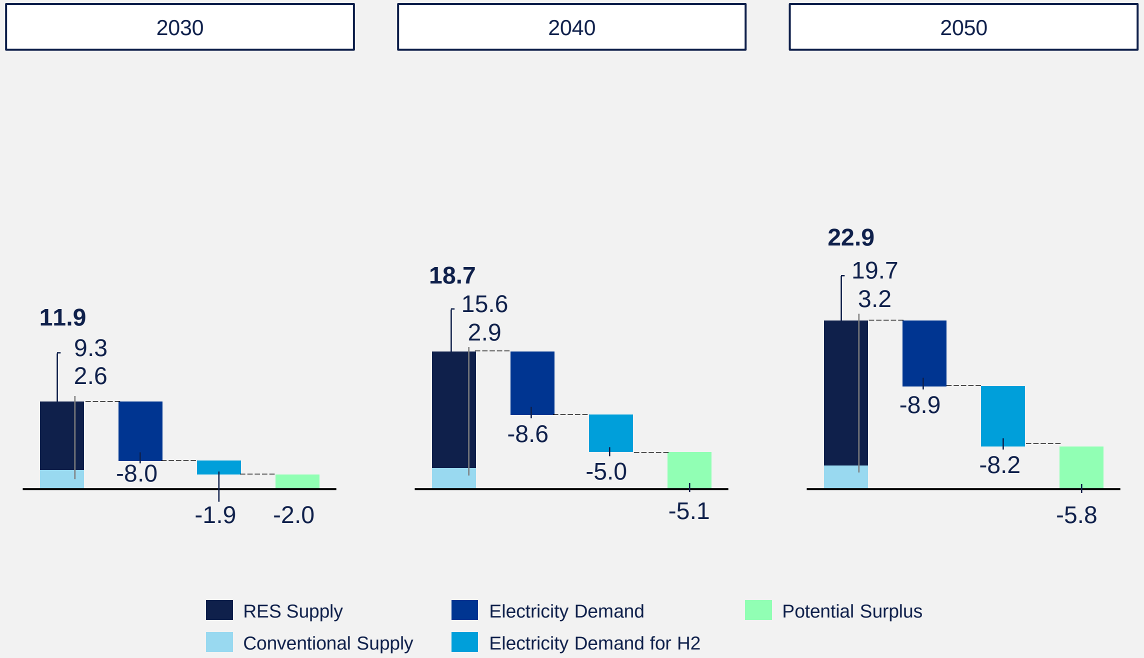
Conclusions

1. Annual electricity generation in 2030 and 2040 grows at a low rate, while demand for electricity keeps constant but with increasing hydrogen demand in industry and transport. Thus, the energy system will likely rely on imports to cover national demands.
2. With the massive deployment of offshore wind energy in 2050, the energy system becomes self-sufficient, covering national demand for electricity and hydrogen, with the potential availability of a surplus.

2.2 Estonia electricity surplus analysis 2030-2050

In the **optimistic scenario** a quick and steep deployment of renewable energies, especially offshore wind, allows Estonia to have an available surplus by 2030. Estonia also develops its hydrogen industry, which can be covered by the projected installed capacity.

Electricity and Demand Supply projections incl. Potential Surplus for green hydrogen production in GWh – Optimistic Scenario



Source: DNV

Electricity supply
The most recent NECP updated by the Estonian Government targets 100% renewable electricity by 2030 in response to the international energy supply changes resulting from Russia's invasion of Ukraine. The study "Transitioning to a climate-neutral electricity generation" provides 7 scenarios of technology roll-out for Estonia in 2030, 2040 and 2050. In this regard, the pathway "Renewable + Storage" highly aligns with the targets for the deployment of the offshore wind sector in 2030. Afterwards, the pathway shows an expansion of the renewable sector driven mainly by the expansion of offshore wind farms. The total amount of renewable energy in 2050 equals 19,69 TWh.

Electricity demand
Demand in the electricity sector is based on the "Distributed Energy" Scenario developed by the TYNDP 2022, in which the demand grows at a higher pace than in the TYNDP's "Global Ambition" Scenario (see conservative scenario on the previous slide). Hydrogen demand is taken from the low scenario of the study "Analysis of the hydrogen resources usage in Estonia". The low scenario envisions the local production of hydrogen in Estonia for final use in the transport, industry, building and power sectors. The main characteristics of the scenarios are the revival of the ammonia terminal for local production and exports, use of hydrogen in the transport sector, mixing of hydrogen for heating purposes at household level and hydrogen-to-power uses in the power sector.

Conclusions
1. The development of the renewable sector is driven by a huge availability of offshore wind from 2030, and complementary generation from onshore wind and solar PV.
2. The internal demand for hydrogen and electricity is covered by local generation throughout the timeframe of this scenario, while a surplus of electricity for hydrogen export is already available from 2030 onwards.

On the following slide we explain in more detail how the local hydrogen demand for Estonia has been derived.

2.2 Estonia electricity surplus analysis 2030-2050

Further detail on projections for Estonia’s green hydrogen demand: The revival and adaptation of the national industry to produce ammonia, and ambitious targets for hydrogen use in the transport sector, will drive the use of hydrogen in the energy system. Nevertheless, the potentials do not align with the policy targets.

Hydrogen prospects
As of 2021, hydrogen is not produced on a large scale in Estonia. Decarbonization paths for Estonia´s energy system focus on replacing oil shale, which is used in the power and heating sector. Hydrogen is envisioned by the Estonian government in the strategy “Estonia 2035”, where a set of sectorial development plans and programs in the respective fields are proposed.

The study “Analysis of the Hydrogen Resources Usage in Estonia”, maps potentials and draft pilot projects to find out which are most prospective from an economic point of view. The study shows that transport sector (road, rail and marine), ammonia & methanol industry, buildings and power sector should be the main targets for possible hydrogen penetration – to unlock such potential 8 TWh (low scenario) to 16 TWh (high scenario) of electricity will be needed in 2050.

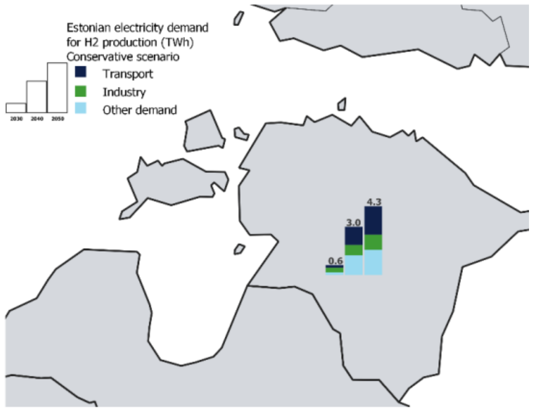
- **Transport** is the sector that represents a big challenge for the Estonian government, as it is projected to be one of the most difficult for emissions to be reduced. However, the road map indicates that green hydrogen can be used to support decarbonization across a range of transport applications, with heavy goods vehicles and other long-distance vehicles showing the greatest potential. The NECP also included a value for hydrogen use in the transport sector, but it is far more conservative, reaching just 0.05 TWh/year.

- The **Industry** sector has the greatest potential for production of green chemical products based on hydrogen. As ammonia urea, and methanol are imported, there is a drive to increase independence and manufacture these products with local renewable energy. One big advantage is that there is already infrastructure for ammonia and urea production, but it is not used. A dedicated generation of 2.2 to 4.7 TWh is projected in 2050.

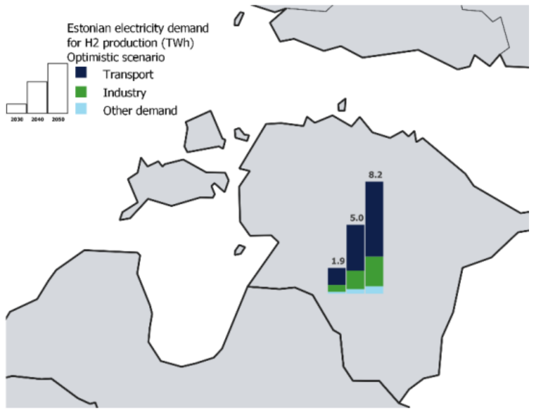
- **Buildings & power:** The model assumes that decentralized heat demand can be met by installing fuel cell micro-CHP plants that use hydrogen gas as fuel and additionally produce electricity that can be used to cover the base load of buildings.

Distribution of projected hydrogen demand per region and sector in 2030, 2040 and 2050

Conservative



Optimistic



Source: DNV

2.2 Latvia electricity surplus analysis 2030-2050

The share of each energy source in Latvia has remained relatively constant since 2000 with a slow increase of biofuels and waste for heating. Wind and solar do not provide a major contribution as the power sector has relied on hydropower, natural gas and imports. Oil plays a major role for transportation.

Latvian energy system

Renewable energy provided 45% of the total energy supply in Latvia in 2021, while the remaining share was covered by oil, natural gas and coal. Oil consumption and derivatives use has kept constant over time, without major transformations in the last two decades, as most of its use goes into the transport sector. Coal has decreased consistently over time, and now represents a very small share of consumption. Natural gas for electricity and heat generation also plays a role. Thus, Latvia's energy market was severely affected when prices skyrocketed after Russia’s invasion of Ukraine.

Hydropower plants represent the main source for electricity generation, providing between 35% and 65% of the annual electricity supply, depending mainly on hydrological seasonality. The remaining part is covered by natural gas and imports. Wood and derivatives are also major energy sources. The wood industry represented 23% of final consumption in 2021. Its use is remarkably high in the household sector, where heating is the main final use. Finally, a steady increase of biofuels and waste for heating is also noticeable.

Renewable energy plans

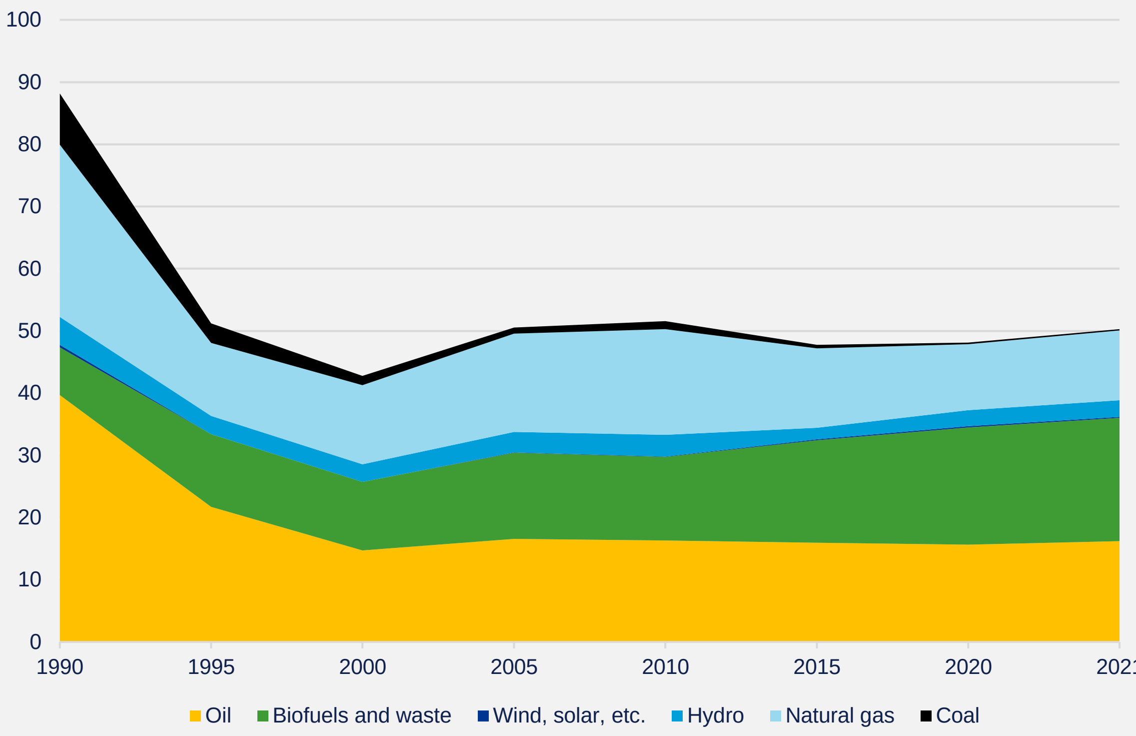
The NECP includes an indicative objective of final energy consumption from renewable energies of 50%, with an indicative share of 60% for the electricity sector. There are no secondary studies that foresee the development of the power sector consistent with these indicative targets. However, the NECP highlights Latvia’s geographical location in the Baltics, as it is the country that could develop a total installed capacity of 15.5 GW offshore wind, representing an annual energy production of 49.2 TWh.

In the renewable sector, projects with a total capacity of approximately 3.5 GW have applied for land-based transmission network connection permits, but the distribution grid faces bottlenecks to incorporate all the planned generation. In the mid term there seems to be more focus on synchronization projects with the objective of integrating the Baltic electricity transmission system to Europe, meaning that the Baltic countries will not depend any longer on Russian connections.

Hydrogen development

There is no Latvian strategic plan for the development of the hydrogen industry in the coming years. However, in December 2022 stakeholders from the industry signed a memorandum of understanding to develop a hydrogen strategy, which would be released by the end of 2023 and set a pathway for the development of hydrogen in the country. Within the policy targets, the Latvian NECP includes an indicative objective of 7% share of energy produced from RES in gross final energy consumption, which could be achieved with biofuels or hydrogen.

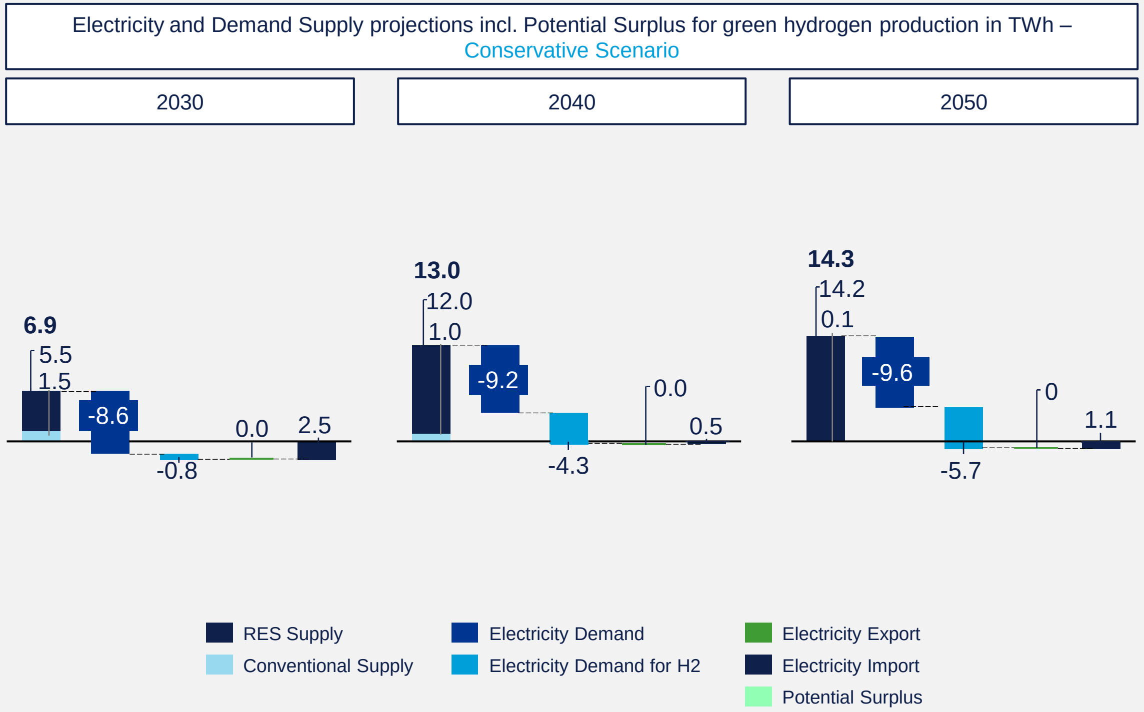
Total energy supply (TES) by source in Latvia, 1990-2021 (TWh)



Source: IEA (2022)

2.2 Latvia electricity surplus analysis 2030-2050

In a **conservative scenario** a slow development of the electricity sector would lead to a reliance on imports to cover national demands and therefore no available surplus.



Source: DNV

Electricity supply

Latvia's electricity supply, as outlined in the Global Ambition scenario from TYNDP, illustrates a significant emphasis on renewable energy sources. By 2030, the country aims to generate 5.5 TWh/year from renewables, with a vision to reach 14.2 TWh/year by 2050. Notably, offshore wind generation remains relatively constant at around 0.8 TWh/year throughout this period.

Demand

In the TYNDP Global Ambition scenario, Latvia's hydrogen demand steadily rises, jumping from 0.83 TWh/Year in 2030 to 5.71TWh/year in 2050. Hydrogen finds prominent use in the industry and transport sector. Electricity demand grows at a slower and steady pace. Grow in the electricity demand is driven by the transport sector, as it is the one that increases consistently along the scenario.

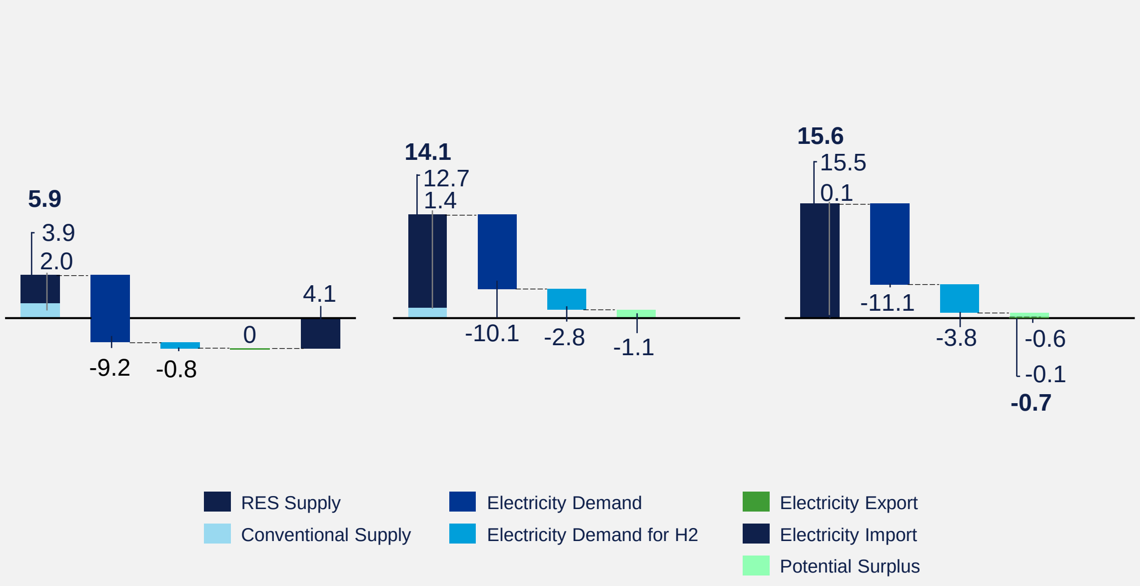
Conclusions

1. Without a remarkable development of the offshore wind sector, in this scenario the national demand needs to be covered with imports.
2. Therefore, in this scenario, during the studied period, there is no available surplus to produce hydrogen for export.

2.2 Latvia electricity surplus analysis 2030-2050

In an **optimistic scenario** with a roll out of energy supply from renewable resources, mainly offshore wind, the Latvian energy sector would be able to cover its national demand and have a slight surplus available by 2040.

Electricity and Demand Supply projections incl. Potential Surplus for green hydrogen production in TWh – Optimistic Scenario



Source: DNV

Electricity supply

Latvia's electricity supply for the **optimistic scenario** is aligned with the Distributed Energy scenario from TYNDP. The roll out of renewable energy is highly remarkable between 2030 and 2040, mainly driven by offshore and onshore wind. By 2050, the country generates all its electricity from renewable resources.

Demand

Electricity demand aligns with the trends of the Global Ambition scenario. However, the final consumption of electricity and hydrogen is higher.

Conclusions

1. In this scenario renewable resources provide 90% of electricity supply by 2040.
2. Because of a faster-developing energy supply system, in this scenario there is an available surplus in 2040 and 2050 for the production of hydrogen for export.

On the following slide we explain in more detail how the local hydrogen demand for Latvia has been derived.

2.2 Latvia electricity surplus analysis 2030-2050

Further detail on projections for Latvia’s green hydrogen demand: Latvia’s hydrogen demand is expected to replace oil usage in transportation, as it is the highest-polluting sector in the Latvian energy system.

Current demand

A pilot project to foster and study the development of hydrogen consumption and demand for public transportation was started in 2018. The “H2Nodes project” was an initiative where three European cities: Riga (LV), Arnhem (NL) and Pärnu (EE) deploy infrastructure for transport running on hydrogen. Riga as associate partner was successful in deploying hydrogen production units (300 kg/H2/day) using on-site hydrogen production via steam methane reforming of natural gas and with a maximum capacity that allows the refueling of up to 10 trolleybuses, 15 fuel cell electric buses and 5 passenger vehicles.

No clarity of hydrogen roll-out

There is no clarity nor objectives from the Latvian government towards the development of a hydrogen industry in the country. Within private efforts, the Latvia Hydrogen Association, created in 2005 to help the development of hydrogen in Latvia, is taking part in the three projects. All of them aim at fostering networking along key stakeholders of the hydrogen value chain, but none has estimated final demand for hydrogen:

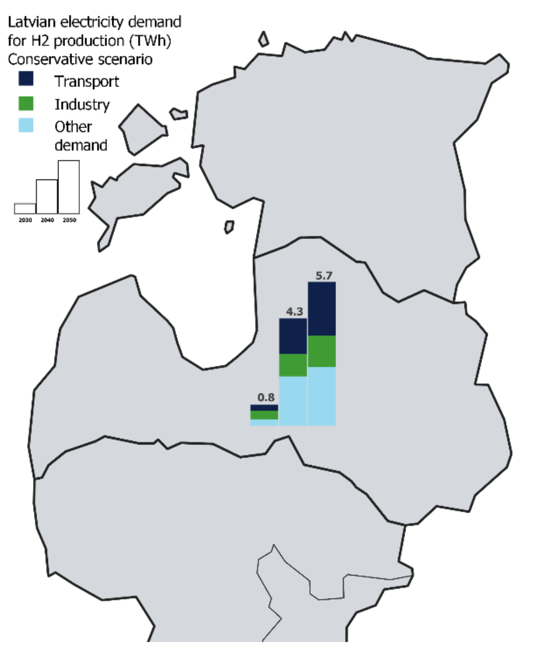
- Baltic Sea Region Hydrogen Network. A partnership among 8 hydrogen associations from different countries looking to discuss opportunities and ways to promote the development of renewable energies and hydrogen use.
- Circular economy in waste management in Riga and Tartua (Cerita), with the objective of analyzing waste composition, energy consumption and solutions, including the use of hydrogen and its derivatives.
- Preparing airports in the Baltic sea region for green hydrogen use in air transport. Here around 25 stakeholders of the flight industry are promoting the early deployment of hydrogen powered aircraft in the Baltic Sea Region.

Expected demand according to TYNDP scenarios

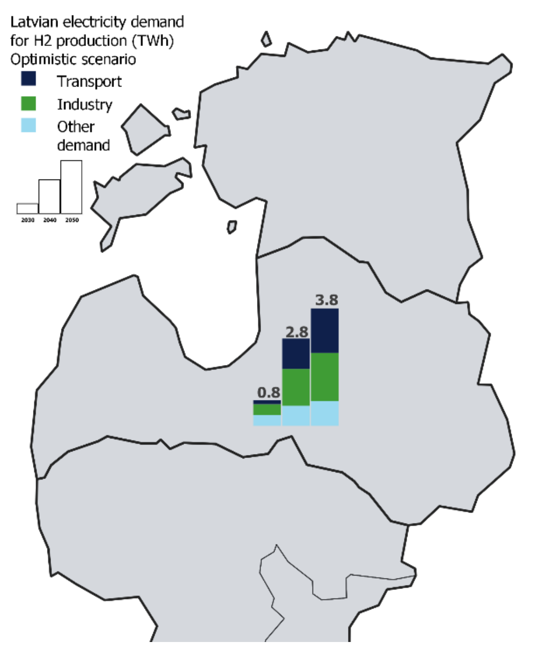
Nevertheless, the TYNDP scenarios show a roll-out of hydrogen demand for 2030, 2040 and 2050. The main use would be in the transport sector, and the major differences between Distributed Energy (DE) and Global Ambitions (GA) scenarios are in this sector: in DE final consumption is 2.14 TWh/year, in contrast to the 1.45 TWh/year achieved in GA. The second major energy sector in the development of the hydrogen demand is industry. In both scenarios the demand starts at 0.3 TWh/year and its development is quite similar; with final consumption in 2050 of 1.57 (DE) vs 1.24 TWh/year (GA). The remaining demand is seen in the residential and tertiary sector.

Distribution of projected hydrogen demand per region and sector in 2030, 2040 and 2050

Conservative



Optimistic



Source: DNV

2.2 Lithuania electricity surplus analysis 2030-2050

Since gaining independence from the Soviet Union, Lithuania's energy system has undergone a significant transformation. Since the 1990s, energy consumption has decreased, whilst reliance on oil and imports of natural gas and electricity remains high. On the other hand, the role of bioenergy and waste has increased whilst initiatives have been launched to promote hydrogen technology development and application.

Historic development of Lithuania's energy system

- Lithuania, like many other former Soviet republics, went through a period of economic transition in the early 1990s as it gained independence from the Soviet Union. This transition included shifts in industrial and economic activities, which affected energy consumption and production. Lithuania shut down or modernized some of its inefficient and outdated Soviet-era industrial facilities during this period. These facilities were energy-intensive, and their closure/modernization contributed to a reduction in energy consumption.
- Next to the reduction in energy consumption, Lithuania underwent a significant energy transformation, including the phase-out of nuclear energy after the closure of the Ignalina nuclear power plant. This led to increased reliance on natural gas and electricity imports. Lithuania's energy system historically depended heavily on imports, with domestic production covering only a quarter of total energy supply in 2019.
- Notably, Lithuania's current energy mix comprises two-thirds oil and natural gas and one-quarter renewables, primarily bioenergy and waste. The latter two have continued to grow since the 1990s, contributing to the country's energy supply diversification and decarbonization.

Role of renewables

- Renewables play a central role in Lithuania's pursuit of energy independence and decarbonization, with the share of renewables in primary energy supply increasing from about 2% in 1990 to 28% in 2021.
- Lithuania aims to achieve 100% renewable electricity by 2050, supported by new schemes and funding to boost renewable deployment and energy efficiency.

Hydrogen development

As of now, there are no specific targets set within the Lithuanian National Energy and Climate Plan (NECP) regarding hydrogen production, demand, or electrolyser capacity. However, there are Lithuanian government initiatives related to hydrogen primarily centring around a) an increase of RES in final energy consumption in the transport sector, stimulated by the Law on Alternative Fuels, which was passed in 2021, and b) the establishment of the Lithuanian Hydrogen Platform (Lithuanian H2 Platform).

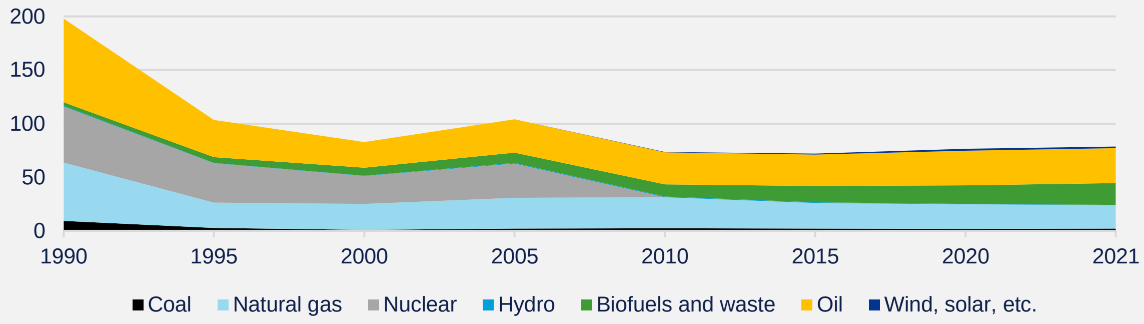
Law on Alternative Fuels

The general objective of the Law on Alternative Fuels is to increase the share of renewable energy in final energy consumption of the transport sector, which is currently at a low level (about 4% in 2019). Means to achieve an increase comprise mainly of: 1) an increase of public electric vehicle charging points (6,000 charging points by 2030), and 2) An increased use of renewable fuels such as biomethane and hydrogen gas predominantly in freight transport (at least 5% share in final energy consumption by 2030).

Lithuanian Hydrogen Platform

The Lithuanian Hydrogen Platform represents a collaborative effort comprising the Ministry of Energy and 19 organizations, including various government ministries, energy companies, and business associations. Its primary objective is to actively promote the development and integration of hydrogen technologies within Lithuania. These efforts are aimed at not only bolstering Lithuania's national energy goals but also aligning with broader European energy and climate targets. As of the present moment, detailed information regarding the progress and activities of the Lithuanian Hydrogen Platform remains somewhat limited. Comprehensive documentation, such as project updates and relevant reports, has not yet been made publicly available.

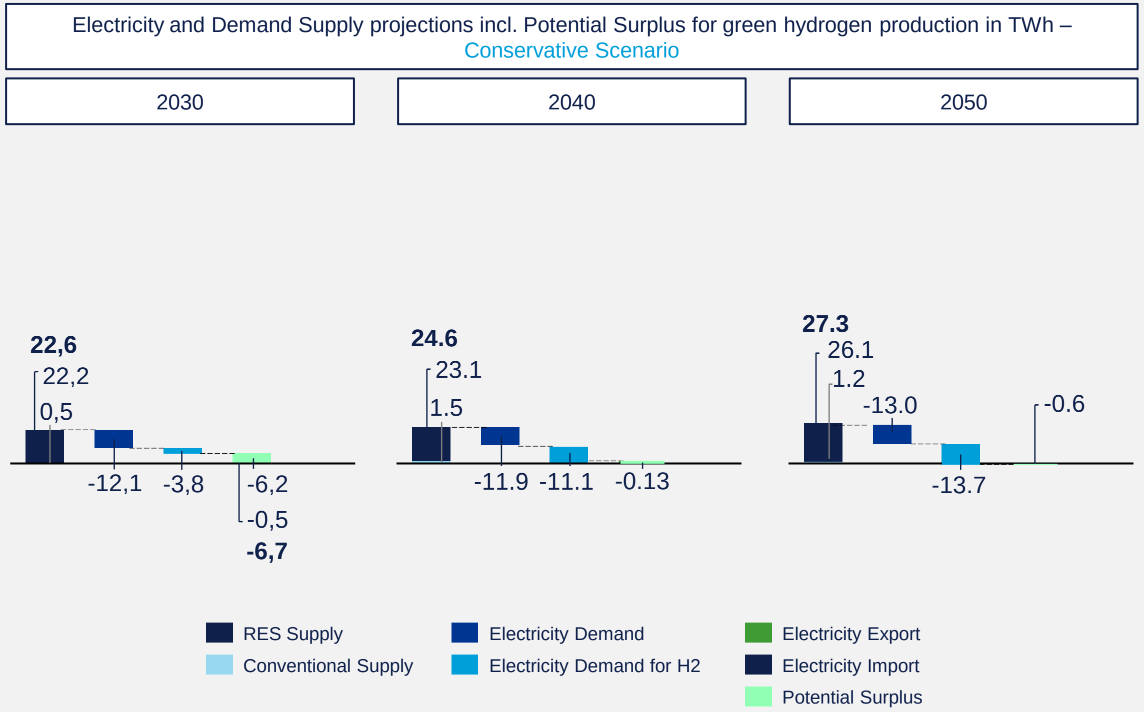
Total energy supply (TES) by source in Lithuania, 1990-2021 (TWh)



Source: IEA (2022)

2.2 Lithuania electricity surplus analysis 2030-2050

In the **conservative scenario**, Lithuania's energy future shifts towards renewables, particularly offshore wind, with a goal of 100% RES in the electricity sector by 2030. The electricity surplus available for green hydrogen export may decrease due to ambitious renewable targets for the domestic sectors and an increasing local demand.



Source: DNV

Strong renewable supply
According to the TYNDP22 Global Ambition scenario, offshore wind will experience early dispatch starting in 2030, and remaining constant until 2050. This will serve as a cornerstone in meeting future energy demand. The supply of onshore wind energy is expected to see a gradual increase over the projected timeframe. Complementing wind energy, both solar and hydro power will form integral components of Lithuania's energy mix.
According to the TYNDP 22 Global Ambition scenario, conventional energy supply only has a minor role from 2030 onwards.

Projected demand in Lithuania
The driving force behind hydrogen demand is primarily the industrial sector, expected to fuel the push towards a hydrogen economy. By 2050, hydrogen demand in the transport sector will also increase to a significant level, owing to broader application of hydrogen fuel cells.
Electricity demand is projected to remain stable across most sectors, with the only significant increase being in the transport sector due to widespread electrification. The commercial sector, on the other hand, is expected to see a decrease in electricity demand by approximately 15%.

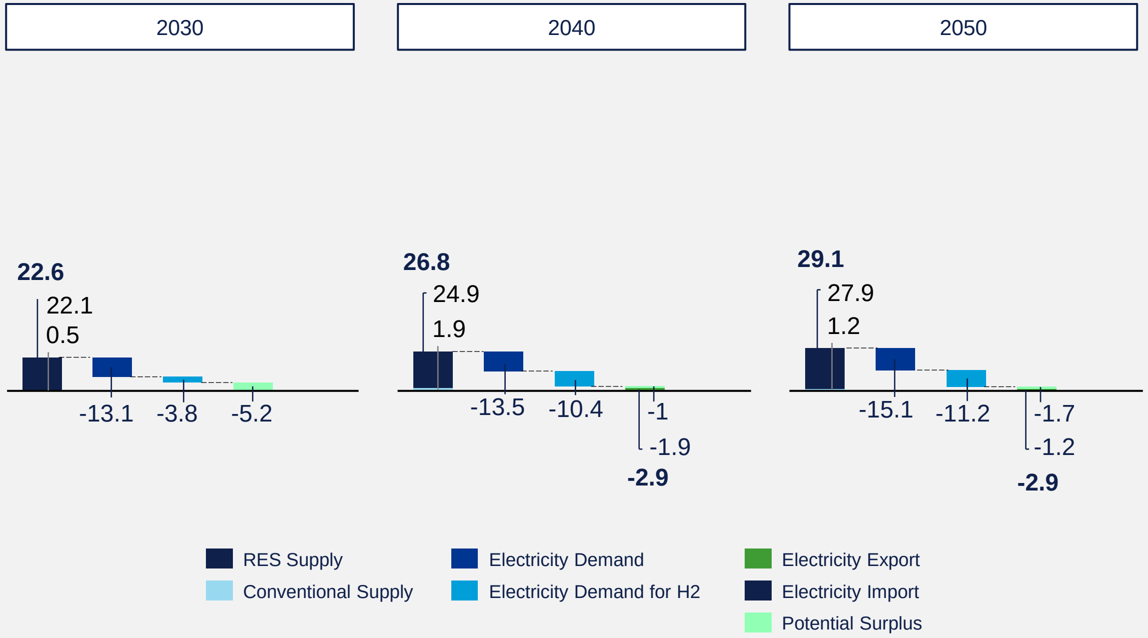
Renewable targets
According to the latest NECP, there is an ambitious target of achieving a 100% Renewable Energy Share (RES) in electricity production from 2030 onwards. This goal is naturally carried forward also beyond 2050.

Potential surplus
The underlying scenario suggests that the potential surplus will decrease over time. As a result, no significant real surplus can be expected as an input to the production of green hydrogen for export. This contraction in surplus is due to Lithuania's ambitious RES targets for its national sectors as well as local increases in demand.

2.2 Lithuania electricity surplus analysis 2030-2050

In the **optimistic scenario**, Lithuania undergoes a stronger shift to renewables compared to the previous scenario. Electricity demand remains steady, except for transport, which is electrifying. Industry drives domestic hydrogen demand, with growth expected in the transport sector whilst an electricity surplus for green hydrogen export may decline due to local demand and decarbonization goals.

Electricity and Demand Supply projections incl. Potential Surplus for green hydrogen production in GWh – Optimistic Scenario



Source: DNV

Projected electricity supply and demand in Lithuania
Lithuania's energy landscape is set for a transformative shift, as outlined in TYNDP22's Distributed Energy scenario. Anticipating early offshore wind deployment by 2030, complemented by gradual onshore wind expansion, along with solar and hydro power integration, Lithuania reduces reliance on conventional energy sources, aiming to phase them out completely by 2050.
Regarding electricity demand, conventional consumption remains constant, with the only notable rise occurring in the transport sector due to electrification. Conversely, the commercial sector anticipates a reduction in electricity demand of approximately 15%.

Domestic hydrogen demand is primarily driven by industry
The demand for hydrogen is primarily being propelled by the industrial sector and is expected to witness substantial growth. Industry is the driving force for domestic demand in 2030 (86% of total H2 demand) up until 2050 (78%) whilst hydrogen demand in the transport sector develops a significant share by 2050 (15%).

Potential surplus
Lithuania's ambitious energy targets, as outlined in the latest National Energy and Climate Plan (NECP), include achieving a 100% renewable energy share in electricity production from 2030 onwards. However, potential electricity surplus for the production of green hydrogen for export is projected to dwindle over time, largely attributed to increasing local demand and the country's high renewable energy targets to decarbonize its national sectors.

On the following slide we explain in more detail how the local hydrogen demand for Lithuania has been derived.

2.2 Lithuania electricity surplus analysis 2030-2050

Further detail on projections for Lithuania’s green hydrogen demand: The ammonia and refining industries, concentrated in Lithuania's western region, are the primary drivers of the current hydrogen demand. Lithuania is actively pursuing hydrogen deployment, including the promotion of hydrogen-powered vehicles and the development of hydrogen infrastructure, in anticipation of significant demand growth in industrial and transportation sectors.

Current hydrogen demand

Currently, Lithuania's overall hydrogen demand is approximately 200 kilotons or equivalent to 6.7 TWh. This demand is mainly driven by two key sectors: the ammonia industry, accounting for approximately 150 kilotons or roughly 5 TWh, and the refining sector, contributing around 50 kilotons or about 1.7 TWh. These ammonia and refining activities are predominantly concentrated in the western region of Lithuania, where there is a significant EU-ETS scale ammonia plant operated by the Achema group in Jonavos and the sole Lithuanian refinery, owned by the ORLEN Lietuva group in Juodeikiai.

Projected hydrogen demand

Lithuania is currently focusing on hydrogen deployment primarily for research, development, and innovation, with no specific targets mentioned in its National Energy and Climate Action Plan. The country is compiling National Hydrogen Development Guidelines, with the Lithuanian Hydrogen Platform facilitating cooperation among research institutions, businesses, and the public sector. Lithuania has allocated significant funding, including EUR 300 million by 2030, to support hydrogen production and related projects, with plans to use surplus offshore wind electricity for green hydrogen production and potential export.

In addition to those initiatives, there have been developments aimed at outlining approaches for utilizing hydrogen in the transportation sector, which include the introduction of the "Guidelines for the Development of Hydrogen Filling Infrastructure and the Promotion of Hydrogen-Powered Road Vehicles in Lithuania”. These guidelines primarily encompass the following objectives:

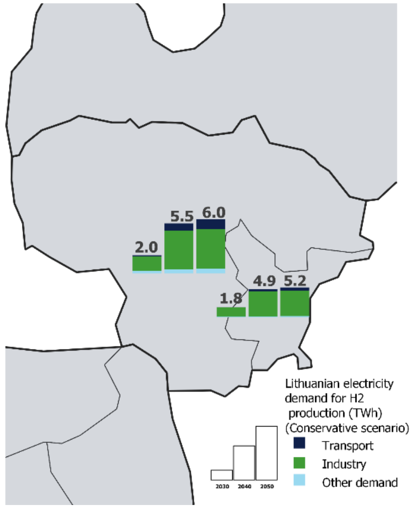
- **Objectives and measures for hydrogen refilling infrastructure development:**
  The plan involves the installation of at least four public hydrogen filling points by 2026, with the first one expected to be operational by the end of 2024. The goal is to establish a network comprising a minimum of ten hydrogen filling points (both public and private) within Lithuania by 2030.
- **Objectives and measures for promoting hydrogen-driven vehicles:**
  The promotion of hydrogen-powered vehicles will target the goal of having at least 5% of all new vehicle purchases in Lithuania powered by hydrogen by 2030. Financial incentives will be offered to encourage the acquisition of hydrogen-powered vehicles. For instance, hydrogen-powered cars will be exempt from road user tax, and tax relief measures will be provided to further incentivize their use.

TYNDP 22 projections

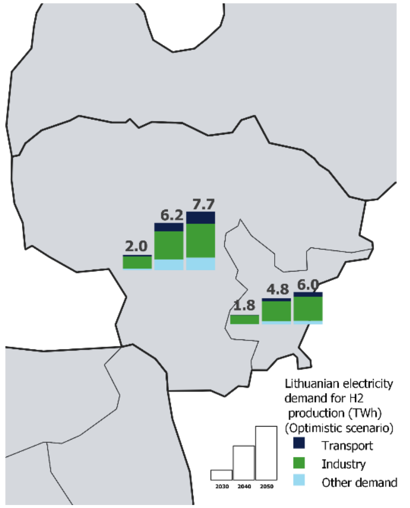
In accordance with the TYNDP 22 scenarios "Global Ambition" and "Distributed Energy," there is an anticipation of significant growth in hydrogen demand within Lithuania, particularly within the industrial and transportation sectors. This aligns with projections made by publicly accessible sources. Consequently, it is estimated that the electricity demand for hydrogen production will rise to a range of 11-14 terawatt-hours (TWh) by 2050. Within this, the industrial sector is expected to account for approximately 9 TWh, while the transportation sector is expected to contribute 2-3 TWh.

Distribution of projected hydrogen demand per region and sector in 2030, 2040 and 2050

Conservative



Optimistic



Source: DNV

2.2 Poland electricity surplus analysis 2030-2050

Poland aims to reduce GHG emissions significantly, with a shift away from coal and towards renewables, nuclear and energy efficiency, yet there is a need for alignment with the EU's more ambitious targets.

Historic development of Poland's energy system

- Poland experienced a decade of strong economic growth from 2010 to 2019 (38% increase of GDP), driving a significant increase in energy demand, particularly from the transport and industry sectors. During this period, the energy intensity of Poland's economy decreased due to improved energy efficiency and a stronger role for the service sector.
- Poland's energy supply remains heavily reliant on fossil fuels, with coal accounting for the largest share (40%) in 2020, followed by oil (28%) and natural gas (17%).

Poland's GHG emission targets

- Poland's GHG emission targets include reducing non-ETS GHG emissions by 7% by 2030 (compared to 2005 levels) and reducing GHG emissions from the entire economy by 30% by 2030 (compared to 1990 levels).
- The main elements to achieve these targets are transitioning away from coal (56-60% decreased share in electricity production by 2030) and towards renewable and low-carbon energy sources, such as gas-fired and nuclear generation as well as improved energy efficiency (23% energy efficiency improvement for primary energy consumption by 2030 compared to 2007).
- As Poland's 2030 targets outlined in the Energy Policy of Poland until 2040 (EPP2040) and NECP do not yet account for the adoption of the increased EU-wide targets for greenhouse gas emission reduction (55% reduction by 2030 and climate neutrality by 2050), adjustments will be necessary to align policies, goals, and measures with the EU objectives.

Role of renewables

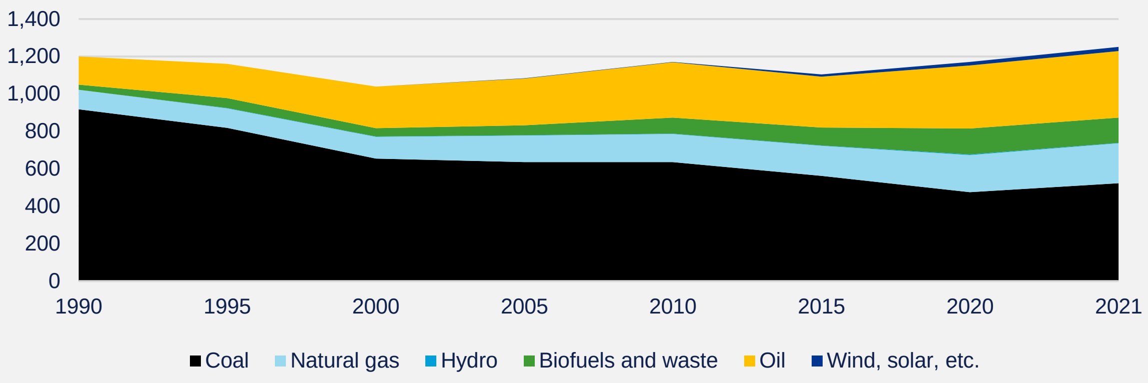
- From 2010 to 2020, Poland's share of renewable energy supply increased from 8% to 14%, driven primarily by growth in wind generation and the direct use of solid biomass for heating. Despite this progress, Poland's share of renewables remains relatively low, ranking 21st among IEA member countries in 2019 (based on Total Final Energy Consumption).
- Poland's energy policy places significant emphasis on renewable energy in various strategic areas, such as renewable electricity generation (with a focus on offshore wind and small-scale solar PV), reducing transport sector oil demand through biofuels and renewable electricity, and increased use of renewables in heating and cooling.

Future role of hydrogen in Poland's energy system

Poland's vision for hydrogen involves establishing a robust market and infrastructure to drive decarbonization efforts across its diverse economy. While currently ranking third among European hydrogen producers with an annual output of around 1 million tons (34 TWh), most of it is still produced from fossil fuels. Nevertheless, the Polish NECP and the Polish Hydrogen Strategy recognize hydrogen's significant economic potential, identifying its applications in using hydrogen for heating, electricity generation, transportation, and decarbonizing industries.

Whilst qualitative assessments about the hydrogen development are made in Poland's NECP and Hydrogen outlook, there is a **lack of officially produced data quantifying the current hydrogen demand and supply per sector**. The report "Green Hydrogen from RES in Poland," prepared by the Polish Wind Energy Association and the Silesian Institute of Energy Studies, is the first comprehensive study on green hydrogen, offering insights into the current state of the hydrogen market. Our analysis relies on this report to provide quantitative statements regarding hydrogen demand and supply today, whereas the TYNDP 22, prepared by ENTSO-E and ENTSO-G, is used to gain insights into the future development of hydrogen.

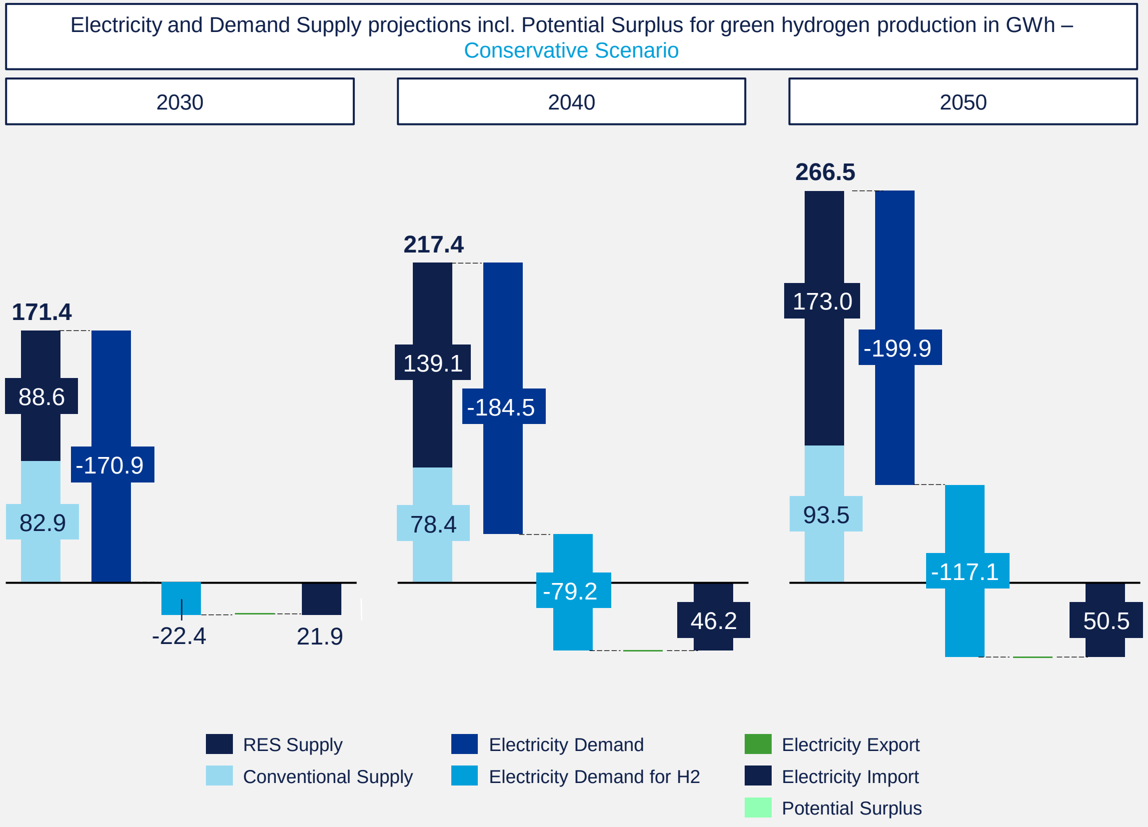
Total energy supply (TES) by source in Poland, 1990-2021 (TWh)



Source: IEA (2022)

2.2 Poland electricity surplus analysis 2030-2050

Poland's energy landscape is set for significant changes: A shift towards renewables and nuclear power generation and the phasing out of coal by 2040. In a **conservative scenario** however, a 15% increase in electricity demand by 2050, driven by the transport sector and hydrogen technologies, is outpacing electricity generation expansion, leading to a reliance on electricity imports, projected to reach 51 TWh by 2050.



Source: DNV

Electricity supply

According to the TYNDP projections, Poland is poised for a significant transformation in its energy mix, characterized by a notable increase in renewable sources. By 2030, onshore and offshore wind generation is set to reach 70 TWh, while solar generation will double to 10 TWh. Despite these advancements, coal remains the primary energy producer, contributing 50 TWh in 2030, but it is slated for phase-out by 2040.

A significant shift occurs in 2040 when nuclear power emerges as a key player, generating 30 TWh initially and doubling to 60 TWh by 2050. Poland's strategic deployment of nuclear power, beginning in 2033, aims to meet growing electricity demands, with plans for multiple nuclear power plants. Concurrently, gas generation experiences a surge, increasing from 20 TWh in 2030 to 40 TWh in 2040. However, as renewables and nuclear power generation expands further by 2050, gas generation declines to approx. 30 TWh.

Electricity demand

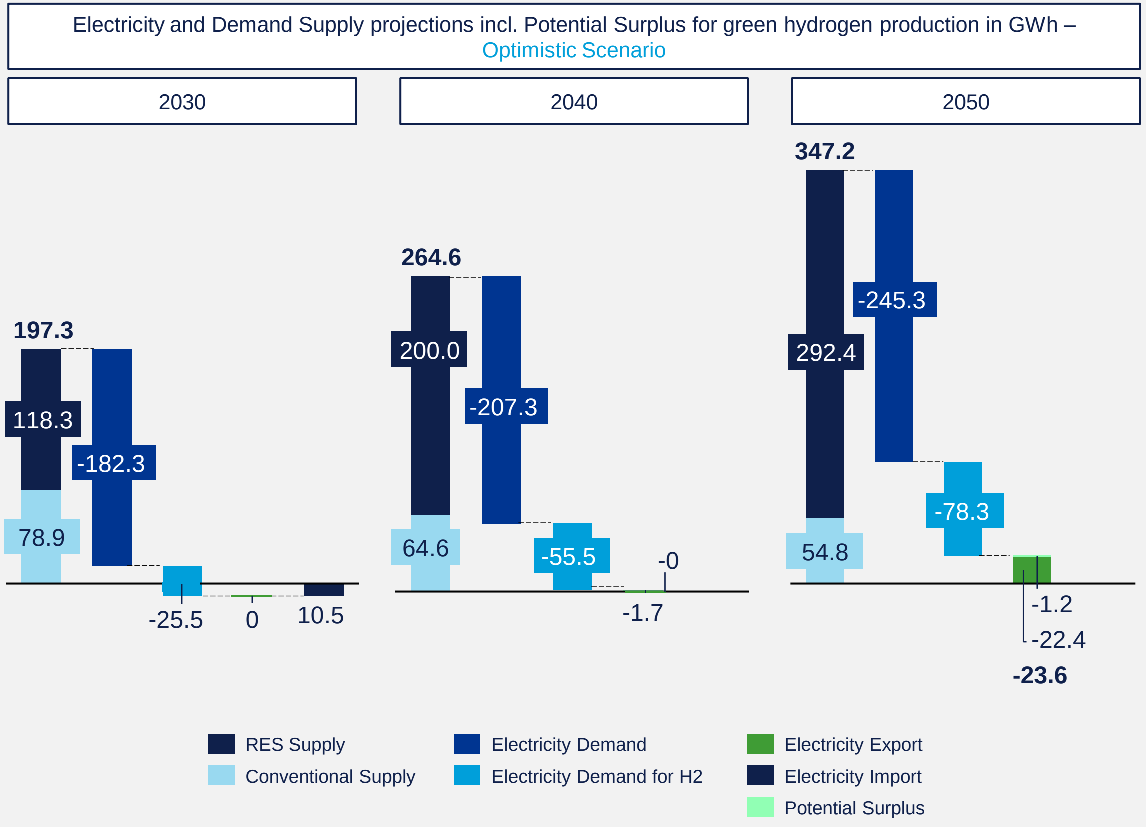
The TYNDP projections indicate a substantial increase in domestic electricity demand by 2050, with a 15% growth compared to 2030 levels (excluding electricity for hydrogen). This surge is primarily attributed to the growth in the transport sector, where electricity demand is expected to increase from 10 TWh in 2030 to 40 TWh by 2050. Moreover, the surge in domestic hydrogen demand plays a pivotal role in this evolving energy scenario. The transition to hydrogen-based technologies is set to drive a surge in electricity requirements to produce hydrogen, which is predicted to rise from approximately 20 TWh in 2030 to 120 TWh by 2050. Notably, the year 2030 is anticipated to see substantial hydrogen applications in the industrial sector, accounting for 16 TWh of electricity demand. As we progress towards 2050, the demand for hydrogen in the transport and residential sectors is expected to reach comparable levels, each around 30 TWh, while the industrial sector will continue to be the largest consumer of hydrogen-derived electricity, demanding approximately 40 TWh.

Findings

In contrast to having an electricity surplus available for hydrogen production for export, there is a growing need for electricity imports, which are projected to rise from 22 TWh in 2030 to 51 TWh in 2050.

2.2 Poland electricity surplus analysis 2030-2050

In an **optimistic scenario**, Poland is in the process of shifting towards an electricity supply heavily reliant on renewable generation, projected to reach an 84% share by 2050. Also accounting for an increased electricity demand, this could result in an overall electricity surplus by 2050, but it's important to note that this surplus would mainly consist of non-renewable electricity, rendering it unavailable for green hydrogen production.



Source: DNV

Electricity supply

The development of the Polish electricity supply is undergoing a transformative shift, primarily characterized by a significant integration of renewable energy sources. As of the TYNDP 22 scenario 'Distributed Energy', renewable electricity generation surges to constitute approximately 60% of the total electricity production by 2030 (120 TWh) and 84% by 2050 (300 TWh).

This remarkable shift is predominantly driven by the rapid expansion of wind power in the overall electricity supply. Wind generation is projected to escalate from 50% in 2030, equivalent to 100 TWh, to a substantial 70% in 2050, contributing around 250 TWh. Additionally, solar energy generation will play a crucial role, with its share projected to increase from 5% in 2030 (10 TWh) to 12% in 2050 (40 TWh).

Interestingly, this ambitious transformation does not involve the development of nuclear power generation in the scenario. Instead, the focus is squarely on harnessing the potential of renewable resources.

However, it's worth noting that this green energy revolution will not come without its challenges. By 2040, Poland is expected to have virtually no surplus of electricity, reflecting the growing demands of its energy-demanding economy. Nevertheless, by 2050, a surplus of approximately 24 TWh is anticipated, leading to the possibility of electricity export.

Electricity demand

The demand for electricity excluding hydrogen is set to rise by about 30% between 2030 and 2050, rising from 180 TWh in 2030 to 250 TWh in 2050. This is primarily due to the electrification of the transport sector, accounting for 70% of the increase, with demand expected to grow from 10 TWh in 2030 to 60 TWh in 2050.

Simultaneously, electricity demand for domestic hydrogen applications is projected to increase significantly, from 25 TWh in 2030 to around 80 TWh in 2050. The majority of hydrogen production will be used to meet industrial demand, constituting about 80% in 2030 and stabilizing at 60% in 2050, while the transport sector's share is expected to increase from less than 10% in 2030 to approximately 20% in 2050.

Findings

In this scenario, Poland's power generation is projected to increase sufficiently to meet the rising electricity demand, and it may even lead to an electricity surplus. However, it is important to note that this surplus is expected to primarily consist of grey electricity, as generated renewable power is essential to decarbonize domestic electricity demand across all sectors, including domestic hydrogen production.

On the following slide we explain in more detail how the local hydrogen demand for Poland has been derived.

2. Poland electricity surplus analysis 2030-2050

Further detail on projections for Poland’s green hydrogen demand: Poland presently holds the position of the third-largest hydrogen producer in Europe, primarily serving the ammonia production and refining sectors. In the coming years, a shift towards green hydrogen is foreseen, particularly in industrial and transportation sectors. Those sectors are estimated to contribute to a combined demand of 60-81 TWh, out of a total projected demand of 78-117 TWh by 2050.

Current hydrogen demand in Poland

Poland stands as the third-largest hydrogen producer in Europe, generating approximately 1 million tonnes (equivalent to 34 TWh) of hydrogen annually. Presently, the principal applications for this hydrogen output are in ammonia production facilities (accounting for 13 TWh) and refineries (amounting to 12 TWh).

- Refining Industry: Hydrogen is already widely used in the refining industry to remove impurities from crude oil and produce fuels such as gasoline and diesel. Orlen S.A. and Grupa Lotos are the largest producers of hydrogen for the refining industry with approximately 5 and 2 TWh hydrogen produced per year respectively. In the future, the refining industry could transition to using "green hydrogen" produced from renewable sources to reduce its carbon footprint.
- Ammonia Production: Currently, ammonia production relies heavily on hydrogen derived from natural gas. However, in the future, "green ammonia" could be produced using hydrogen from renewable sources, making the current ammonia production process more environmentally friendly.

Projected hydrogen demand in industry

Hydrogen has the potential to play a significant role in Poland’s industrial sectors in the future. It can offer a clean and sustainable energy source e.g., for the refining and steel industry and for the production of hydrogen derivatives such as ammonia. Based on TYNDP 22 scenarios 'Global Ambition' and 'Distributed Energy,' it is projected that industrial hydrogen demand will increase to 27-38 TWh in 2040 and reach approximately 41-49 TWh by 2050.

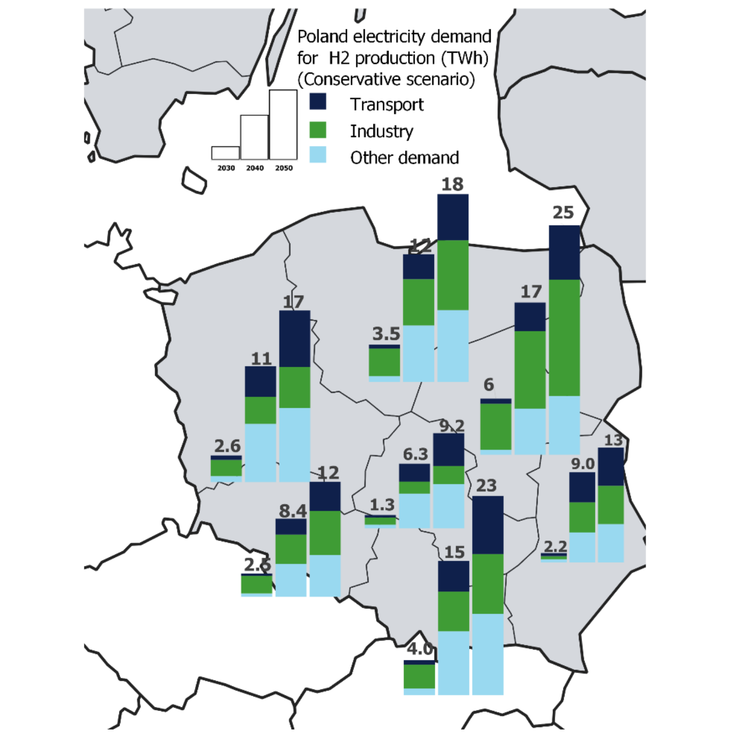
Future hydrogen demand in transport

According to Poland’s Hydrogen Strategy, the demand for hydrogen in the transport sector in Poland is expected to grow significantly over the period of 2020-2030. Until 2025, the estimated demand will be approximately 2,933 tonnes (~0.03 TWh), with a major portion of 1,764 tonnes (0.02 TWh) needed for refuelling zero-emission buses. To meet this demand, 32 new hydrogen refuelling stations operating at pressures of 350 and 700 bar will be constructed.

Looking ahead up to 2030, the demand for hydrogen in the transport sector is projected to increase to 22,510 tonnes per year (0.21 TWh). This growth will be supported by various initiatives, including the operation of hydrogen-powered zero-emission buses, expansion of the hydrogen refuelling and bunkering infrastructure, development of hydrogen trains and locomotives, and the introduction of hydrogen-based propulsion systems for vessels. Additionally, research and pilot programs will be conducted to explore the potential use of hydrogen and its derivatives in various modes of transport, including urban transport, heavy-vehicle, rail, sea, river, air, and intermodal transport. The production of synthetic fuels based on hydrogen will also be explored as a potential alternative in the transport sector.

In line with TYNDP 22 scenarios 'Global Ambition' and 'Distributed Energy', there is a notable surge in hydrogen demand within the Polish transportation sector after 2030, reaching 10-17 TWh by 2040. Moreover, a continued upward trend is anticipated, with expectations of it growing to 19-32 TWh by 2050.

Distribution of projected hydrogen demand per region and sector in 2030, 2040 and 2050 in the conservative scenario

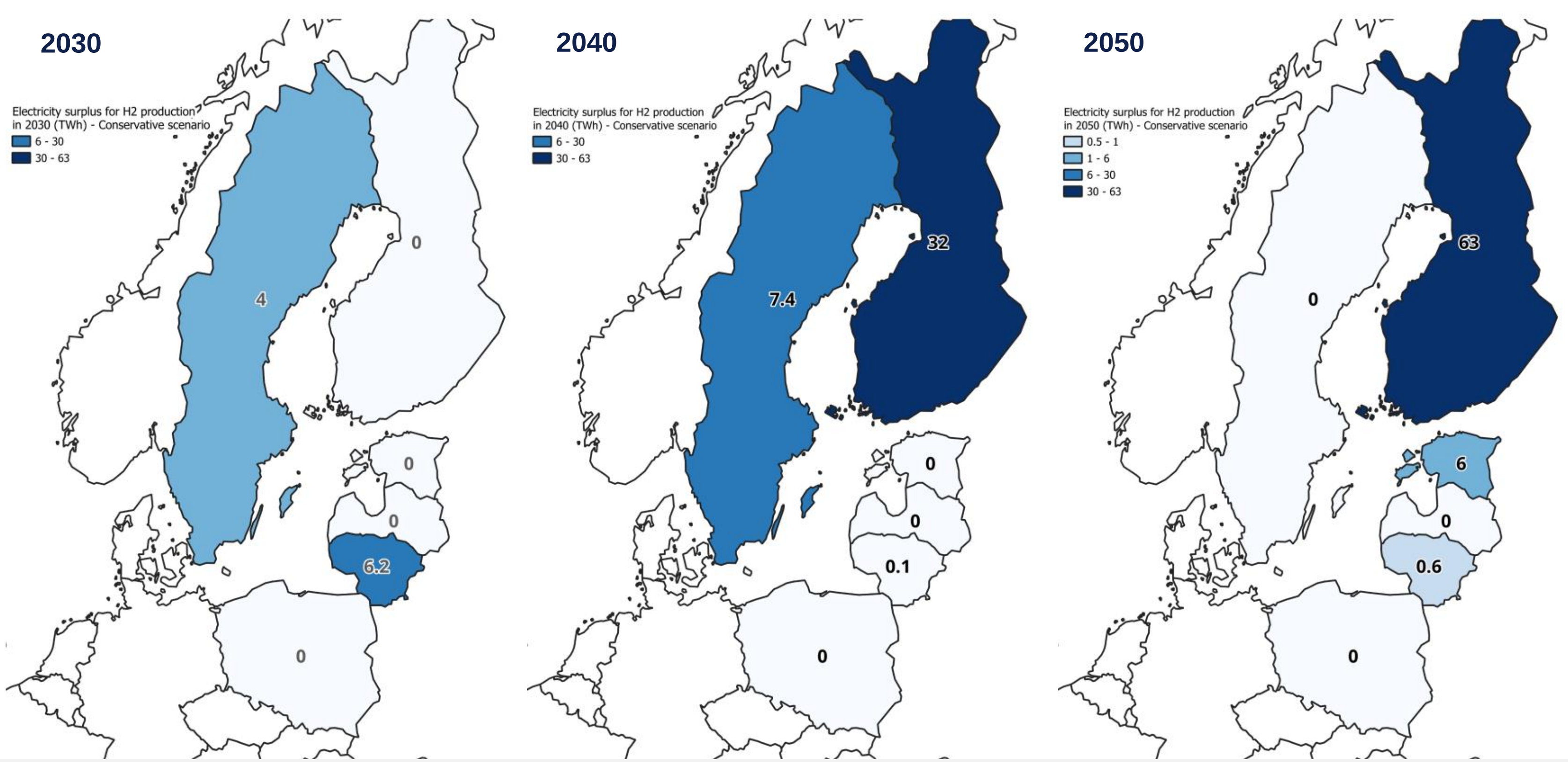


Source: DNV

2.3 Summary – Baltic area hydrogen production potential

The surplus potential in the Nordic countries changes its pattern under the **conservative scenario**. Whilst Sweden offers surplus potential in 2030 this potential is reduced to almost zero by 2040, whilst Finland shows a significant surplus. In total around 70 TWh_{el} are available in 2050.

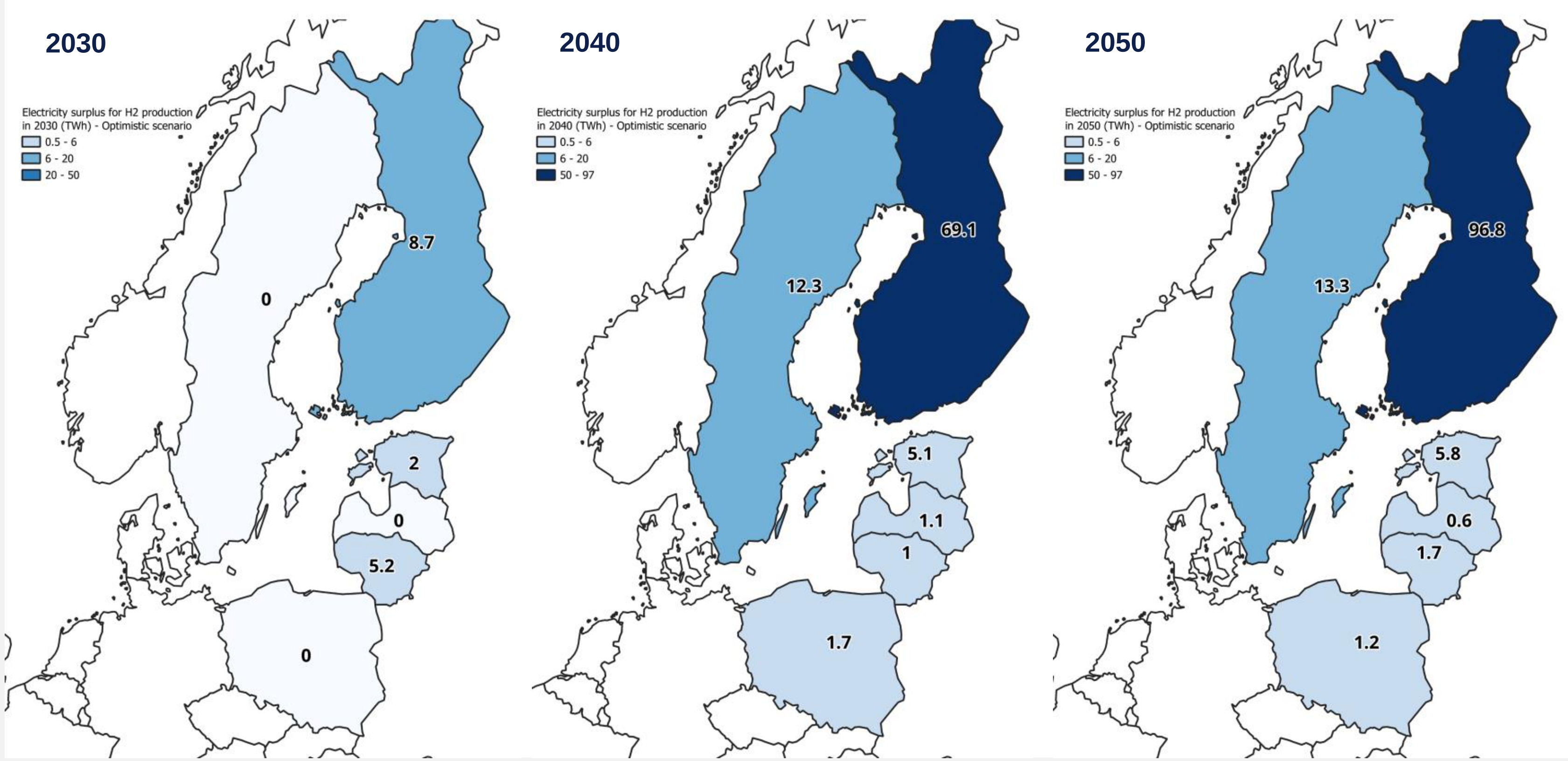
- As we have shown in this chapter, the hydrogen production potential depends very much on the decarbonisation pathways that are adopted in the individual countries. In the **conservative scenario**, we see that Finland in particular can achieve a significant electricity surplus in 2050, which could be used to produce green hydrogen for export. But Sweden's electricity surplus will fall continuously over the chosen period, with no surplus in 2050.
- In total we find a potential under the conservative scenario of about 70 TWh_{el} in 2050 that can be sourced from the region in 2050 with Finland providing the main source of surplus.
- Overall, the surplus shown is relatively small, particularly given that Sweden has little or no surplus due to industry electrification and domestic hydrogen use.
- The surplus is likely to originate from onshore and offshore wind. Onshore wind electricity can be expected to be the main source of surplus, with a share of about 40-50% (SE) and 70-80% (FI) of RES electricity generation in 2030-2050. This is followed by offshore wind with a share of RES generation increasing to 10-20% in 2050 (SE), and some 5% in 2030 and 11% in 2050 (FI).



2.3 Summary – Baltic area hydrogen production potential

Under the **optimistic scenario** there is a bigger surplus potential of about 119 TWh_{el} expected. Finland is the main contributor here, as in the conservative scenario. The overall regional pattern in this scenario shows a higher stability than the conservative scenario.

- In the **optimistic scenario** we see a more balanced development across the area. Still Sweden is starting with the highest surplus potential in 2030 which then halves by 2040 but afterwards remains stable. Whilst for Finland we observe an even stronger increase then in the conservative scenario. Timewise the following overall potential for surplus electricity to be used to produce green hydrogen for export could be achieved:
  - 2030: 16 TWh_{el}
  - 2040: 90 TWh_{el}
  - 2050: 119 TWh_{el}
- Also in this scenario Finland remains the largest contributor and would produce about 30 TWh_{el} more than in the conservative scenario, which could be used for hydrogen production for export.
- Additionally, there is a small potential from the Baltic states and Poland.
- The precise NUTS regional breakdown for both scenarios will be explained in chapter 4 when we will address potential pipeline routings



2.3 Summary – Baltic area hydrogen production potential

The scenarios show that the hydrogen potential in the Baltic area – based on the current energy plans of the related countries – is significantly lower than the North Sea. In the next chapter we will address the economics of hydrogen production in the region at scale.

- As the scenarios show, there is a potential in the Nordics for hydrogen production for export. Depending on the scenario, in 2050 this ranges from 70 to 109 TWh_{el}. The latter would equate to approximately 70 TWh of hydrogen. Compared to the potential that can be found in the North Sea this is significantly lower – looking at current plans.
- The analysis nevertheless illustrates how dependent this production potential is on the national energy plans in the respective countries. For Sweden and Finland, we consider the potential could even be higher if there were more ambitious plans to produce electricity for the purpose of exporting hydrogen. These plans nevertheless are non-existent or are at an immature state at the moment. Especially for Sweden the surplus remains rather low compared to the size of the country. If Sweden could be developed into a strategic hydrogen sourcing partner for Central Europe, the patterns shown above could change.
- On the other hand, and as stated in the introduction to this study, the assumption that the electricity surplus is entirely used for hydrogen production neglects the parallel electrification in Central Europe, and the likely demand for electricity imports. Part of the electricity generation surplus in Finland and Sweden may therefore also be used to export electricity directly, without converting it into hydrogen.
- Before we address a potential pipeline routing and dimensioning in chapter 4, that describes how this hydrogen potential might be transported to Central Europe, we will in chapter 3 take a closer look at the hydrogen production economics that come with the wind resources in the different geographies in the north.
- This aspect is very relevant to a potential case to make use of hydrogen produced in the north and therefore also to the question of whether the Baltic countries should take a joint action for an even higher ambition for renewable energy, in order to build a significant hydrogen production in the region for export through hydrogen pipeline connections.

Source: DNV

3.1 Introduction: Renewable hydrogen production by wind energy

This chapter provides an analysis of the potential cost at which hydrogen can be produced in the Baltic area by means of mainly wind energy (off- and onshore). Wind resources in the Baltic area have a significant spread. This affects the LCOH that can be achieved quite significantly.

In this chapter we take a closer look at the hydrogen production cost that can be achieved in the Baltic countries under focus in this study. For this purpose, we will analyse in the first place the wind resources in the area – due to the high latitude of the region, wind is the preferable resource to use for the production of hydrogen, rather than PV.

The analysis of wind resources will follow the same pattern as in the previous chapter and again the NUTS 2 regions will be used in order to obtain a good view on the capacity factors and levelized cost of electricity (LCOE) that can be obtained in the different regions.

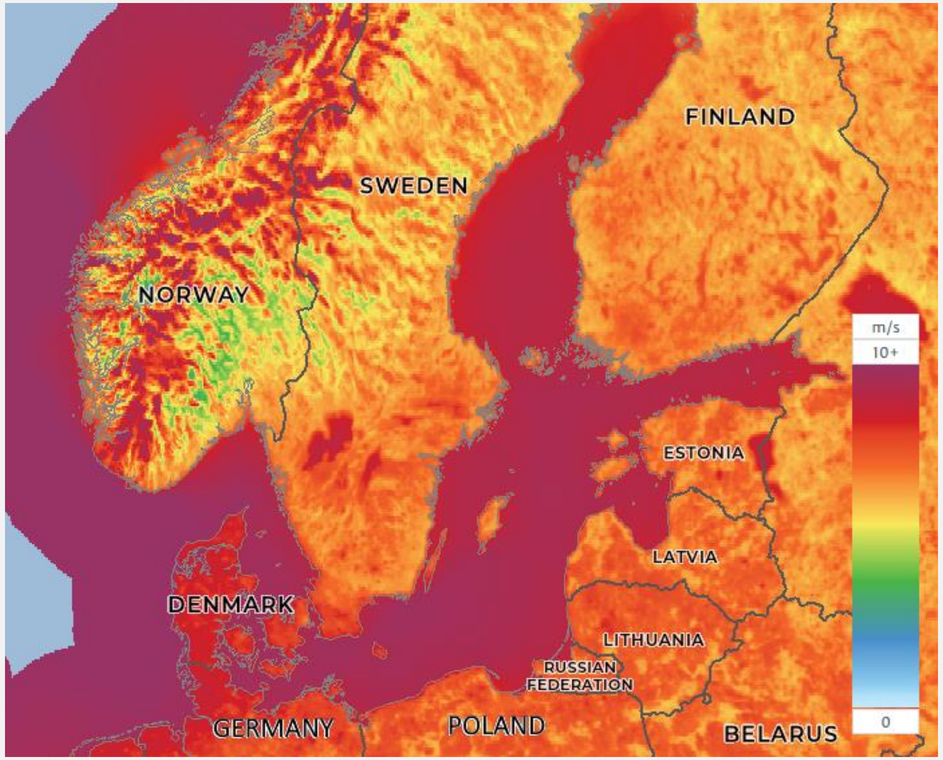
Based on these data, our second step will be to conduct a levelised cost of hydrogen calculation for the various regions. This will be conducted for onshore wind – and for offshore wind for those regions that have their own coastline. For offshore wind, we show in this context whether offshore or onshore electrolysis is more economical and which connection system (HVAC, HVDC or pipeline) has the lowest specific costs.

The data of this chapter, together with the data of the first chapter, then result in an analysis at NUTS 2 level, through which capacities and costs are transferred into routing options.

Main rationale of the analysis:

- In order to justify an export of hydrogen the production of this energy vector needs to be cost efficient compared to other sourcing options. In this regard the levelized cost of hydrogen (LCOH) is the commonly used key performance indicator. As renewable resources are not spread homogenously due to differences in the geomorphology of countries these LCOHs vary. For the purpose of this study, we have therefore carried out an LCOH assessment that follows the same regionalization assessment as the surplus analysis.
- For Northern Europe Wind is the prevailing resource that can be utilized for the production of green hydrogen. Due to the relatively low irradiation and the low full load hours in higher latitude areas, PV is less well suited. Nevertheless, wind is also not a homogeneous resource.
- The graph on the right-hand side – taken from the global wind atlas (**Global Wind Atlas**) shows the general pattern of how wind resources are spread on average in North Europe for a hub height of 50 meters. It shows that generally the sea areas have higher wind speeds measured in meters per second than the land areas and it also shows that the North Sea has on average higher wind speeds than the Baltic Sea.
- When comparing e.g. onshore wind in Northern Germany with e.g. mid Sweden it also becomes apparent that there is more wind in Northern Germany. Thus, in order to assess the LCOH in the Baltic Sea area a differentiated analysis of the wind resources available is needed.
- These mentioned patterns will be analysed in this chapter in detail.

Mean wind speed at a height of 100m



Source: Global Wind Atlas

3.1 Introduction: Renewable hydrogen production by wind energy

This chapter provides an analysis of the potential cost at which hydrogen can be produced in the Baltic area by means of mainly wind energy (off- and onshore). Wind resources in the Baltic area have a significant spread. This affects the LCOH that can be achieved quite significantly.

- The levelized cost of hydrogen (LCOH) calculation **in this chapter is for the main part based on an electrolyser with co-located renewable resources**. At the end of the chapter, we will also describe a different approach, where the electricity is taken from the power grid - which is possible under certain circumstances described below. For this we will check whether the renewable feed in the investigated areas is above 90%, as is required to quality for an exemption to the RED II criteria on items such as renewable PPAs, additionality and temporal matching. For these cases we have then taken DNVs long term electricity price forecast into account.

- We take this additional perspective as the business models for electrolysers (regarding LCOH) differ and are also subject to European regulation that influences significantly the applicability of a business model in a respective geographical area.

RED II RFNBO rules

The RED II rules for counting electricity taken from the grid as fully renewable can be found in the relevant Delegated Acts (see https://energy.ec.europa.eu/publications/delegated-regulation-union-methodology-rfnbos_en), and are as follows:

- **High renewables ratio in bidding zone:** If the electrolyser is located in a bidding zone where the renewable electricity share exceeds 90% over the previous calendar year, the hydrogen automatically counts as fully renewable, but the maximum amount of full-load hours is capped at the same percentage.
- **Low emissions in bidding zone:** If the electrolyser is located in a bidding zone with emissions of less than 18 gCO2e/MJ, it must meet the geographical and temporal requirements set out below, but not the additionality requirements.
- **Alternative approach:** If the bidding zone has <90% renewable electricity share and emissions greater than 18 gCO2e/MJ, three conditions must be met – namely **1) a**dditionality **2)** temporal correlation and **3)** geographical correlation.

  1. **Additionality:** Electricity taken from the grid may be counted as fully renewable provided that it is produced exclusively from renewable sources and the renewable properties and other appropriate criteria have been demonstrated by the conclusion of a power purchasing agreement, ensuring that the renewable properties of that electricity are claimed only once and only in one end-use sector. The installation generating renewable electricity must have come into operation not earlier than 36 months before the RFNBO production facility. If the RFNBO production facility came into operation before 1 January 2028, then the additionality requirement is waived until 1 January 2038.
  2. **Temporal correlation:** The balance between the renewable electricity purchased through one or several PPAs and the amount of electricity taken from the grid to produce the fuel shall be achieved on a monthly basis in order for the production to be fully qualified as renewable fuel of nonbiological origin. **From 1 January 2030**, this balance shall be achieved on an hourly basis. This requirement shall apply to all existing plants, including the ones commissioned before 2030. Temporal correlation can also be met if clearing prices are less than €20/MWh or 0.36 times the price of an EU ETS allowance.
  3. **Geographical correlation:** The installation generating renewable electricity under the renewables PPA is located: i) In the same or in an interconnected bidding zone, where day-ahead prices are equal or higher ii) in an offshore bidding zone interconnected with the bidding zone where the electrolyser is located.

90% renewable electricity in the bidding zone

- As shown above, if the bidding zone has a renewable electricity share of at least 90%, there are no further requirements for the hydrogen production to meet. It is therefore the simplest option for grid-connected electrolysis.

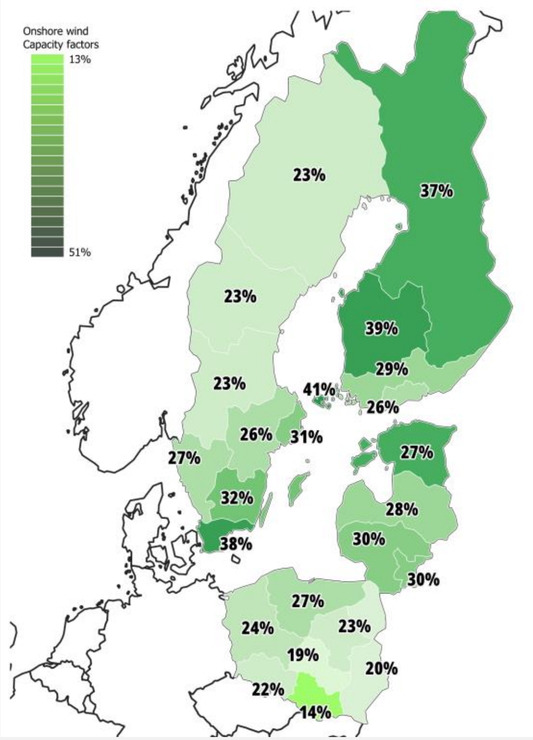
3.2 Onshore and Offshore production and LCOH

The high utilization of a wind farm is paramount for low-cost hydrogen production. The capacity factors obtainable in the Baltic area vary significantly, which have a strong influence on the business case for hydrogen production in the Nordics.

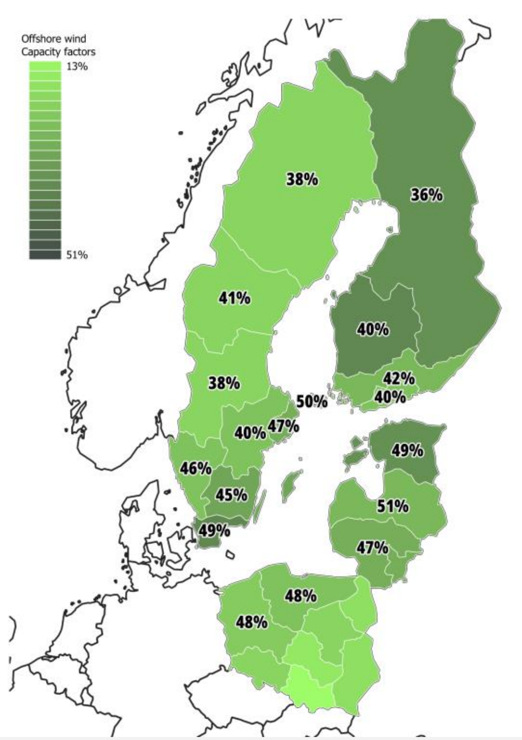
Capacity factors and their effect on LCOH

- To assess the wind resource and its effect on the LCOH the most important factor influencing the LCOH is the **capacity factor for the renewable plants**.
- The net capacity factor is the ratio of actual electrical energy output over a given period of time to the theoretical maximum electrical energy output over that period. The result is a dimensionless factor that describes the quality of a site in relation to the use of the resource.
- To assess these capacity factors several inputs need to be considered. One aspect is as mentioned the available natural wind resource at the specific site. This data has been assessed for this study using the data provided by Renewables.Ninja – a data source fed by the University of Delft and Imperial College in London.
- Another relevant factor is the technology that is considered. Here factors such as the height of the turbine tower (hub height), the blade length and the ratio between turbine size and blade length matter to determine the capacity factors.
- In the appendix of this study a list of technical parameters can be found that summarizes the parameters we have used for the assessment in this chapter.
- As the right-hand side graph shows, capacity factors (left for onshore wind and right for offshore wind) show a large discrepancy in the Baltic Sea area. For offshore wind the range of capacity factors is between 38% in the northern part and for good sites at around 50% in the more southern parts of the Baltic. The onshore factors range between 39% in parts of Finland and 18% in parts of Poland. It is obvious from the data that the wind potential in Sweden is lower than in Finland.
- Given these inputs, as mentioned above, we explain further the results of the LCOH analysis and provide interpretation of these results.

Onshore wind



Offshore wind



Source: DNV analysis based on Renewables.Ninja

3.2 Onshore and Offshore production and LCOH

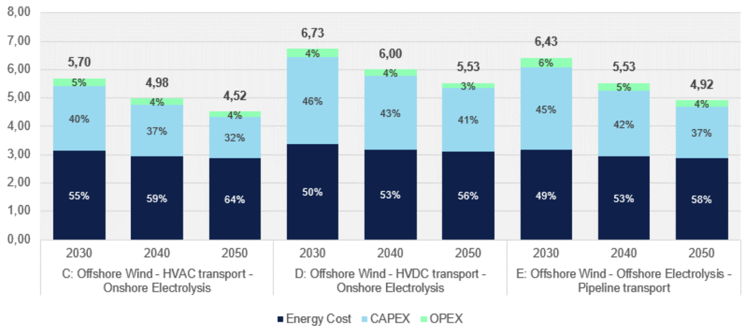
The lower capacity factors offshore in the Baltics, compared to the North Sea, significantly influence the LCOH – even though CAPEX is lower with shorter distances to shore. In addition, for the Baltic area, electrolysis is generally land based than sea based – which also impacts potential pipeline routings.

Offshore wind details

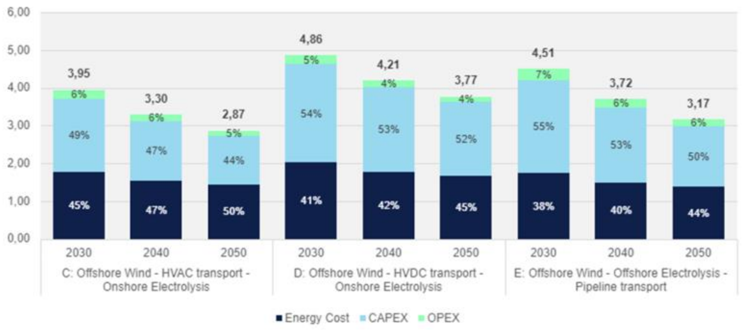
- In general, the distances to shore in the Baltic Sea are comparably small. The widest distances occur between Latvia and Sweden which are about 134 nm (248 km) apart from each other so that an offshore wind farm build in the middle of the Baltic would here have a connection distance of ~ 125km. In the Gulf of Bothnia and the Gulf of Finland the distances are significantly lower.
- Moreover, the water depths in the Baltic Sea have a much greater variance. Especially in the Scandinavian areas around Sweden depths are often above 50 metres close to shore (20 km). So, the depth conditions differ from the Norths Sea area – as do the soil conditions.
- These two aspects in general lead to rather close distances to shore that will likely prevail. Therefore, the economically best production option in the Baltic Sea is generally **offshore wind with an onshore based hydrogen production**.
- Our analysis for the entire Baltic shows that offshore based electrolysis will in most cases not be economic in the Baltic Sea due to the rather close distances to shore.
- This is shown in the graph on the right-hand side by the example of the southern tip of Sweden (NUTS SE 22).
- For reference we have additionally taken the same model from the previous study on the North Sea potential, where we worked with 5.000 full load hours (CF 57%) and show here the results for 25 km shore distance with a capacity factor adjusted to the location of SE 22 (CF 49%). As it can be seen the impact of the capacity factor on the LCOH is significant.
- The next slide displays the obtainable LCOH for the offshore areas adjacent to the Baltic Sea regionalized for the respective countries (with electrolyzers placed onshore and an AC connection). They show the result for three time slices – 2030, 2040 and 2050. The slide thereafter does the same for onshore wind production.

LCOH Breakdown – Offshore Wind to Hydrogen (25 km Distance to Shore) (€/kg)

Baltic SE 22



North Sea

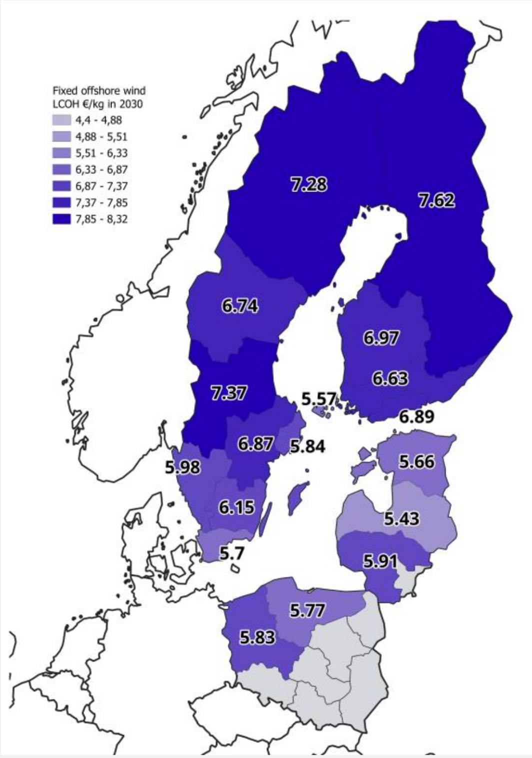


Source: DNV

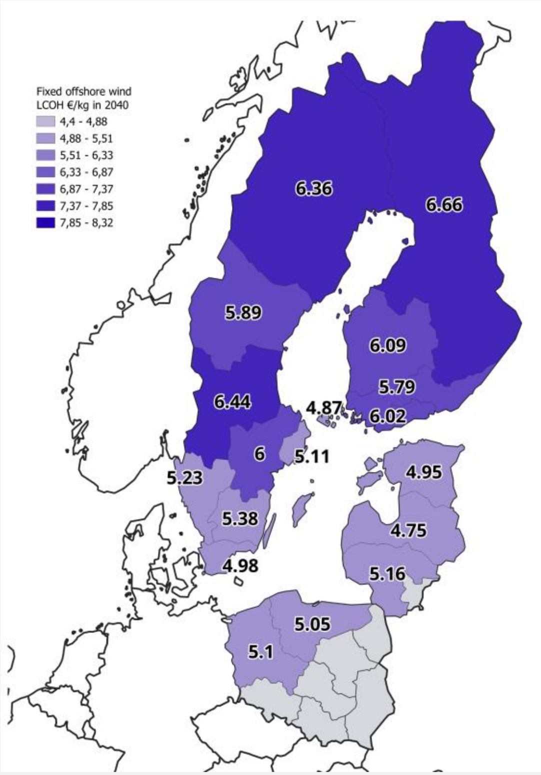
3.2 Onshore and Offshore production and LCOH

For **offshore** wind-based hydrogen production the southern Swedish, southern Finish and Polish waters provide the best resources.
LCOHs of around 4.5 Euro are achievable by 2050 for the better areas. The LCOH reduction is achieved by learning rates for the electrolysis.

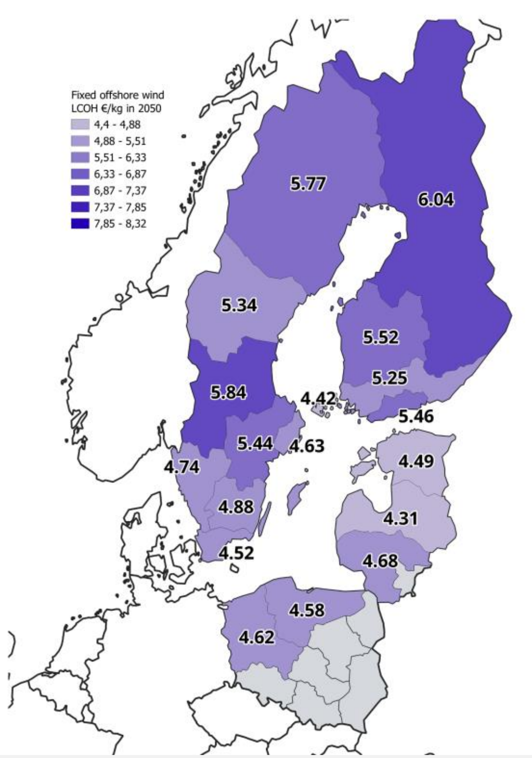
2030



2040



2050

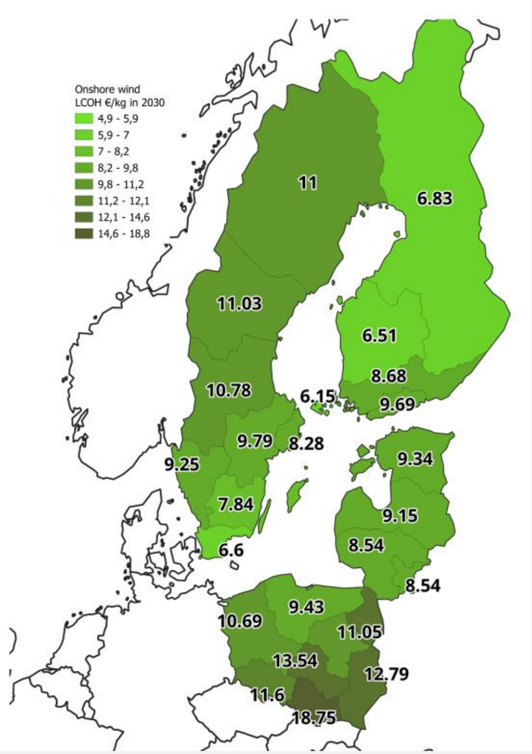


Source: DNV analysis

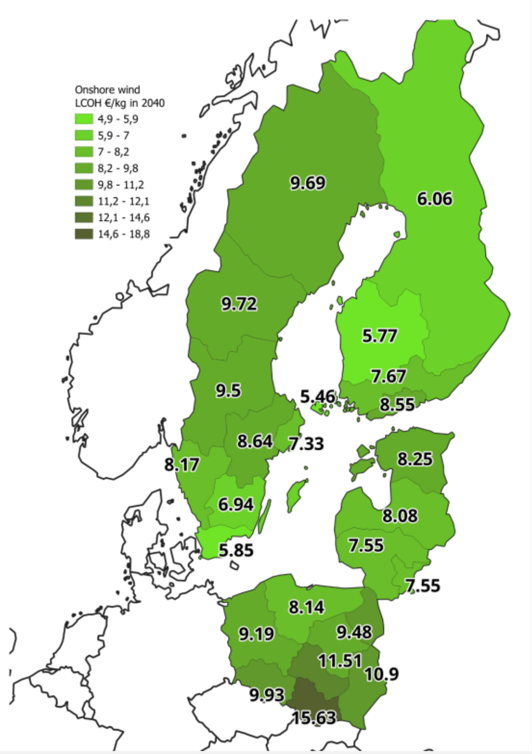
3.2 Onshore and Offshore production and LCOH

For **onshore** wind we have a very diverse picture on the LCOH in the Nordic region as wind patterns differ largely depending on the region.

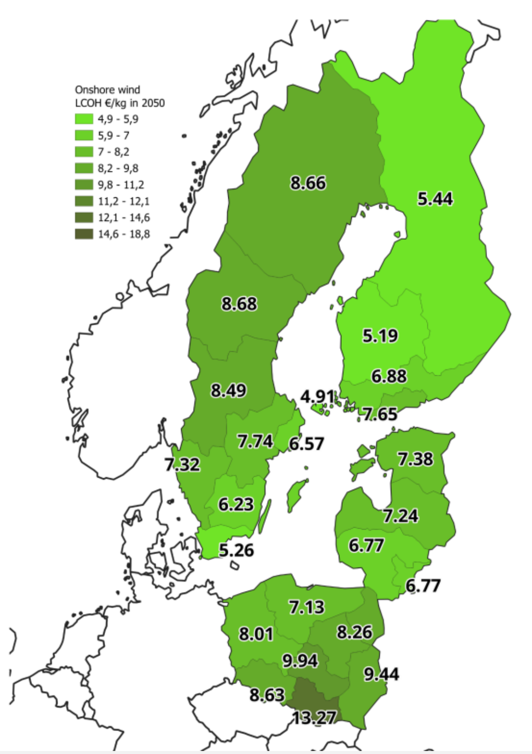
2030



2040



2050



Source: DNV analysis

3.2 Onshore and Offshore production and LCOH

In the Baltic area, offshore wind is a rather cost intensive way of producing green hydrogen. For most locations, onshore wind production shows a lower LCOH.

Interpretation of results

- On the last two slides we have shown that the production costs for hydrogen from offshore wind are in the best cases around 4€/kg – 4,5 €/kg in 2050. Many areas – especially in Sweden – do not show favourable hydrogen production costs. Therefore, considering the analysis of the chapter before, it can be doubted if Sweden – even if it would ramp up its wind development plans – would be able to produce hydrogen competitively compared to other regions.

- On the right-hand side a more detailed example of the LCOH for two regions is shown. The upper graph shows the southern tip of Sweden. This graph is now also considering different connection options. As it can be seen here offshore wind with an AC connection and onshore electrolysis is the most economical way to produce hydrogen – very closely followed by onshore wind.

- The lower graph shows a region in central Finland. As can be seen, here the LCOH is slightly lower for onshore wind than in southern Sweden whilst the offshore production in this region is significantly more expensive. These data clearly indicate that there will be a bigger variance in the production means (onshore and offshore) for hydrogen in the Baltic area.

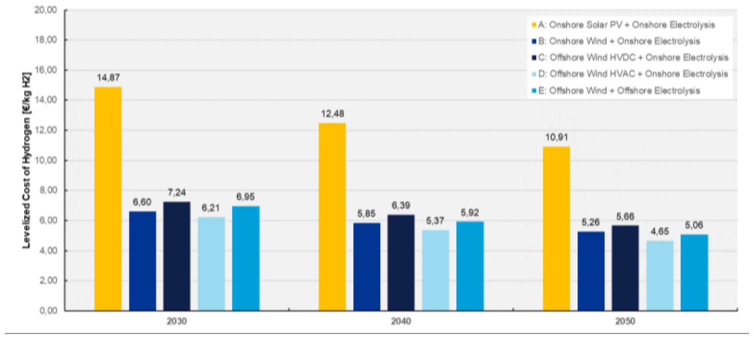
- A point to highlight once again is that even in the stronger wind region in Southern Sweden, with closer shore distances compared to the North Sea, the offshore production of hydrogen is not competitive.

- Overall **onshore wind** seems to be the most favourable solution for the region, with the given capacity factors and production costs. This can mainly be explained by comparably low capacity factors for offshore wind in the region so that the higher CAPEX needs are not fully offset by potentially higher energy yields.

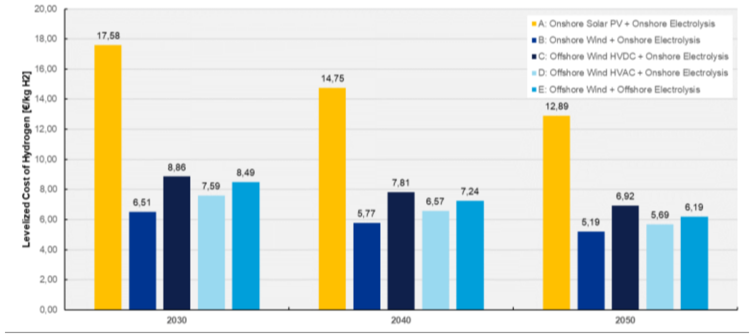
- For onshore wind, from a technical standpoint, it also needs to be considered that there may still be some technological development that could positively affect the LCOHs that have been shown on the previous slide. DNV observes that onshore wind turbines are getting bigger because of economic factors. The size of new onshore turbines has increased over the last years, now often with rotor diameters of 160 - 172 m and with a hub height of about 160 m. The nameplate capacities have also increased to a range of 5.5 - 7.2 MW. In areas with lower wind speed the rated power / rotor area ratio is smaller so that in combination with higher hub heights increasing capacity factors can be obtained, which would reduce the cost shown here.

Levelized cost calculations for hydrogen value chains in NUTS2 region SE22

Sweden



Finland



Source: DNV

3.2 Onshore and Offshore production and LCOH

Alternative case – Power taken from the grid as per RED II.

This chart shows the LCOH for grid-based hydrogen production in Sweden and Finland.

If the bidding zone has a **renewable electricity share of at least 90%**, there are no further requirements for the hydrogen production to meet. It is therefore the simplest option for grid-connected electrolysis. We expect some bidding zones in Sweden and Finland to meet these requirements in the future**. In this case, calculating the LCOH based on grid electricity prices is most appropriate.**

Alternatively, a **bidding zone may have very low emissions, due to nuclear power plants**, or other low-carbon non-renewable generation. If the average emission intensity of electricity in a bidding zone is 18 gCO2e/MJ, then green hydrogen production facilities are not required to be connect to new renewables facilities (additionality). However, they still need to have renewable PPAs in place, and match hydrogen production to the renewable generation on an hourly basis (from 2030). We also expect some bidding zones in Finland and Sweden to meet this requirement. **In this case, it is still most relevant to calculate the LCOH based on the cost of onshore wind (or other renewable generation options).**

As can be seen, the levelised cost of hydrogen production from grid electricity is considerably lower than hydrogen produced from dedicated onshore wind, offshore wind or solar. Grid-connected electrolysis costs on average 62% less than the two cheapest options on the previous slide (onshore wind and offshore wind with a HVAC connection). Of this, a 44% decrease is caused by the lower LCOE, whereas the remaining 19% is caused by the higher capacity factor of the electrolyser (90% versus 40%).

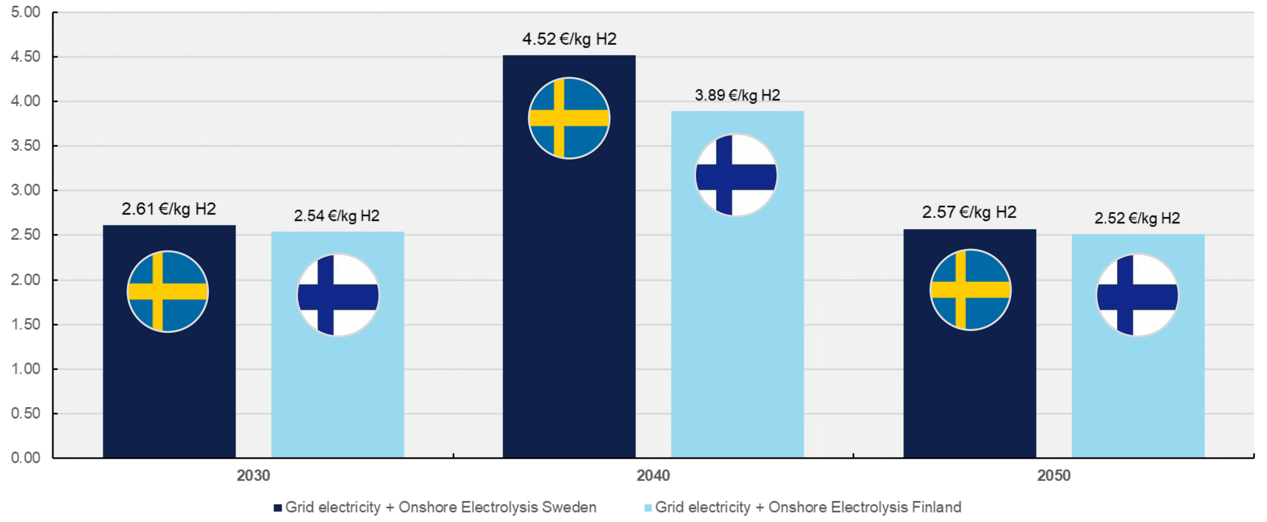
When exactly various bidding zones in Sweden and Finland will reach the 90% renewable criterion is uncertain. However, zones where this criteria is met will have a cost-competitive means of hydrogen production, which could be an incentive to export surplus hydrogen from these regions to Central Europe.

Country	2030	2040	2050	Unit
Sweden	26.0	68.0	34.5	€/MWh
Finland	24.7	55.9	33.5	€/MWh

Source: DNV

Levelized cost of hydrogen (€/kg H2)

Levelized cost calculations for grid-based hydrogen value chains in Sweden and Finland, complying with the 90% renewables criterion in the REDII directive



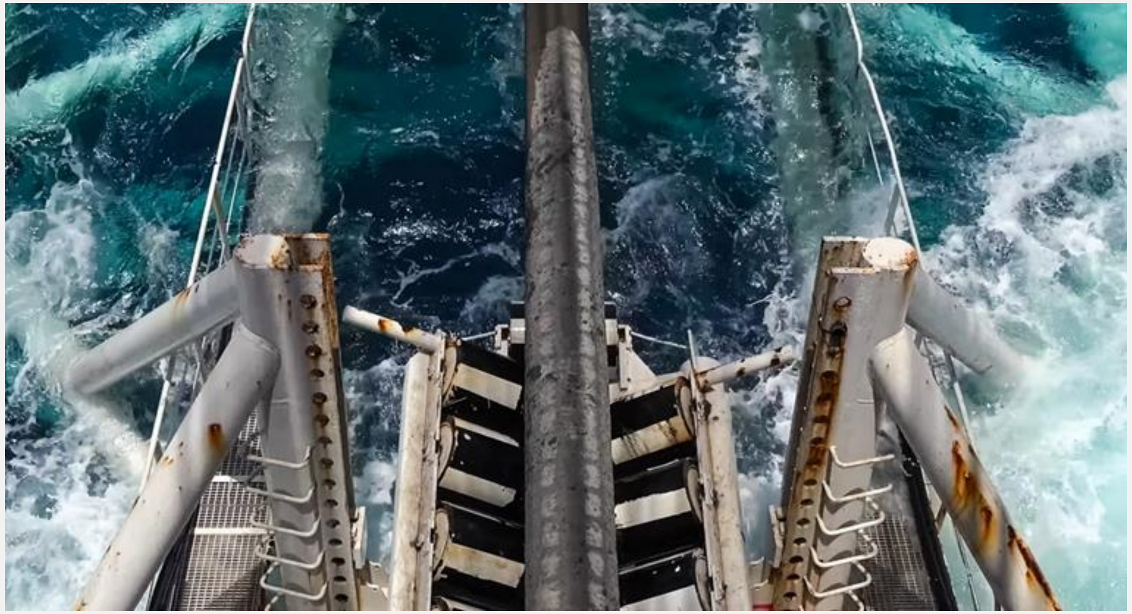
Source: DNV

3. Baltic states’ green hydrogen production cost - Conclusions

The LCOH analysis shows that hydrogen from the Baltic Sea countries is likely competitive compared to imports from other areas of the world.

Conclusions

- Comparing the LCOH of the various hydrogen production options, it becomes apparent that if we look at directly connected RES, Finland in general is able to produce renewable hydrogen at the lowest cost. Therefore, economically, directly connected projects in Finland are better suited for hydrogen production than Swedish ones.
- In terms of offshore wind, the Baltic states and Southern Sweden can also achieve relatively low LCOH, compared with the rest of the region.
- The overall cost pattern shows that the best combined LCOH with directly connected RES could be achieved when sourcing hydrogen from Finland and the Baltic states. Overall, however, the analysis shows that, for directly connected RES, hydrogen production costs are significantly higher than areas of the world where production can make use of cheap solar PV or higher wind capacity factors, as for example in the North Sea.
- **This picture changes significantly with EU regulation. The RED II criteria allow grid electricity to be used in bidding zones with a RES share of more than 90%. Given that the region already runs on a very high share of renewable and low carbon electricity supply, electrolysers can in some cases operate with electricity directly from the grid. This enables a much lower LCOH, which makes the region as a whole more attractive for low-cost hydrogen production.**
- Therefore, from an economic as well as a strategic viewpoint, it is reasonable to take offshore and onshore wind resources in the Baltic area into account for European hydrogen production.
- As the LCOHs here do not account for the system cost in order to transport and store the hydrogen – the system cost for transported hydrogen will be somewhat higher than the LCOH explained in this chapter – we will address these additional costs and the options to transport the hydrogen to Central Europe in chapter 4 of this study.



Source: DNV

4.1 Alternative pipeline routes

This chapter provides an analysis of the potential routes through which hydrogen can be transported from northern Scandinavia to Central Europe by comparing cost effectiveness and required transport capacities.

After looking at the potential for hydrogen production in the northern areas of the Baltic Sea in the first chapter and analysing the specific production costs in the previous chapter, this chapter will focus on pipeline-based hydrogen transport to Central Europe.

The surplus potentials per NUTS 2 region, which were generated in the course of the analyses in Chapter 1, are used as a starting point for possible pipeline routings. These NUTS-based surplus potentials are presented on the following two slides.

As the resulting surplus potential in Sweden is very small and fragmented, in this chapter we only consider the export potentials from Finland and the Baltic States.

For the routings we rely on potential routes that have been discussed in the various publications of the European Hydrogen Backbone initiative. The various possibilities are depicted in the map on the right. Additionally, an optimised offshore pipeline is investigated.

As such this chapter aims to compare possible pipeline routings on the above basis with regard to their characteristics and costs, so that system LCOH can be calculated for the procurement of hydrogen from the northern area of the Baltic Sea.

The chapter is structured as following:

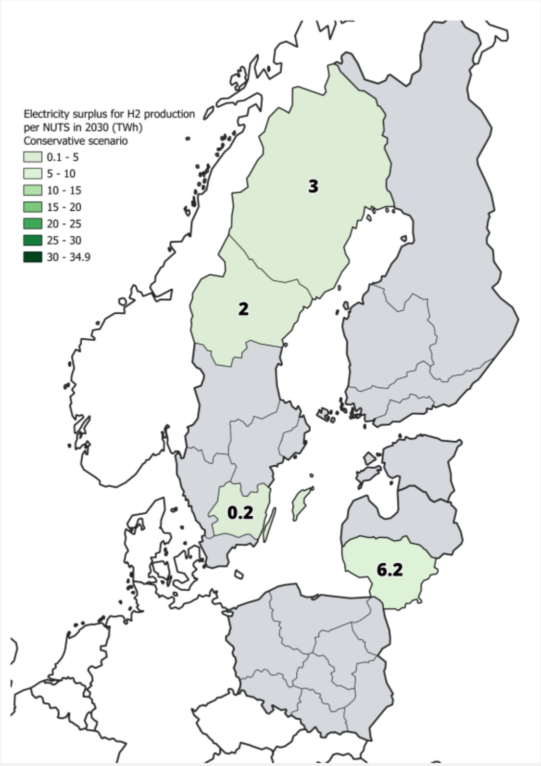
1. As outlined before the next two slides will show in a recap the hydrogen export potentials from the countries under investigation per scenario.
2. Then we will outline more details about the routes that we have taken into consideration out of the European Hydrogen Backbone initiative.
3. As a last step the resulting cost of both options are calculated and compared.
4. The chapter ends with some conclusions on potential pipeline routings and aspects that may influence routing decisions.

Source: DNV, based on European Hydrogen Backbone

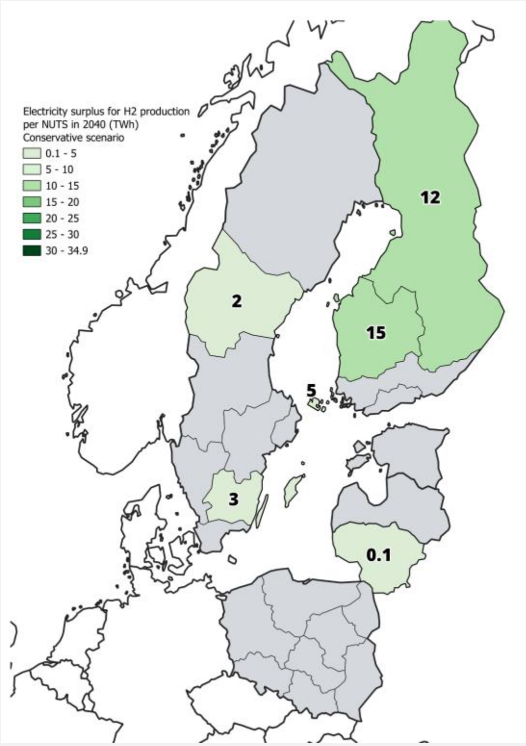
4.1 Alternative pipeline routes

The starting points for the pipeline routing analysis are the electricity surplus patterns shown below, taken from chapter 2 – **Conservative Scenario**

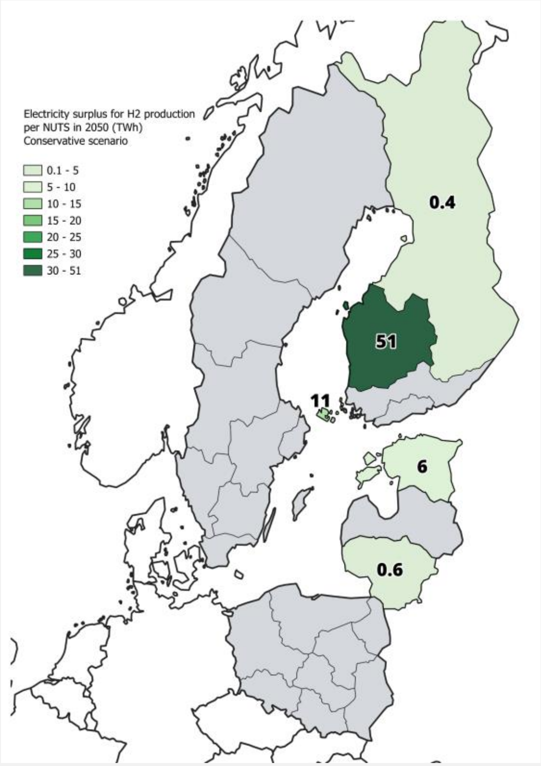
2030



2040



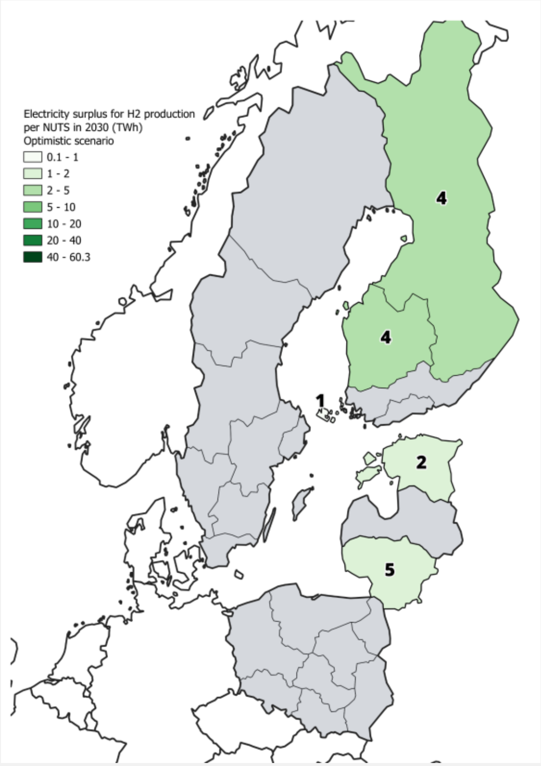
2050



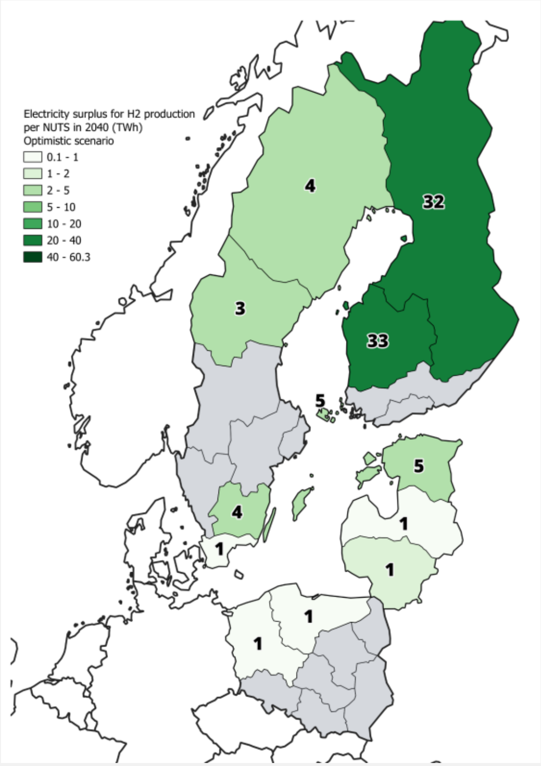
4.1 Alternative pipeline routes

The starting points for the pipeline routing analysis are the electricity surplus patterns shown below, taken from chapter 2 – **Optimistic Scenario**

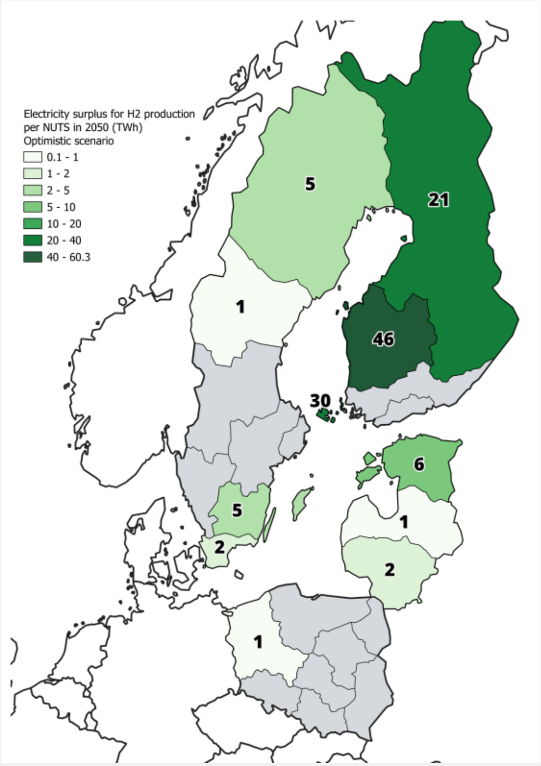
2030



2040



2050



4.1 Alternative pipeline routes

In the Conservative Scenario, a total of 40 TWh of hydrogen becomes available for export by 2050. In the Optimistic Scenario, hydrogen export potential reaches 62 TWh by 2050.

Based on the maps shown on the previous pages, the table on the right shows total hydrogen surplus, generated from the surplus electricity in Finland, which is the starting point for the pipeline routing analysis. It was found that there exists effectively no significant surplus hydrogen in Sweden across all analysed years and scenarios, which would merit a pipeline connecting to this area.

Impact of capacity factor
In the analysis, the pipelines are dimensioned such that they can operate flexibly to transport hydrogen that is produced intermittently following the load profile of onshore wind in Finland. This means that the pipeline will have to handle the peak capacity, but most of the time will operate at partial throughput. This results in an assumed capacity factor of 40% for this analysis – in line with onshore wind availability.

A higher capacity factor for a pipeline of a given size leads to a lower levelised cost of hydrogen transport. This is because while capital investments remain the same, the volume of hydrogen that is transported increases, lowering the price per kg transported. The capacity factor could realistically be increased by using more complementary sources of renewable electricity such as hydropower or with hydrogen produced in zones with >90% renewables generation, or even by buffering hydrogen in geological storage and hence shaving the peaks off the production profile, reducing the need for 'over dimensioned' pipelines.

Year	Scenario	Surplus Electricity Finland [TWh_{el}]	Conversion efficiency [% LHV]	Surplus Hydrogen Finland [TWh_{H2}/yr LHV]	Required nominal pipeline capacity* [GW_{H2}]
2030	Conservative	0.0	64.1%	0.0	0.0
2040	Conservative	32.0	64.2%	20.5	5.9
2050	Conservative	62.4	64.3%	40.1	11.4
2030	Optimistic	8.6	64.1%	5.5	1.6
2040	Optimistic	70.0	64.2%	44.9	12.8
2050	Optimistic	97.0	64.3%	62.4	17.8

* Pipeline capacity based on a capacity factor of 40%

4.1 Alternative pipeline routes

European gas grid operators collaborate through various initiatives to realise north-south oriented hydrogen transport corridors, connecting Sweden and Finland to Central Europe. As no significant surplus hydrogen in Sweden was found, this study looks at routing from central Finland to Central Europe.

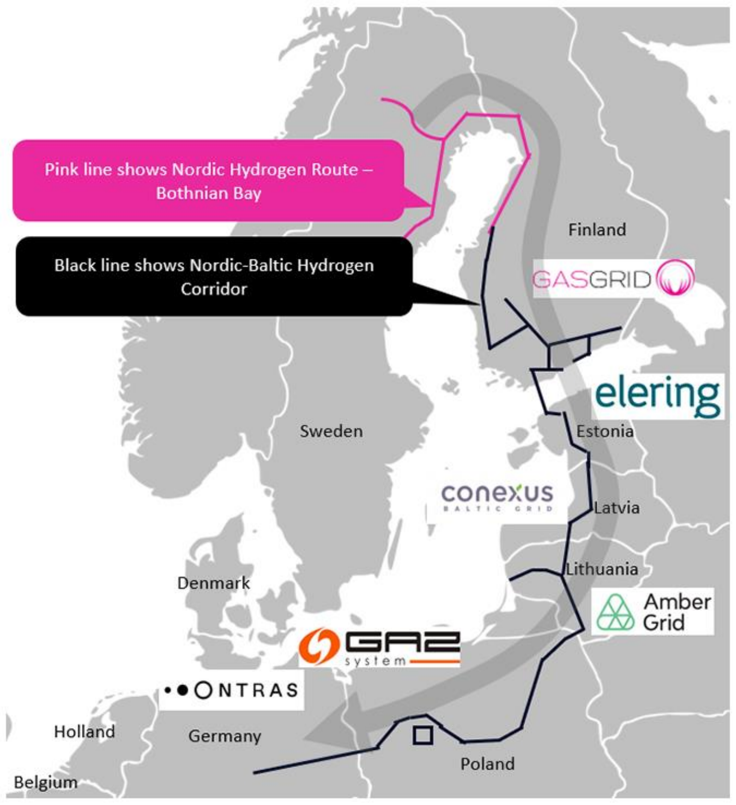
As pointed out in the introduction there are different routes that could be established to transport hydrogen from the northern Baltic Sea to Central Europe. These routes are especially the following:

- The **Nordic-Baltic Hydrogen Corridor** initiative foresees a (largely) onshore hydrogen pipeline connecting Finland and Germany through the Baltic states and Poland.
- The **Baltic Hydrogen Collector** initiative foresees an offshore hydrogen pipeline through the Baltic Sea, central Sweden and Finland to Germany.
- The **Nordic Hydrogen Route** initiative foresees an onshore hydrogen pipeline connecting the north of Sweden and Finland to the Nordic-Baltic Hydrogen Corridor in Finland and the Swedish hydrogen backbone in Sweden, which could ultimately be connected via central Sweden and Denmark to Germany.

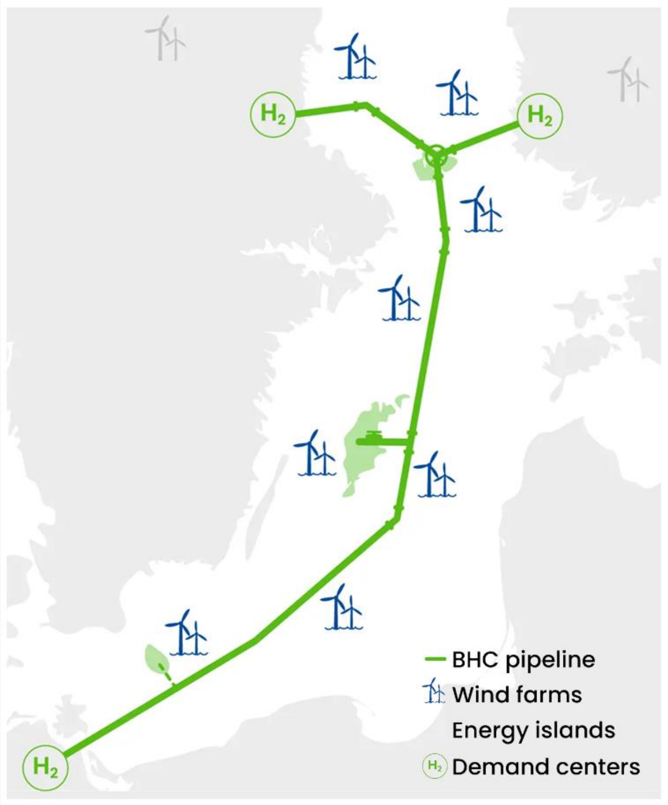
The initiatives are integrated into the **European Hydrogen Backbone** vision.

As a result of the surplus analysis, it was found that there exists effectively no significant surplus hydrogen in Sweden across all analysed years and scenarios, and therefore the Nordic Hydrogen Route is not taken into consideration for further analysis of pipeline routing to Central Europe. This outcome could be significantly altered if Sweden decides to speed up the deployment of renewable energy compared to current plans.

In this report, we refer to the Nordic-Baltic Hydrogen Corridor as the “onshore route” and the Baltic Hydrogen Collector as the “offshore route”.



Source: (1) Ontras (Nordic-Baltic Hydrogen Corridor) (2) Nordic Hydrogen Route



Source: Image adapted from Baltic Hydrogen Collector

4.1 Alternative pipeline routes

Based on the identified surplus in Finland, two pipeline routes to Central Europe are analysed, routed either through a (largely) onshore pipeline crossing the Baltic states or an offshore pipeline crossing the Baltic Sea.

For comparison's sake, in this analysis the starting point of the onshore route and the offshore route is chosen to be the same point near the Finnish city of Turku. Both routes connect to the planned Finnish onshore hydrogen transport grid that will come from the north of Finland.

- The **offshore route** starts by connecting Turku to the island of Åland. From there two parallel pipelines of approximately 760 kilometres length pass the Baltic Sea and connect to the Danish island of Bornholm. From there, again a set of two pipelines connect to the German mainland. The total length of a single trace of pipelines is approximately 1,000 km. The total length, including a dual trace of pipelines is approximately 1,900 km. In this study, both the prospect of a single and dual trace are analysed. Additionally, the possibility of having a single optimised offshore pipeline is investigated. This pipeline will be dimensioned such that it is able to transport the expected surplus for all analysed scenarios and years. Furthermore, the optimised pipeline will feature a branch from Bornholm connecting to the Niechorze-Pogorzelica area in Poland.

- The **onshore route** starts by connecting Turku to Helsinki where the Finnish gulf is crossed by an offshore pipeline segment that connects Helsinki to Tallinn. From there, a newbuilt pipeline through Estonia and Latvia transports the hydrogen until a repurposed natural gas pipeline segment in Latvia of approximately 100 kilometres is encountered. A newbuilt pipeline that crosses the borders of Latvia and Lithuania connects to a second repurposed natural gas pipeline segment of around 100 kilometres length is encountered. From there on, newbuilt pipeline segments through Lithuania and Poland connect to the German border at Eisenhüttenstadt. The total length of the onshore route is approximately 2,000 km.

On the following pages we will investigate the **necessity** and **cost-effectiveness** of having these north-south oriented hydrogen transport corridors in parallel, or whether having any single one of them will provide sufficient transport capacity based on the surplus hydrogen production scenarios in Finland that were derived in this report.

Source: DNV, based on European Hydrogen Backbone

4.2 Technical aspects and cost of alternative pipeline routes

For the **offshore route**, dual (non-optimised) pipelines would satisfy requirements for surplus transport from Finland for all scenarios, whereas a single pipeline would satisfy the 2030 optimistic and 2040 conservative scenarios (1/2).

Based on data from the European Hydrogen Backbone reports, an estimate can be provided of the transport capacity and levelized cost of transport of the **offshore route**. In our analysis we consider the possibility of constructing a **single pipeline**, or **dual pipelines**, denoted as **pipeline A** and **pipeline B**. The table on the next page gives insight into the different pipeline segments.

For calculating the hydrogen transport capacity, the European Hydrogen Backbone reports have the following assumptions:

- Nominal capacity of 16.9 GW_{H2}.
- A capacity factor of 75% for newbuilt pipelines of 48 inch (80 bar), meaning an actual capacity of 12.7 GW_{H2}.

This leads to an annual transport capacity of 111.0 TWh_{H2}/yr per pipeline single route, based on full utilization, and given the pipeline capacity factor of 75%. Considering two parallel pipelines, this amounts to 222.1 TWh_{H2}/yr (33.8 GW).

However, the actual capacity is likely to be lower than this, as green hydrogen connected to onshore wind will only be produced when the wind is blowing. At the expected capacity factor for Finnish onshore wind of 40%, the annual transport capacity would amount to **59.2 TWh_{H2}/yr** and **118.4 TWh_{H2}/yr** for one and two parallel pipelines, respectively.

From this we can conclude that the offshore route can satisfy the expected hydrogen transport demand from the surplus originating from Finland in the following scenarios:

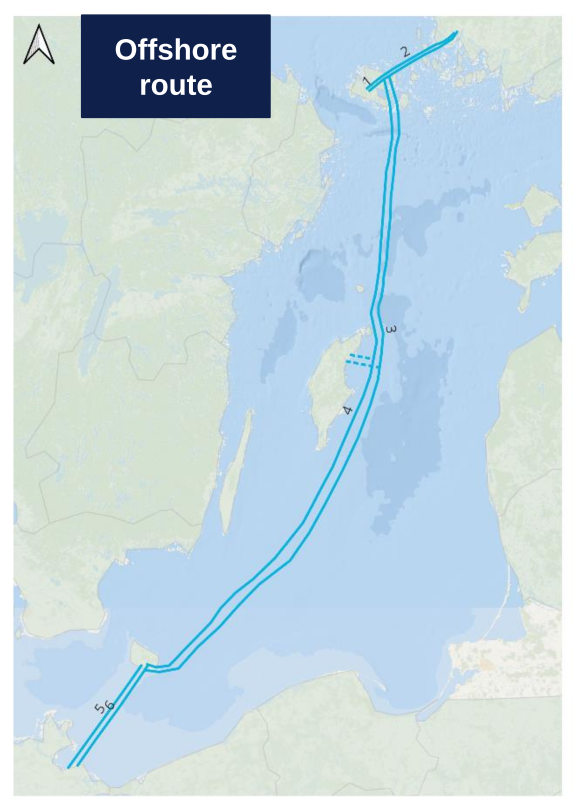
- Single pipeline (A or B): All scenarios are satisfied, except 2050 optimistic scenario.
- Dual pipelines (A and B): All scenarios are satisfied.
  Note that at a maximum operating pressure of 80 bar, intermediate recompression needs to be included on the island of Gotland in Sweden to transport hydrogen through the long ~780 km pipeline.

The next section will analyse the levelised cost of hydrogen transport for the (non-optimised) offshore pipeline route.

Year	Scenario	Surplus Finland [TWh_{H2}/yr LHV]	
	Number of pipelines	Single	Dual
2030	Conservative	0.0	0.0
2040	Conservative	20.5	20.5
2050	Conservative	40.1	40.1
2030	Optimistic	5.5	5.5
2040	Optimistic	44.9	44.9
2050	Optimistic	62.4	62.4

Transport capacity sufficient

Transport capacity NOT sufficient



Source: DNV, based on European Hydrogen Backbone

4.2 Technical aspects and cost of alternative pipeline routes

For the **offshore route**, dual (non-optimised) pipelines would satisfy requirements for surplus transport from Finland for all scenarios, whereas a single pipeline would satisfy the 2030 optimistic and 2040 conservative scenarios (2/2).

Pipeline A

ID	Country	Length (km)	Type	Diameter (inch)	Nominal Capacity (GW_{H2})	Capacity factor onshore wind (%)	Actual capacity (GW_{H2})	Actual maximum throughput (TWh_{H2}/yr)	Operating pressure (bar)	CAPEX (M€)
1	FI	111	Offshore new	48	16.9	40%	6.8	59.2	80	650
3	SE	760*	Offshore new	48	16.9*	40%	6.8	59.2	80*	4,454
5	GE	131	Offshore new	48	16.9	40%	6.8	59.2	80	768
	Sum	**1,002**								**5,872**

Pipeline B

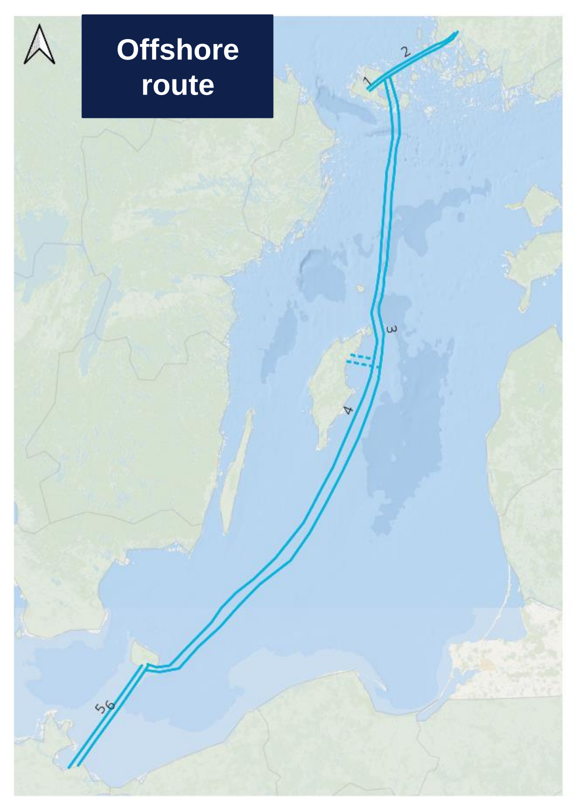
ID	Country	Length (km)	Type	Diameter (inch)	Nominal Capacity (GW_{H2})	Capacity factor onshore wind (%)	Actual capacity (GW_{H2})	Actual maximum throughput (TWh_{H2}/yr)	Operating pressure (bar)	CAPEX (M€)
2	FI	108	Offshore new	48	16.9	40%	6.8	59.2	80	633
4	SE	781*	Offshore new	48	16.9*	40%	6.8	59.2	80*	4,577
6	GE	126	Offshore new	48	16.9	40%	6.8	59.2	80	738
	Sum	**1,015**								**5,948**

Pipeline A + B

ID	Country	Length (km)	Type	Diameter (inch)	Nominal Capacity (GW_{H2})	Capacity factor onshore wind (%)	Actual capacity (GW_{H2})	Actual maximum throughput (TWh_{H2}/yr)	Operating pressure (bar)	CAPEX (M€)
	Sum	**2,018**	Offshore new	48	33.8	40%	13.5	118.4	80*	**11,820**

Note that this table highlights the main limiting factor for the offshore route, which is assumed to be the capacity factor of onshore wind in Finland. The corresponding table for the onshore route highlights the main limiting factor, which for the onshore route is assumed to be the pipeline capacity for certain segments. Hence these tables are slightly different.

*These figures are taken from the European Hydrogen Backbone report but don't fit the capacity (pressure drop) calculation for the full ~780 km pipeline. This would require recompression on the island of Gotland. The normal operation pressure for these long-distance offshore pipelines is 150 to 250 bar, as analysed in the optimised pipeline scenario on the next pages.



Source: DNV, based on European Hydrogen Backbone

4.2 Technical aspects and cost of alternative pipeline routes

The levelised cost of hydrogen transport for the (non-optimised) **offshore route** from Finland to Germany is 0.21 €/kg H2 at a capacity factor of 75% versus 0.40 €/kg H2 at a capacity factor of 40%.

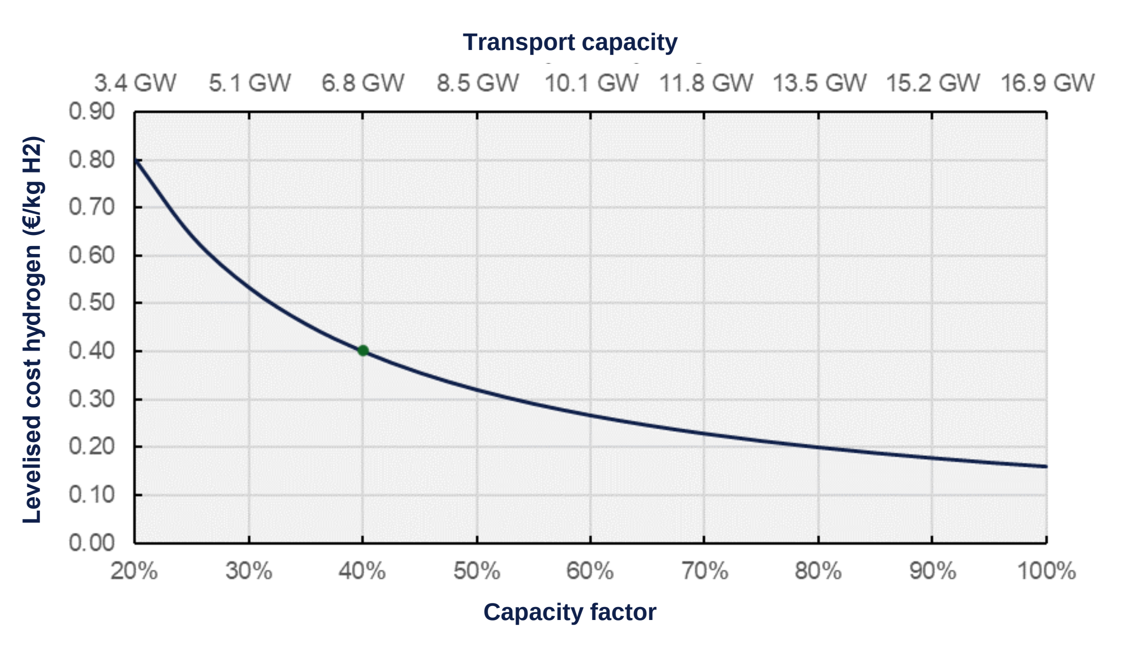
Assumptions

Calculating the levelised cost of hydrogen transport is based on the following data:

- The 'medium' scenario of the hydrogen transport cost estimates from the European Hydrogen Backbone report (see Appendix).
- Pipeline OPEX of 1.0% of CAPEX per year; compression OPEX of 1.7% of CAPEX per year.
- A discount rate of 10%, equal to the discount rate used in the levelized cost analysis presented earlier in this report.
- A depreciation period of 40 years for the pipelines and a depreciation period of 25 years for the compressors.

Results

- Total CAPEX cost (Pipeline + Compression)
  - Single (non-optimised) pipeline: A total CAPEX cost of M€ 5,872 (pipeline A) or M€ 5,948 (pipeline B)
  - Dual (non-optimised) pipelines: A total CAPEX cost of M€ 11,820
- Levelized Cost of Hydrogen Transport will be very close for all three options, as the transport capacity scales proportionally with the number of installed pipelines and pipeline A and B cost nearly the same.
  - At a capacity factor of 75%, the levelised cost of hydrogen transport will be 0.21 €/kg H2.
  - At a capacity factor of 40%, the expected capacity factor from Finnish onshore wind, the levelised cost of hydrogen transport will be **0.40 €/kg H2**.



Source: DNV. Green dot = capacity factor for Finnish onshore wind.

4.2 Technical aspects and cost of alternative pipeline routes

For the **offshore route**, a single **optimised pipeline** could satisfy requirements for surplus transport from Finland for all scenarios.

Pipeline A – Optimisation of capacity

The optimisation consists of the dimensioning of the single ~780 km pipeline (number 3 on the map), such that it can transport 65 TWh_{H2}/yr at a capacity factor of 40%, which means that a single pipeline is enough to transport the surplus hydrogen from Finland in all analysed scenarios and years. Furthermore, the optimised scenario includes a branch from the island of Bornholm to the Niechorze-Pogorzelica area in Poland, to connect to the onshore hydrogen grid there. This pipeline is operated at 170 bar. This optimisation omits the need for recompression on the island of Gotland in Sweden. The other, shorter pipelines on the route are operated at a pressure of 80 bar to meet the transport requirements.

The calculation was performed based on the ASME B31.12 standard, option A. This yielded an operating pressure of 170 bar, and subsequently a wall thickness of 60.13 mm. This is outside the standardized range of pipeline wall thicknesses available on the market, but not unseen in the industry. For instance, the Langeled pipeline that runs between the UK and Norway features similar design specifications. The specific costs of the optimised offshore pipeline and the Langeled pipeline yield similar results.

Note: Calculation option A in ASME B31.12 might be considered as conservative. Future expansion of this standard that is tailored to offshore hydrogen pipelines might yield different results.

Specifications of the 780 km pipeline from the Åland islands to Bornholm

Variable	Value	Unit
Nominal capacity	18.6	GW_{H2}
Length	780	km
Steel type	X52	-
Internal diameter	1098.9	mm
External diameter	1219.2 (48)	mm (inch)
Wall thickness	60.13	mm
Corrosion allowance	5.00	mm
Wall roughness	0.05	mm
Design pressure (+tolerance)	170 (+5)	bara
Inlet pressure	170	bara
Outlet pressure	61.8	bara
Operating temperature	10	°C

Source: DNV

Source: DNV, based on European Hydrogen Backbone

4.2 Technical aspects and cost of alternative pipeline routes

For the **offshore route**, a single **optimised pipeline** could satisfy requirements for surplus transport from Finland for all scenarios.

Pipeline A – Optimised

ID	Country	Length (km)	Type	Diameter (inch)	Nominal Capacity (GW_{H2})	Capacity factor onshore wind (%)	Actual capacity (GW_{H2})	Actual maximum throughput (TWh_{H2}/yr)	Operating pressure (bar)	CAPEX (M€)
1	FI	111	Offshore new	48	18.6	40%	7.4	65.0	80	650
2	SE	760	Offshore new	48	18.6	40%	7.4	65.0	170	4,309
3	GE	131	Offshore new	48	18.6	40%	7.4	65.0	80	768
4	PL	128	Offshore new	48	18.6	40%	7.4	65.0	80	750
	Sum	**1,130**								**6,478**

Source: DNV, based on European Hydrogen Backbone

Note that this table highlights the main limiting factor for the offshore route, which is assumed to be the capacity factor of onshore wind in Finland. The corresponding table for the onshore route highlights the main limiting factor, which for the onshore route is assumed to be the pipeline capacity for certain segments. Hence these tables are slightly different.

4.2 Technical aspects and cost of alternative pipeline routes

The levelised cost of hydrogen transport for the **optimised offshore route** from Finland to Germany is 0.21 €/kg H2 at a capacity factor of 75% versus 0.39 €/kg H2 at a capacity factor of 40%.

Assumptions

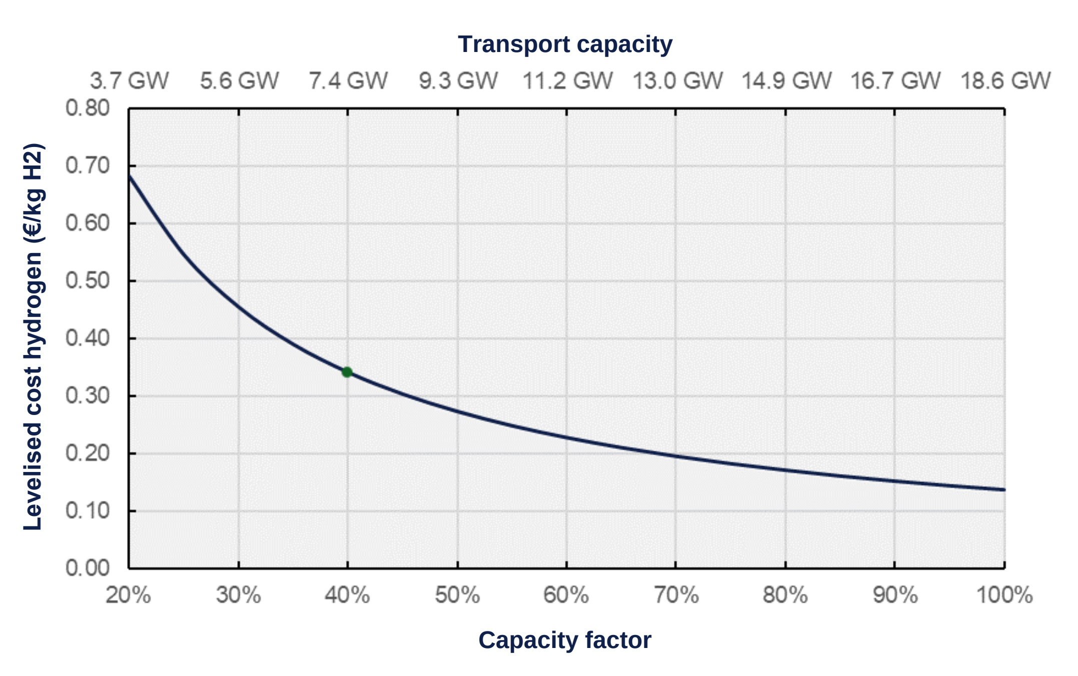
Calculating the levelised cost of hydrogen transport is based on the following data:

- Pipeline cost of 5.0 M€/km, based on the optimised design
- Compression cost of 549.4 M€, based on the optimised design
- Pipeline OPEX of 1.0% of CAPEX per year; compression OPEX of 1.7% of CAPEX per year, equal to the EHB figures.
- A discount rate of 10%, equal to the discount rate used in the levelized cost analysis presented earlier in this report.
- A depreciation period of 40 years for the pipelines and a depreciation period of 25 years for the compressors, equal to the EHB figures.

Results

- Total CAPEX cost (Pipeline + Compression)
  - Optimised pipeline (without branch to Poland): A total CAPEX cost of M€ 6,478
  - At a capacity factor of 75%, the levelised cost of hydrogen transport will be 0.21 €/kg H2.
  - At a capacity factor of 40%, the expected capacity factor from Finnish onshore wind, the levelised cost of hydrogen transport will be **0.39 €/kg H2**.

As can be seen, the levelised cost of the optimised pipeline is nearly equal to the levelised cost of the non-optimised pipeline. This is partly caused by the addition of the branch from Bornholm to Poland, and partly by the conservative cost estimations of the EHB reports regarding large offshore hydrogen pipelines.



Source: DNV. Green dot = capacity factor for Finnish onshore wind.

4.2 Technical aspects and cost of alternative pipeline routes

For the **onshore route** option, repurposed segments might cause a bottleneck. A transport capacity of 16.5 TWh H2/yr will only satisfy requirements for surplus transport from Finland for the 2030 optimistic scenario (1/2).

Based on data from the European Hydrogen Backbone reports, an estimate can be provided of the transport capacity and levelized cost of transport through the **onshore route**. The table on the next page gives insight into the different pipeline segments.

For calculating the hydrogen transport capacity, the European Hydrogen Backbone reports have the following assumptions:

- Capacity factor of 100% for newbuilt pipelines of 36 inch (50 bar), capacity factor of 75% for repurposed pipelines of 36 inch (50 bar), capacity factor of 75% for newbuilt pipelines of 48 inch (80 bar).

As can be seen in the table on the next page, the repurposed segments feature a lower operating pressure and therefore a lower transport capacity when compared to the other pipeline segments. These segments thus provide a bottleneck for transport capacity. Unless booster compressors are utilized to temporarily increase flow speed where possible, this constraint will determine the transport capacity of the full route.

- This leads to an annual transport capacity of 30.9 TWh_{H2}/yr, based on full utilisation within the limits of capacity factors given above, and the lowest capacity parts of the network (3.6 GW_{H2}).
- If the full route can be upgraded to 4.7 GW_{H2} transport capacity, a total of 41.2 TWh_{H2}/yr can be transported annually.

However, at the expected capacity factor for Finnish onshore wind of 40%, the annual transport capacity of a 4.7 GW_{H2} connection amounts to **16.5 TWh_{H2}/yr**.

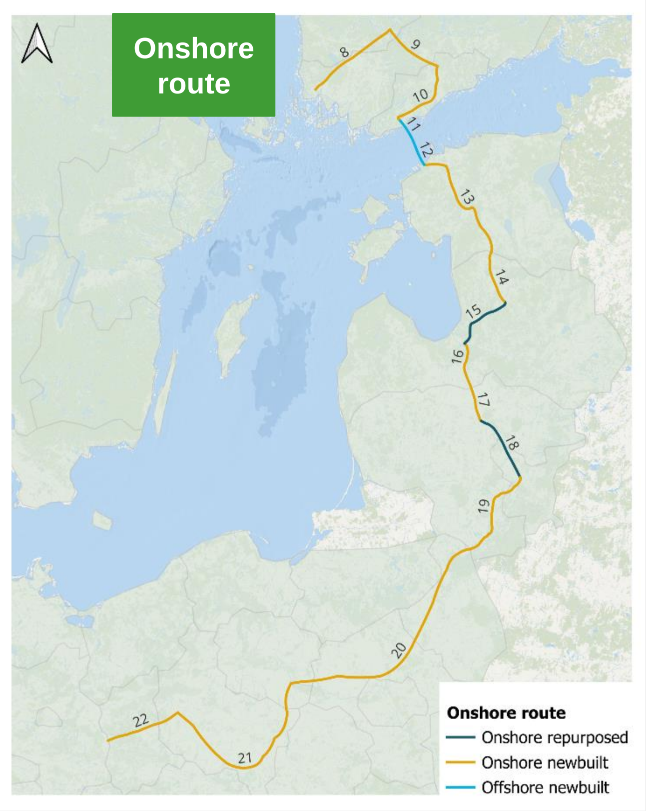
- If we compare this to the expected magnitude of the surplus from Finland, we can conclude that the onshore route can only satisfy the expected hydrogen transport capacity from the surplus from Finland in the 2030 optimistic (8.6 TWh_{H2}/yr) scenario (the conservative scenario does not envisage any surplus in 2030).

The next section will analyse the levelised cost of hydrogen transport for the onshore pipeline route.

Year	Scenario	Surplus Finland [TWh_{H2}/yr LHV]
2030	Conservative	0.0
2040	Conservative	20.5
2050	Conservative	40.1
2030	Optimistic	5.5
2040	Optimistic	44.9
2050	Optimistic	62.4

Transport capacity sufficient

Transport capacity NOT sufficient



Source: DNV, based on European Hydrogen Backbone

4.2 Technical aspects and cost of alternative pipeline routes

For the **onshore route** option, repurposed segments might cause a bottleneck. A transport capacity of 16.5 TWh H2/yr will only satisfy requirements for surplus transport from Finland for the 2030 optimistic scenario (2/2).

ID	Country	Length (km)	Type	Diameter (inch)	Nominal Capacity (GW_{H2})	Capacity factor (%)	Actual capacity (GW_{H2})	Actual maximum throughput (TWh_{H2}/yr)	Operating pressure (bar)	CAPEX (M€)
8	FI	146	Onshore new	48	16.9	75%	12.7	111.0	80	499
9	FI	92	Onshore new	48	16.9	75%	12.7	111.0	80	315
10	FI	115	Onshore new	48	16.9	75%	12.7	111.0	80	393
11	FI	39	Offshore new	48	16.9	75%	12.7	111.0	80	229
12	EE	41	Offshore new	48	16.9	75%	12.7	111.0	80	240
13	EE	193	Onshore new	48	16.9	75%	12.7	111.0	80	660
14	LV	79	Onshore new	36	4.7	100%	4.7	41.2	50	199
15	LV	99	Onshore repurposed	36	4.7	75%	3.5	30.9	50	53
16	LV	68	Onshore new	36	4.7	100%	4.7	41.2	50	171
17	LT	57	Onshore new	36	4.7	100%	4.7	41.2	50	144
18	LT	107	Onshore repurposed	36	4.7	75%	3.5	30.9	50	58
19	LT	148	Onshore new	36	4.7	100%	4.7	41.2	50	373
20	PL	394	Onshore new	48	16.9	75%	12.7	111.0	80	1,347
21	PL	288	Onshore new	36	4.7	100%	4.7	41.2	50	726
22	PL	116	Onshore new	48	16.9	100%	12.7	111.0	80	397
	Sum	**1,982**								**5,804**

Note that this table highlights the main limiting factor for the onshore route, which is assumed to be the pipeline capacity for certain segments (highlighted in red). The corresponding table for the offshore route highlights the main limiting factor, which for the offshore route is assumed to be the capacity factor of onshore wind in Finland. Hence these tables are slightly different.

Source: DNV, based on European Hydrogen Backbone

4.2 Technical aspects and cost of alternative pipeline routes

The levelised cost of hydrogen transport for the **onshore route**, from Finland to Germany, is 0.73 €/kg H2 at a capacity factor of 75% versus 1.37 €/kg H2 at a capacity factor of 40%.

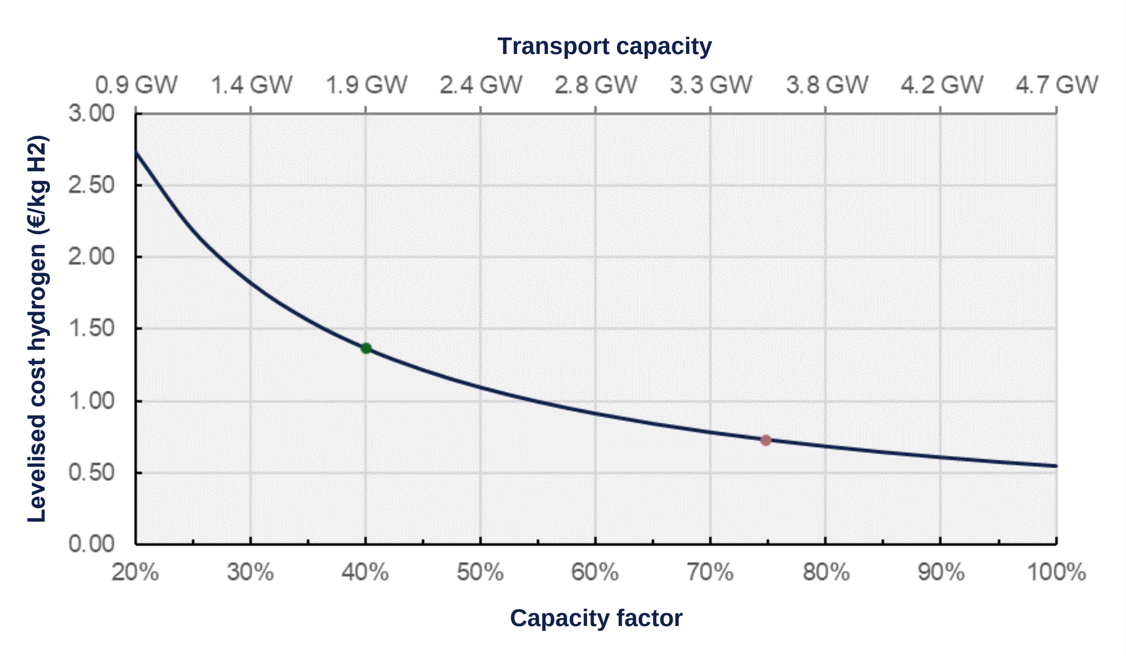
Assumptions

Calculating the levelised cost of hydrogen transport is based on the following data:

- The ‘medium’ scenario of the hydrogen transport cost estimates from the European Hydrogen Backbone report (see Appendix)
- Pipeline OPEX of 1.0% of CAPEX per year; compression OPEX of 1.7% of CAPEX per year.
- A discount rate of 10%, equal to the discount rate used in the levelized cost analysis presented earlier in this report.
- A depreciation period of 40 years for the pipelines and a depreciation period of 25 years for the compressors.

Results

- A total CAPEX cost of M€ 5,804
- At a capacity factor of 75%, the maximum transport capacity of the repurposed pipelines of 3.6 GW is met. At this point, the levelised cost of hydrogen transport will be 0.73 €/kg H2.
- At a capacity factor of 40%, the expected capacity factor from Finnish onshore wind, the levelised cost of hydrogen transport will be 1.37 €/kg H2.



Source: DNV. Green dot = capacity factor for Finnish onshore wind. Red dot = capacity factor equal to bottleneck capacity for Nordic-Baltic hydrogen corridor.

4.3 Technical aspects and cost of alternative pipeline routes

The absence of geological hydrogen storage possibilities in the countries of origin provides a challenge that, if mitigated, could increase the yearly transport capacities of the analysed routes.

Hydrogen storage and total system cost

In the previous study, the potential for hydrogen production on the North Sea was quantified. There, the total system costs were derived as a sum of the production costs, transport costs and storage costs. In this study, such an analysis would not be fruitful as the production costs are geographically dispersed whereas the calculated transport costs only consider transporting hydrogen from a specific starting point in Finland. Furthermore, regarding large scale hydrogen storage for long-term balancing the boundary conditions in the producing countries are very different from those on the North Sea, in the following aspects:

1) The absence of geological storage possibilities in the regions of origin
2) The presence of other regional sinks/sources of hydrogen which could help to buffer supply and demand
3) The simultaneity of production and consumption in different NUTS regions subject to non-homogeneous weather patterns

This makes it hard to quantify the overall storage requirement to produce a 'flat line' production profile from the region. In case of the North Sea this could be largely justified because there were only sources of hydrogen and no sinks in the region. As a rule of thumb, 30% of hydrogen produced yearly from offshore wind needs to be stored.

As a result, to balance out the production profile from Finland other means of storage must be considered, often at a significantly higher cost compared to geological storage. There exists of possibility of storing the hydrogen in salt caverns in Germany, downstream of the pipeline, but this is subject to availability. Furthermore, this option would not result in an increase of transport capacity as the buffering happens downstream of the pipeline.

Known limitations to the analysis

- The capacity factor of the hydrogen pipeline could be increased from the 40% assumed in this study by managing the simultaneity of the magnitude of hydrogen to be transported. In this study, this simultaneity is assumed to be homogeneous throughout the region of origin. A full analysis of the spatial and temporal impact of weather patterns, demand patterns and the availability of storage is not conducted.
- DNV has not conducted a complete routing study, for instance the effects of water depth on pipeline design were not explicitly included. Furthermore, existing pipeline infrastructure and required pipeline crossings were not analysed in detail to determine the route.
- The cost figures taken from the European Hydrogen Backbone report might be considered conservative (e.g. higher) for offshore pipelines compared to DNV’s analysis.

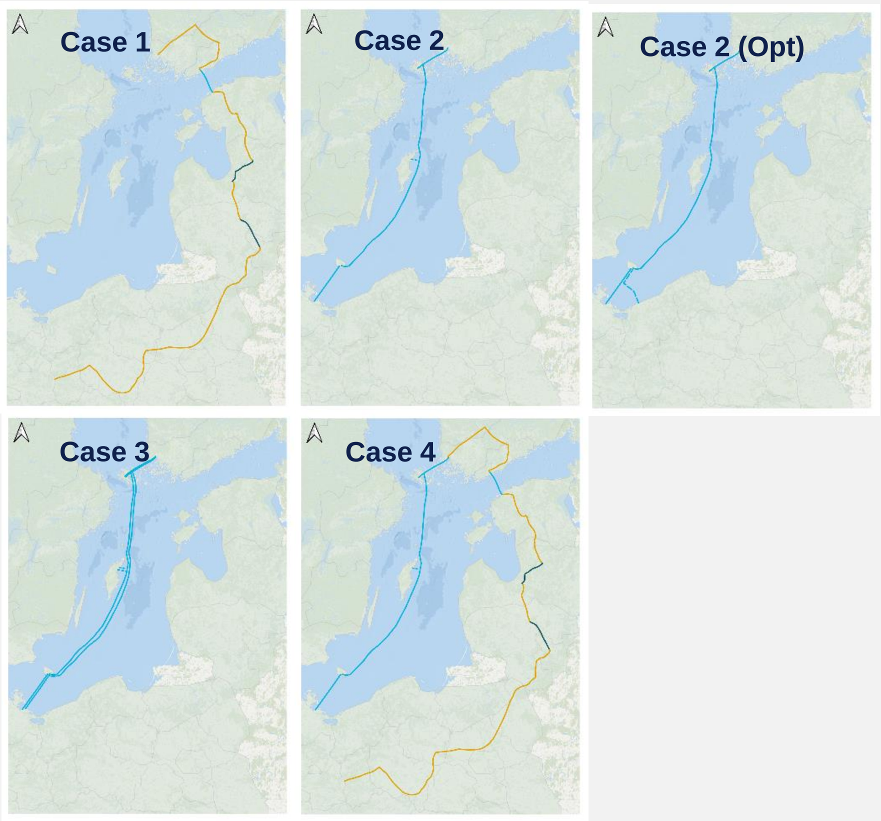
4.3 Route comparisons

The onshore pipeline route alone will not provide enough capacity to transport the surplus from Finland. A single optimised offshore pipeline provides the cheapest levelised cost of hydrogen transport (1/2).

This slide and the following slide present the results of the various pipeline route options:

- **Case 1: Onshore route only:** This route can transport 16.5 TWh of hydrogen, based on the Finnish onshore wind capacity factor of 40%, which is only sufficient to transport the 2030 surplus. The overall capex is around €5.8 billion, but at €1.37/kg, it is the most expensive option on a Levelised Cost of Hydrogen Transport basis.
- **Case 2: Offshore route – pipeline A only:** This option can transport 59.2 TWh, which is sufficient for all scenarios except for 2050 in the Optimistic Scenario. The overall capex is similar to Case 1, but the Levelised Cost of Hydrogen Transport is far cheaper, at €0.40/kg.
- **Case 2 (Opt): Offshore route – pipeline A (optimised) only:** This option can transport 65.0 TWh, which is sufficient for all analysed years in the Optimistic Scenario. The overall capex is similar to Case 2, but the Levelised Cost of Hydrogen Transport is a bit lower, at €0.39/kg.
- **Case 3: Offshore route – pipeline A and pipeline B:** The two offshore pipelines can together transport a total of 118.4 TWh, more than enough for both scenarios to 2050, at a levelised cost of €0.40/kg. The overall capex is, however, around €11.8 billion – twice as high as Case 2.
- **Case 4: Onshore route and offshore route – pipeline A:** This option can transport 75.7 TWh, which is sufficient for all analysed scenarios. The overall capex is similar to Case 3, but the weighted average levelised cost is higher, at €0.61/kg.

Overall, the cheapest option to transport all the surplus from Finland in the Optimistic Scenario would be a single capacity optimised offshore pipeline, at a levelised cost of hydrogen transport of 0.39 €/kg H2.



Source for maps: DNV, based on European Hydrogen Backbone

4.3 Route comparisons

The onshore pipeline route alone will not provide enough capacity to transport the surplus from Finland. A single optimised offshore pipeline provides the cheapest levelised cost of hydrogen transport (2/2).

		Case 1	Case 2	Case 2 Opt	Case 3	Case 4	
		Transport capacity [TWh_{H2}/yr LHV] – @Finnish onshore wind capacity factor of 40%					
Year	**Scenario**	**Onshore only**	**Offshore A only**	**Offshore A (Optimized) only**	**Offshore A + B**	**Onshore + Offshore A**	**Surplus Finland**
2030	Conservative	16.5	59.2	65.0	118.4	75.7	0.0
2040	Conservative	16.5	59.2	65.0	118.4	75.7	20.5
2050	Conservative	16.5	59.2	65.0	118.4	75.7	40.1
2030	Optimistic	16.5	59.2	65.0	118.4	75.7	5.5
2040	Optimistic	16.5	59.2	65.0	118.4	75.7	44.9
2050	Optimistic	16.5	59.2	65.0	118.4	75.7	62.4
Total CAPEX cost (M€)		5,804	5,872	6,478	11,820	11,676	
Levelised Cost of Hydrogen Transport (€/kg H2)*		1.37	0.40	0.39	0.40	0.61	

* LCOH based on a capacity factor of 40%

Redundant transport capacity

Transport capacity sufficient

Transport capacity NOT sufficient

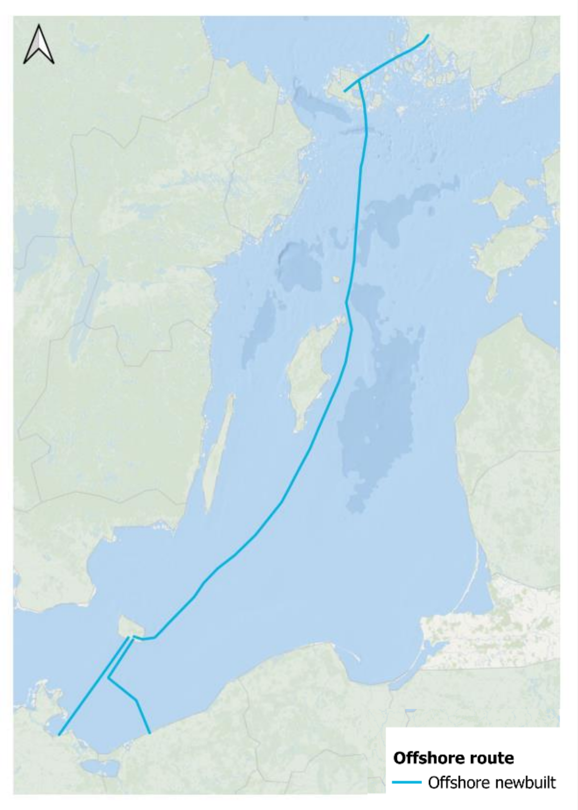
4.4 Conclusions on routings

Although offshore pipelines have around 50% higher capex than onshore pipes, the onshore route from Finland to Germany is twice as long. Combined with higher capacity, the offshore route is a more-cost effective option to transport surplus hydrogen from Finland.

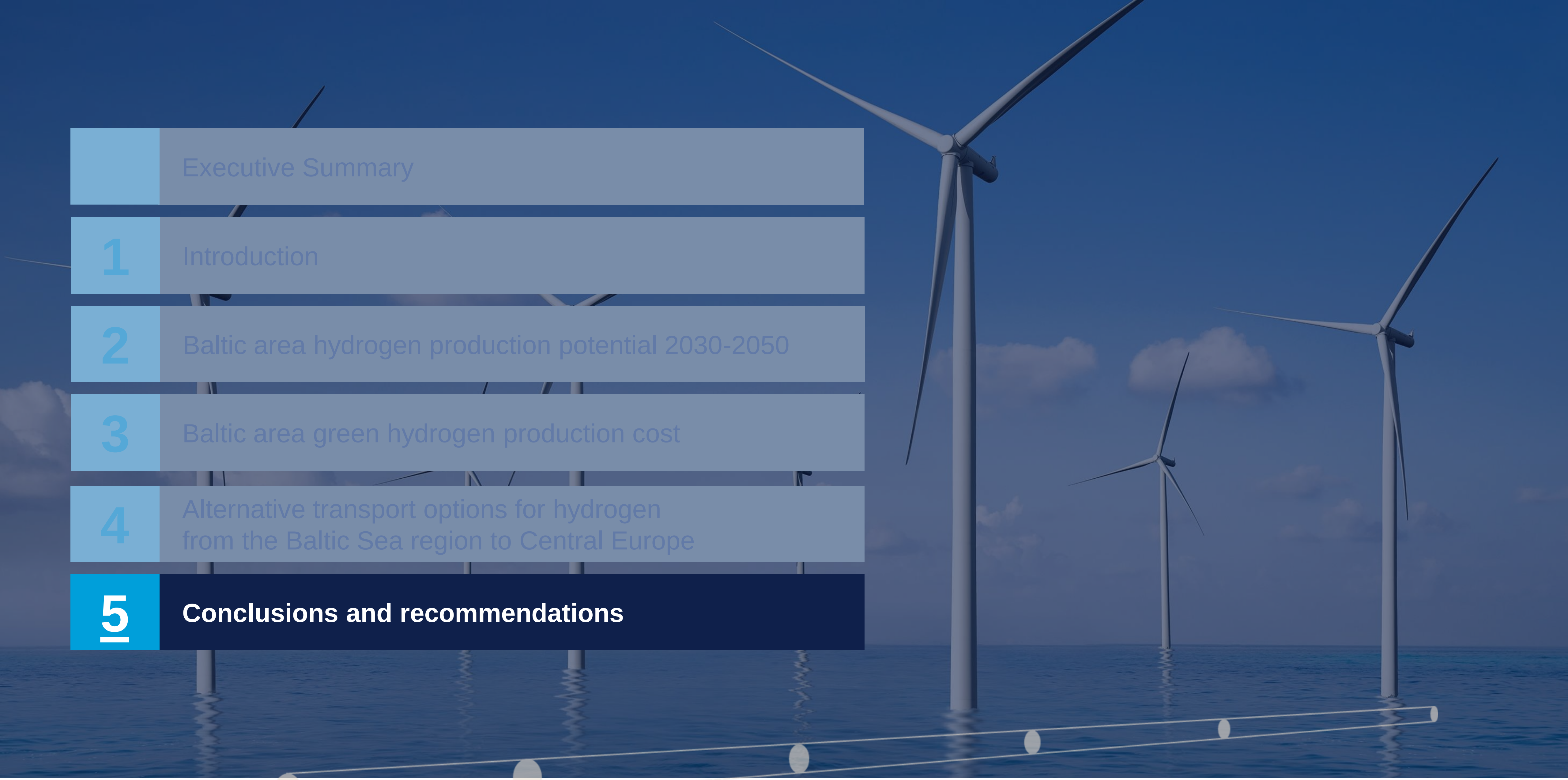
Conclusions:

- The onshore pipeline route alone is not enough to transport the expected surplus hydrogen from Finland to Germany after 2030, but it is important to transport hydrogen through the Baltic countries and to Poland, which is already one of the EU's largest hydrogen consumers.
- If, next to the **onshore route** (16.5 TWh/yr), an additional **offshore pipeline route** – consisting of a single (non-optimised) pipeline (59.2 TWh/yr) – would be constructed, this would amount to a total transport volume of 75.7 TWh/yr. This would be enough to transport the surplus hydrogen from Finland for all analysed years in the Conservative and Optimistic Scenarios. This would, however, require recompression on the island of Gotland as the default pressure of 80 bar is not enough to transport the hydrogen through the ~760 km pipeline.
- Alternatively, a **single optimised pipeline** could transport 65 TWh/yr at a pressure of 170 bar, omitting the need for recompression on the island of Gotland. This single pipeline would be enough to transport the surplus hydrogen from Finland for all analysed years in the Conservative and Optimistic Scenarios and features the lowest Levelised Cost of Hydrogen transported. Furthermore, this option ensures linking the Baltic countries to Poland.
- A **dual offshore** route, as foreseen by the European Hydrogen Backbone initiative, with a transport capacity of 118.4 TWh/yr, is less likely to be feasible if the onshore route is constructed, as it would increase the overall transport capacity to 134.9 TWh/yr. The Optimistic Scenario which we have calculated in this study envisages only 62.4 TWh of surplus hydrogen to be transported by 2050, so this pipeline option would have significant unused capacity.
- Even though offshore pipelines are approximately ~1.5 times more expensive than onshore pipelines with the same diameter, the difference in total transport distance between the onshore and offshore routes (1,000 km vs 2,000 km respectively), combined with the larger overall diameter and pressure (and hence transport capacity) across the **offshore routes** make these a **more cost-effective option** to transport surplus hydrogen from Finland to Central Europe. Overall, the following levelized transport cost can be associated to the discussed alternatives;
  - Case 1: The levelised cost of hydrogen transport through the **onshore** hydrogen route is 1.37 €/kg H2.
  - Case 2: The levelised cost of hydrogen transport through the **non-optimised offshore** hydrogen route is 0.40 €/kg H2.
  - Case 2 (opt): The levelised cost of hydrogen transport through the **optimised offshore** hydrogen route is 0.39 €/kg H2.

As a summary it can be concluded that in case the onshore route is not realized (in time), having a **single optimised pipeline** along **the offshore route would provide sufficient transport capacity in all analysed scenarios and years**. Additionally, on a Levelised Cost of Hydrogen Transport basis, this option is the most cost-effective. However, from a viewpoint of diversification and developing hydrogen production in the Baltic states, the onshore route provides additional security of supply.



Source: DNV, based on European Hydrogen Backbone



5. Summary and recommendations

Baltic hydrogen production offers opportunities to strengthen Europe's strategic hydrogen supply.

Focus of the report

- In the previous chapters we have analysed the possibilities of hydrogen production in the Scandinavian countries for export to Central Europe.
- As shown in **Chapter 2**, the existence of a surplus of renewable electricity is essential to produce hydrogen in this region for export. Chapter 1 has shown that there is a surplus potential, but that this is strongly dependent on the expansion targets for renewable energies in the Nordic countries. Furthermore, the chosen decarbonisation strategy and the progress of electrification of end use sectors in the potential exporting countries have a strong influence on the surplus potential. In addition, there must be a social consensus to make land available for renewable generation that exceeds local demand. The two scenarios presented have shown that there is considerable potential, but that a large amount of new wind energy will also have to be built to enable the export of hydrogen.
- **Chapter 3** has outlined the costs at which hydrogen can be produced in the northern Baltic Sea countries. As photovoltaics is not an economically viable source to produce green hydrogen due to the low solar irradiation in northern latitudes. Therefore, the focus of the analysis was on onshore and offshore wind. It was found that there are large differences in production conditions, such that the LCOH varies greatly depending on the location. At good locations, LCOH of around 4.5-5 euros/kg can be achieved for directly generated electricity from renewable energies, especially via offshore wind, but also in some regions via onshore wind. Depending on the region, even lower production costs can be achieved for electricity from the grid – with its portfolio effects from hydropower – so that the costs can also be considered advantageous in an international comparison as well as in comparison to the costs of offshore production in the North Sea. However, it should be noted that regulation plays a major role in grid procurement and large expansion of electrolysis capacity must always go hand in hand with a corresponding expansion of renewable energies, so that the regulatory advantage of grid procurement with its advantageous electricity cost profile is not lost
- **Chapter 4** concludes by analysing possible pipeline routings based on the regionalised surpluses. It was shown that the combination of an offshore and an onshore pipeline offers advantages in terms of diversification of supply. Nevertheless, an optimized offshore pipeline, which also could connect Poland, would be sufficient and more cost effective for the transport of the calculated 62 TWh hydrogen (Optimistic scenario, 2050) to Central Europe.

Conclusions

- The option of sourcing hydrogen from the Baltic Sea region is economically and strategically interesting for Central Europe. Low production costs coupled with intra-European production can support Europe's industrial competitiveness and would make Europe less dependent on imports.
- For many end-uses, the possibility to obtain pure hydrogen (and not derivatives like ammonia) is attractive as it is more efficient and avoids the cost of conversion processes.
- A combination of offshore and onshore pipelines can diversify the supply, as there is sufficient hydrogen generation potential, if the potential for surplus renewable electricity is realised. An optimised offshore pipeline would provide the most cost-effective means of transport to Central Europe.
- A hydrogen partnership between the countries bordering the Baltic Sea region and potential customers such as Germany and Poland presupposes that there is a social consensus in the Scandinavian countries that the expansion of renewable energies should be on a larger scale than is necessary for local demand.

Recommendations for next steps

- In this study, a first analysis of the potential of hydrogen production and possible transport to Central Europe was carried out. The study is based on assumptions from different sources and modelling.
- Furthermore, we recommend a strategic dialogue between the countries bordering the Baltic Sea and the countries of the EU that are dependent on hydrogen imports (especially Germany and Poland). The aim should be to develop a joint strategy and vision for a hydrogen network in the Baltic Sea region that develops the previous ideas in the discussions on a European hydrogen backbone and firms up the plans for RES expansion, pipeline planning and industrial use. Due to the many aspects that need to be considered, a multinational agreement for such a hydrogen production and network expansion would be necessary.

Appendix

Appendix

Abbreviations

AC – Alternating Current
AFIR – Alternative Fuels Infrastructure Regulation
ASME – American Society of Mechanical Engineers
CAPEX – Capital Expenditure
CF – Capacity Factor
CHP – Combined Heat and Power plant
DE – Distributed Energy scenario (see TYNDP)
DRI – Direct Reduction of Iron
EHB – European Hydrogen Backbone
ENTSO – European Network of Transmission System Operators
ETO – Energy Transition Outlook (DNV)
ETS – Emissions Trading System (EU)
EU – European Union
EUR – Euro (€)
FID – Final Investment Decision
GA – Global Ambitions scenario (see TYNDP)
GDP – Gross Domestic Product
GHG – Greenhouse gases
GW – Giga Watt
HDV – Heavy Duty Vehicles

HHV – Higher Heating Value
HVAC – High Voltage Alternating Current
HVDC – High Voltage Direct Current
IEA – International Energy Agency
LCOE – Levelised Cost of Energy / Electricity
LCOH – Levelised Cost of Hydrogen
LHV – Lower Heating Value
LOHC – Liquid Organic Hydrogen Carriers
LULUCF – Land Use, Land Use Change and Forestry
MJ – Mega Joule
MW – Mega Watt
NATO – North Atlantic Treaty Organization
NECP – National Energy and Climate Plans
NICPB – National Institute of Chemical Physics and Biophysics (Estonia)
NUTS – Nomenclature of Territorial Units for Statistics (EU)
OPEX – Operational Expenditure
PEM – Proton Exchange Membrane (Electrolyser)
PNZ – Pathway to Net Zero (scenario)
PPA – Power Purchase Agreement
PV – PhotoVoltaics

RED – Renewable Energy Directive
RES – Renewable Energy Sources*
RFNBO – Renewable Fuels of Non-Biological Origin
SEA – Swedish Energy Agency
SEI – Stockholm Environment Institute
TES – Total Energy Supply
TYNDP – Ten Year Network Development Plans
UNFCCC – United Nations Framework Convention on Climate Change
WACC – Weighted Average Cost of Capital

Source: DNV

* Note: Renewable Energy Sources as defined in this report include and On-and Offshore Wind, Solar PV, Hydropower, Biofuels and Other RES (incl. marine, geothermal, waste, and any other small renewable technologies which are carbon-neutral).

Appendix

Installed capacity & energy content of hydrogen (heating value) conventions

Capacity

When discussing installed capacity of energy assets, it is important to distinguish between electricity and hydrogen as the energy vectors. Therefore, we have chosen to include subscripts when discussing capacity figures, to ease the reader in understanding what is being considered.

GW_{el} – Giga Watt electrical

- Used to denote wind farm electrical output capacity and electrolyser electrical input capacity, as per conventions.

GW_{H2} – Giga Watt hydrogen

- Used to denote hydrogen pipeline transport capacity as per conventions.
- Can be used to denote electrolyser hydrogen output capacity, although this is not the convention this approach is taken in some publications. Clearly, the industry is not yet fully aligned on which approach to take.

Energy content

Furthermore, when discussing conversion efficiency and amounts of hydrogen in terms of energy content, it is important to distinguish between

Higher Heating Value (HHV) is also referred to as the gross calorific value. During combustion of hydrogen rich fuels water is released by combining hydrogen and oxygen. This subsequently evaporates which consumes some of the energy which is then not available anymore to “do work”. The Lower Heating Value (LHV), or net calorific value, corrects for this “loss” and is therefore lower. The higher and lower heating value of hydrogen are 142 and 120 MJ/kg respectively.

- ***In this report, by default the LHV is taken as a basis, as this is the default for many gas grid operators.***

Source: DNV

Appendix

Levelised cost calculation methodology – introduction

Levelised Cost of Energy

The levelised cost of energy (LCOE) is a common metric used in the energy industry to compare the cost of different sources of electricity generation. It represents the average cost of electricity over the lifetime of a power-generating asset, such as a wind turbine or solar panel. The LCOE considers the cost of building and operating the asset, as well as a discount rate to account for the time value of money. LCOE is often expressed in units of currency per unit of energy (e.g., €/MWh). By comparing the LCOE of different power sources, policymakers and investors can make informed decisions about which types of generation are the most cost-effective.

Levelised Cost of Hydrogen

The same methodology is extended to compare hydrogen value chains by including the cost of building and operating hydrogen production- and transportation assets, such as electrolysers or hydrogen pipelines. The levelised cost of hydrogen (LCOH) represents the average cost of hydrogen over the lifetime of the full value chain. It is often expressed in units of currency per unit mass of hydrogen (e.g., €/kg H_2). This unit is preferred, since on an energetic basis (€/MWh) it is not explicit whether the lower heating value (LHV) or higher heating value (HHV) of hydrogen is taken as a basis.

- *In this report, by default the LHV is taken as a basis, as this is the default for many gas grid operators.*

Discount rates

A discount rate is a method used to account for the time value of money in financial analysis. It is the rate at which future cash flows are discounted to their present value. In other words, it is the rate at which future costs and benefits are "discounted" to reflect their relative value in the present.

The discount rate is an important factor in determining the economic feasibility of a project or investment. A higher discount rate will lead to a lower present value for future cash flows, making a project appear less valuable. Conversely, a lower discount rate will lead to a higher present value, making a project appear more valuable.

Source: DNV

Appendix

Levelised cost calculation – general assumptions (as used in chapter 3.3)

General assumptions

- All costs are reported as unit costs and are modelled to scale linearly with capacity (economies of scale effects are neglected)
- Energy price data is extracted from the DNV Energy Transition Outlook and is assumed to be valid for the Europe region. Based on this, power prices and levelised cost of renewable energy technologies are expected to reduce from 2030 through to 2050.
- Learning rates are made explicit by providing cost figures for the years 2030, 2040 and 2050 based on ETO data and DNV expert judgement.

Topology assumptions

- Direct renewables
  - Onshore hydrogen production is assumed to be co-located with the energy source, there are therefore no energy transmission costs involved for transporting electricity from the energy source to the electrolyser.
  - For offshore wind to hydrogen, the battery limit of the model has been assumed to be the onshore electrolyser or the pipeline landfall.
  - For offshore hydrogen production, only the decentralised hydrogen production topology with an offshore hydrogen production platform is considered.
  - For all these cases, renewable generation capacity and electrolysis capacity are assumed to be equal.
- Grid-based
  - Grid based electrolysis is only considered to be part of this analysis if 90% of the respective countries' energy supply is renewable, as per REDII.
  - In this case, the yearly average forecasted grid prices are taken as a basis for the LCOE input.

Electrolysis assumptions

- Electrolyser capacity is defined per electrical input capacity (MW_{el}).
- Electrolyser topology is chosen as PEM, due to ability to cope with intermittent sources.
- Electrolyser costs are reported as unit costs per building block of 100 MW_{el} electrolyser capacity, and modelled to scale linearly with this capacity. This, because DNV experts deem that after 100 MW_{el} the economies of scale effects for electrolysers have flattened out.
- Electrolyser costs include stacks, balance of plant (electrical systems such as medium voltage transformers and rectifiers, a safety & control system and cables, as well as gas systems such as pipes, pumps, heat exchangers, liquid/gas separators, dryers, and gas purification and treatment equipment), water treatment and subsequent hydrogen compression from 30 to 80 bar.
- Installing and operating electrolysers offshore is expected to be more costly than their onshore counterparts, this is reflected in the cost figures for the offshore cases.
- Electrolyser CAPEX is assumed to reduce and efficiency to increase over the years from 2030 through to 2050, based on DNV expert analysis.

Economic modelling

- Nominal discount rate (WACC) has been assumed to be 10%
- Project lifecycle has been assumed to be 20 years
- Calculated costs are only direct costs and don't include indirect costs such as financing and contingency.

Annex: Overview of sources used in the optimistic and conservative scenarios per country

<table>
<tr><th rowspan="2">Scenario parameters</th><th colspan="2">Sweden</th><th colspan="2">Finland</th><th colspan="2">Latvia</th><th colspan="2">Estonia</th><th colspan="2">Lithuania</th><th colspan="2">Poland</th></tr>
<tr><th>Optimistic</th><th>Conservative</th><th>Optimistic</th><th>Conservative</th><th>Optimistic</th><th>Conservative</th><th>Optimistic</th><th>Conservative</th><th>Optimistic</th><th>Conservative</th><th>Optimistic</th><th>Conservative</th></tr>
<tr><td>Electricity Supply</td><td rowspan="2">Swedish Energy Agency 2023; ‘High Electrification’ scenario</td><td rowspan="2">Swedish Energy Agency 2023; ‘Low Electrification’ scenario</td><td rowspan="2">TYNDP22 Distributed Energy scenario</td><td rowspan="2">TYNDP22 Global Ambition scenario</td><td rowspan="3">TYNDP22 Distributed Energy scenario</td><td rowspan="3">TYNDP22 Global Ambition scenario</td><td colspan="2">Transitioning to a climate-neutral electricity generation</td><td rowspan="3">TYNDP22 Distributed Energy scenario</td><td rowspan="3">TYNDP22 Global Ambition scenario</td><td rowspan="3">TYNDP22 Distributed Energy scenario</td><td rowspan="3">TYNDP22 Global Ambition scenario</td></tr>
<tr><td>Electricity demand excl. domestic H2</td><td>TYNDP22 Distributed Energy scenario</td><td rowspan="2">TYNDP22 Global Ambition scenario</td></tr>
<tr><td>Electricity demand domestic H2</td><td colspan="2">TYNDP22 Distributed Energy scenario</td><td>Finnish Government Analysis – Maximum B</td><td>Finnish Government Analysis – No regret B</td><td>Analysis of the hydrogen resources usage in Estonia</td></tr>
<tr><td>RES target</td><td colspan="2">2030 & 2040: RES-E target set by Swedish government.
2050: Assumption – RES generation target constant</td><td>2030: RES-E target set by the Finnish government.
2040 & 2050: General emission reduction targets.</td><td>2030: RES-E target set by the Finnish government.
2040 & 2050: General emission reduction targets.</td><td colspan="2">RES-E target set by the Latvian government in its draft updated NECP.</td><td colspan="2">RES-E target set by the Estonian government in its draft updated NECP.</td><td colspan="2">RES-E target set by the Lithuanian government in its draft updated NECP.</td><td>2030: Upper RES-E target (NECP).
2040 & 2050: GHG emission reduction target; scenario ‘with additional measures’</td><td>2030: Lower RES-E target (NECP).
2040 & 2050: GHG emission reduction target; scenario ‘with existing measures’</td></tr>
</table>

Annex: Regionalization of Hydrogen Demand on NUTS-level

Factors used to allocate national hydrogen demand to NUTS-regions

Note:

- Latvia and Estonia are not represented here as our analysis does not go further down than the NUTS2 level which equals the national level in the case of Latvia and Estonia.
- Statistical factors used were available on NUTS level.

Hydrogen demand sector	Sweden	Finland	Lithuania	Poland
Industry	Non-energy use & Process Heat: Gross value added of the industrial sector (MEUR) (Eurostat)	Iron & Steel: Location of the main steel plant expected to use hydrogen (Northern Finland) Biofuel production: Energy use in industry distribution (GWh) (FI statistics office) Refineries: Current refinery locations (Southern Finland)	Equal distribution between capital region and western region based on equal distribution of entities with at least one person employed in the manufacturing sector.	Consumption of fuels and energy carriers (Polish statistics office)
Mobility	Road Transport: Freight transport (million tonne-km) (Eurostat) Rail: Population distribution (Eurostat) Aviation: Aviation freight (tonne) and passengers carried (Eurostat) Shipping: Harbour freight (tonne) and passengers carried (Eurostat)	Road Transport: Road traffic performance (mln. km) (FI statistics office) Shipping: Shipping cargo (tons)	Road Transport: Freight transport (million tonne-km) (Eurostat) Rail: Population distribution (Eurostat) Aviation: Aviation freight (tonne) and passengers carried (Eurostat) Shipping: 100% allocation to Western Region (LT02) which is the only one bordering the sea.	Road Transport: Freight transport (million tonne-km) (Eurostat) Rail: Transported passengers (Polish Statistical Office) Aviation: Aviation freight (tonne) and passengers carried (Eurostat) Shipping: Harbour freight (tonne) and passengers carried (Eurostat)
Other demand	Residential & Tertiary: Population distribution (Eurostat)	Equal distribution between NUTS region	Residential & Tertiary: Population distribution (Eurostat)	Residential & Tertiary: Population distribution (Eurostat)

Annex: Steps for Regionalized Surplus Estimation

Breakdown of national surplus calculation into NUTS2 – regions

Analysis of all known current and upcoming RES sites (Onshore and Offshore Wind & PV), allocation to respective NUTS2 – regions (installed capacity)

Renewables production by NUTS2-region adjusted to the overall national target

Balancing between the NUTS2-regions (preferably by neighbouring regions). Rational: national/local demand has priority over export

Allocation of Renewables according to Database

Application of regional capacity factors

Scaling according to National Targets

Regional RES-production corrected to pot. surplus

Regional Balancing

Adjustment of regional surplus to National targets

Application of regionalized capacity factor for each of the RES-types

Deduction of share for overall national renewables target and local hydrogen demand from overall renewables production

Adjustment according to the national targets for respective scenario to have congruency on national and regional level.

Annex: Overview of cost estimates for hydrogen pipelines as per the ‘medium’ scenario of the European Hydrogen Backbone reports

Type		Diameter (inch)	Capacity (GW)	Pipeline CAPEX (M€/km)	Compression CAPEX (M€/km)	Operating pressure (bar)
Onshore Small	New	20	1.2	1.5	0.09	50
	Repurposed	20	1.2	0.3	0.09	50
Onshore Medium	New	36	4.7	2.2	0.32	50
	Repurposed	36	3.6	0.4	0.14	50
Onshore Large	New	48	16.9	2.8	0.62	80
	Repurposed	48	12.7	0.5	0.62	80
Offshore Medium	New	36	4.7	3.7	0.54	50
	Repurposed	36	3.6	0.4	0.23	50
Offshore Large	New	48	16.9	4.8	1.06	80
	Repurposed	48	12.7	0.5	1.06	80

Note: These figures are taken from the European Hydrogen Backbone 2021 report, benchmarking with DNV’s pipeline dimensioning tools have shown that the values for offshore hydrogen pipelines might be considered conservative (e.g. higher than the benchmark). In November 2023, the EHB has released their report “Implementation roadmap - Cross border projects and costs update”. This has shown an 20% - 200% increase (average +45%) from 2021 to 2023, which can mainly be attributed to inflation according to the authors. During the execution of this project, these new cost figures were not yet available, and therefore the cost figures from 2021 were used as reference.

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