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# Carbon Negative Åland
# STRATEGIC ROADMAP

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# Content

# Executive Summary


The focus of this study was to analyze offshore wind power's future options and maximum value creation for Åland, covering the most feasible solutions for exporting of green electricity, feasibility of hydrogen production and transmission, alternative strategies, and steps for developing offshore wind-based business in Åland, as well as assessment of risk and opportunities and propose next steps for Åland with offshore wind. Beside this study, a review of existing offshore wind power was made as a master's thesis.

The large wind farm areas F4 and F6 in the northern side of Åland with capacity of about 4 GW and annual generation of 20 TWh turned out to be the most feasible when considering transmission of electricity. Åland wind farms locate in the area, where the farm connection could provide possible basis for interconnection of two power systems, too. The additional cost for a solution where energy transmission from wind farm could be done to both Finland and Sweden is approximately +5 €/MWh compared to the solution where wind capacity is realized only to one direction.

The green hydrogen potential for the region is about 18 TWh (12 TWh North, 6 TWh South). For reference, Finland's annual natural gas consumption is about 24 TWh. Hydrogen production at sea and pipeline transmission to continental Finland is estimated to be about 20% cheaper compared with alternative case based on electricity transmission to continent and conversion to hydrogen onshore. Comparing the electricity and hydrogen as products, electricity creates less interdependencies because the available grid offers access to electricity market. However, in the beginning, transmission of hydrogen is tied to one-to-one connections, which makes parties dependent on each other's. Identification of potential hydrogen customers and applications is necessary for successful implementation.

The proposed road map is to finish preliminary studies and go into development of wind farm in the area F6. During the development of the windfarm, uncertainties related to market for electricity, hydrogen and P2X products, as well as regulation for hydrogen and P2X, will decrease.



Key words: offshore wind power, transmission of electricity, green hydrogen production, transmission of hydrogen, Åland

# 1 Introduction

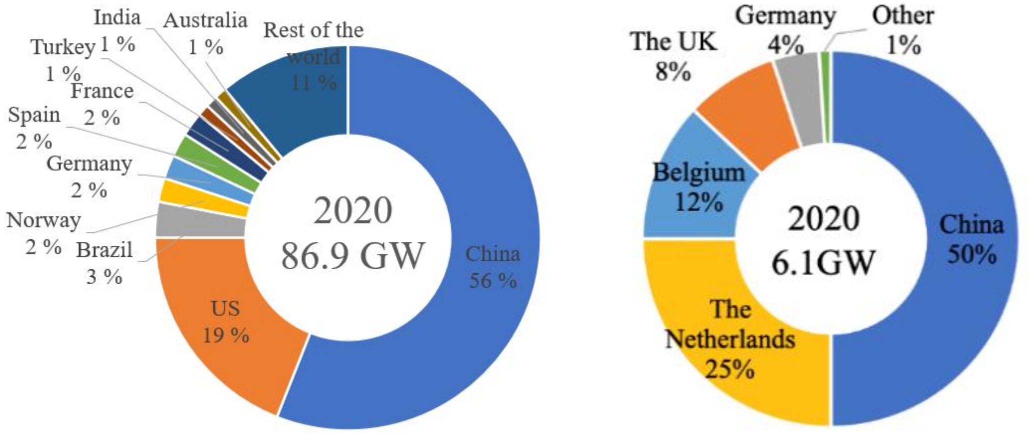
During the development of the Åland maritime spatial plan, areas suited for energy production were identified. Analyzing the potential of these areas is driven by major global and regional developments.

***Climate change*** is the key driver for finding emission free solutions for transforming the global energy system. Global temperature rise is a major concern world-wide, and vast majority of countries, almost 200, have committed to the Paris agreement, aiming to limit the harmful rise of temperature to below 1.5 °C, compared to pre-industrial level. (United Nations 2016)

***Energy system transition*** aims for emission free energy production. The most important sources for emission free and economically feasible energy are solar and wind. According to the International Energy Agency (IEA), solar power has reached a cost level (levelized cost of energy, LCOE) to be lowest in history. The average production cost of utility scale PV-plants has decreased to be between 20-40 USD/MWh in China and India, while being in the range of 30-60 USD/MWh in Europe. (Evans, 2020)

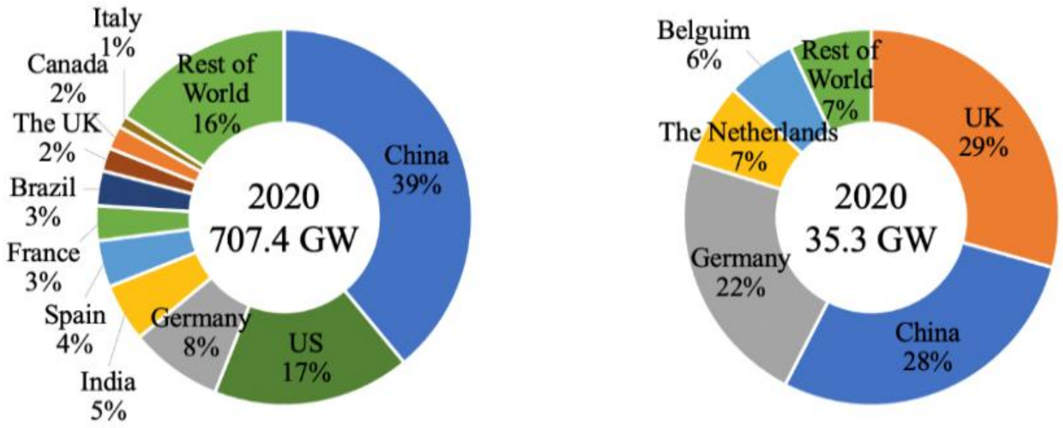
***Wind power*** is the most important renewable source in the northern regions of the world, where annual solar radiation is less than 50% of that available at the so called solar belt. This pertains especially to the Nordic countries in Fennoscandia. Globally onshore wind represents the majority of all installations, with an average LCOE of 39 USD/MWh by 2020 (IRENA, 2021). Onshore wind power has gained a strong position and competitive energy production cost due to long term technology development and market expansion, which has been ongoing strongly almost for two decades. Offshore wind installations are more demanding due to many technical challenges, e.g. seabed foundations, harsh sea environment, long underwater power transmission requirements and demanding maintenance conditions. The offshore wind market has been developing slower in the shadow of the strong onshore wind power market.

Recent years have shown increasing activities in offshore wind market. One factor is that wind conditions at sea are better compared with inland sites. In 2020, 86.9 GW of new onshore and 6.1 GW of offshore wind power was installed mainly in Europe and China, as can be seen in Figure 1.1 (GWEK, 2021; Kovalchuk, 2021). Figure 1.2 shows the total capacity of onshore and offshore wind power installations in 2020. Total capacity of onshore wind power was 707.4 GW and offshore wind power 35.5 GW.




a) b)

Figure 1.1. New a) onshore and b) offshore wind installations by country in 2020 (GWEK, 2021; Kovalchuk, 2021).




a) b)

Figure 1.2. Total wind installations a) onshore and b) offshore by country in 2020 (Kovalchuk 2021).

The ten largest offshore wind farms with their capacity are presented in Figure 1.3. They represent 20% of the total installed offshore capacity (end of 2020)

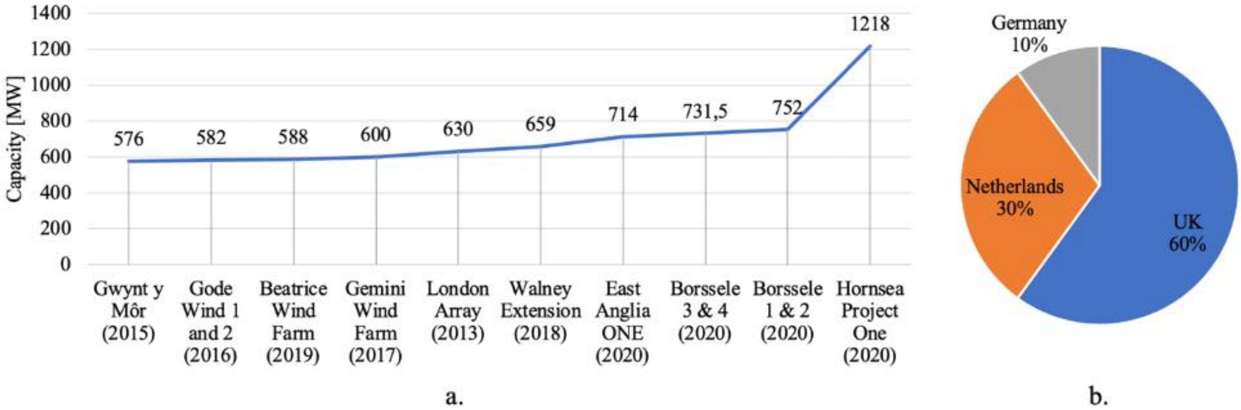



Figure 1.3. a) The 10 largest operational offshore wind farms (in spring 2021) and b) their share by country (Kovalchuk, 2021).

Turbine development has increased the current maximum power to over 10 MW, utilizing very large turbine constructions offering improved power production capacity. For example, the currently largest offshore wind farm project in Dogger Bank applies GE Haliade turbines with nominal power of 12 MW (GE, 2019). The large turbines, coupled with high full load hours, are bringing the LCOE of offshore wind power down. At the same time the interest for offshore wind is increasing due to lack of suitable and available land areas for large turbines in many densely populated countries. According to the International Renewable Energy Agency (IRENA), the globally weighted average LCOE in 2020 for offshore wind was 84 USD/MWh, more than double that of onshore wind. While offshore wind in general does not seem to be competitive compared with onshore wind power today, the offshore market is expected to accelerate strongly this decade. The installed base for offshore wind is expected to grow tenfold by 2030 compared with 2018 level, reaching 230 GW and ending up to 1000 GW by 2050. This would mean a "hockey-stick" effect in offshore wind installations, similar to what was seen in onshore about then years ago. (IRENA, 2019) It can be noted that the recent EU target for offshore wind power capacity by 2030 is 60 GW, and 300 GW by 2050. These targets are ambitious increases from the current level of 12 GW installed capacity (end of 2020). (European Commission, 2021c)

***Large scale integration of renewable power*** is one of the major issues in the on-going energy transition. Battery technology can serve as a short-term storage for renewable power, but thermal and chemical conversions are the only feasible solution, when large scale storage is needed for longer periods of time to secure the supply to the market, when the production of the intermittent weather-dependent supply is low. ***Power-to-X*** refers to technologies, where electric energy is converted to hydrogen or further to different hydrocarbons or ammonia to be used as fuels, raw materials or even proteins. ***Green hydrogen*** is defined as hydrogen produced using renewable power and water electrolysis, versus current hydrogen production that is primarily based on fossil sources. Germany has been one of the frontrunners in energy transition (Energie Wende) and has introduced a national hydrogen strategy in 2021. It includes 7 billion euros of public support for hydrogen technology development and market ramp-up as well as 2 billion for establishing international partnerships. One aim is to replace industrial use of fossil hydrogen by green one, the main scope to be steel and chemical engineering as well as fertilizer and brewery industry and certain fields of transportation. It is estimated, that by 2030 about 100 TWh of industrial hydrogen is needed in Germany, of which 14 TWh should be green hydrogen. For that, 5 GW offshore and onshore power generation corresponding 20 TWh annual power generation needs to be build. The German government has stated, that "*it will not be possible to produce large quantities of hydrogen that probably needed for the energy transition in Germany, since renewable generation within Germany are limited. Germany will therefore have to remain a major energy importer in the future. This is why we will establish and intensify international cooperation and partnerships around the topic of hydrogen.*" (Federal Government, 2020) This initiative will provide business and cooperation possibilities also for countries around the Baltic see, among others to Finland.

The opportunities offered by Power-to-X has been recognized not only in Germany, but in many other countries as well. However, Power-to-X and the hydrogen economy still has political and economic constrains, which must be overcome, before the expected decarbonization really takes place. On the other hand, several governments have included green hydrogen as part of their pandemic recovery plans in 2020. There are several technological fields, where green hydrogen can be deployed as replacement for fossil energy or row materials. (GWEC 2021)

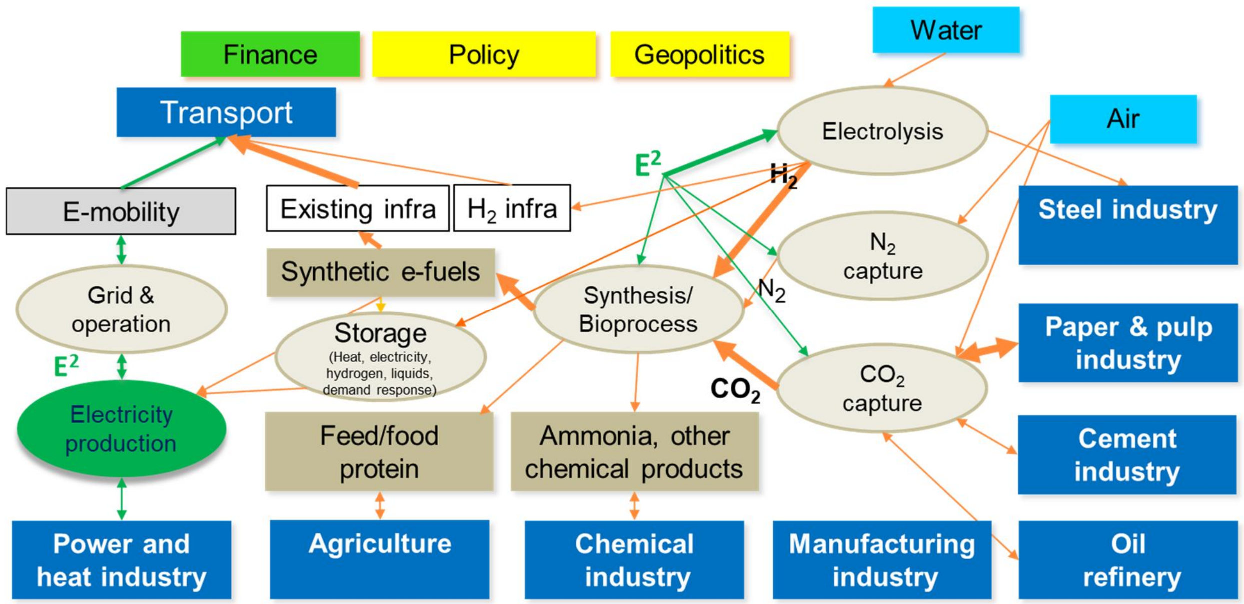



Figure 1.4. Different pathways and drivers for Power-to-X technology (Partanen).

The electrification of end-use economy is a common understanding of the future energy system. While generation costs of renewable energy sources indicate fast cost decline, the system costs – mainly related to power transmission and energy storages – will increase due to timely uncontrollable and intermittent character of both wind and solar power generation. Due to that, different opinions and future scenarios are created by the energy research community. For example, Bloomberg has given three alternative paths towards carbon neutral energy system by 2050. In the ***green scenario,*** most of the electric energy (84 %) originates from wind and solar and extensive use of renewable hydrogen increases demand of electricity dramatically to 121 549 TWh compared with 2020 level of 26597 TWh (Enerdata, 2021). The ***Grey scenario*** is based on a combination of fossil fuels and renewables, where carbon capture and storage (CCS) is used to decarbonize fossil energy sources.

In the grey scenario, hydrogen is not seen as a major energy carrier, which leads to a smaller annual power generation (62 185 TWh). The ***Red scenario*** assumes large utilization of modular nuclear power (56%) combined with renewable energy sources (44%). Since red hydrogen (hydrogen produced by nuclear power and water electrolysis) is assumed to be again a major energy carrier, the total electricity generation (96 417 TWh) is clearly higher than in grey scenario, but lower than in green scenario. It is not clear, which pathway will be dominant during the coming years. As stated by Bloomberg, "*we will probably see a mix of these solutions as each country pursues climate strategies that best suit them, considering their existing domestic economy, international trade and geopolitics*." (BloombergNEF, 2021)

Even though different scenarios have been presented, in all the cases investments in renewable power are expected to continue strong during the decades to come. It can also be assumed, that larger offshore turbines will bring the offshore wind LCOE down, which will further accelerate the offshore wind power market. The future of the hydrogen economy and power sector renewal is uncertain, which makes it important to analyze different options, when energy strategies are designed.

# 2 Focus of the study

The Åland sea areas identified in the maritime spatial plan offer a remarkable opportunity to build offshore wind power and business. However, it is not clear, what the best strategy to deploy this large renewable capacity is. Many elements need to be considered simultaneously related to technological development, general energy market development and various risks. Also timing and project design options are important aspects to analyze when decisions about energy investments and market entry are considered.

This study focuses on future options for offshore wind power in Åland's sea areas. The main questions in the study are:

- Techno-economic conditions and alternatives for large scale offshore wind power production
- Feasibility and different options for green hydrogen production
- Alternative strategies and steps for developing offshore wind-based business in Åland
- Opportunities and risks assessment and recommended next steps for Åland offshore wind development

Beside the strategic roadmap, a review of offshore wind power was conducted as a master's thesis. The techno-economic review of offshore wind power, by Viktor Kovalchuk, can be found in https://lutpub.lut.fi/handle/10024/162969.

# 3 Case Åland Description

In the Åland maritime spatial plan (adapted 18.3.2021), possibly suitable areas for large scale offshore wind production were mapped. The areas are located in the northern and southern side of Åland, as can be seen in Figure 3.1. The overall area is about 1000 km$^2$. The sizes of the different areas are shown in Table 3.1. The locations are directional, and more exact locations require additional investigations. The areas were identified by setting various criteria; maximum depth is 70 m, being outside conservation areas, sea lanes, and not impacting important recreation and tourist areas. The areas also lack documented culturally valuable objects, such as shipwrecks. The overall size of the two northern areas is 674 km$^2$ and for the southern areas about 333 km$^2$. (Ålands landskapsregering, 2021).

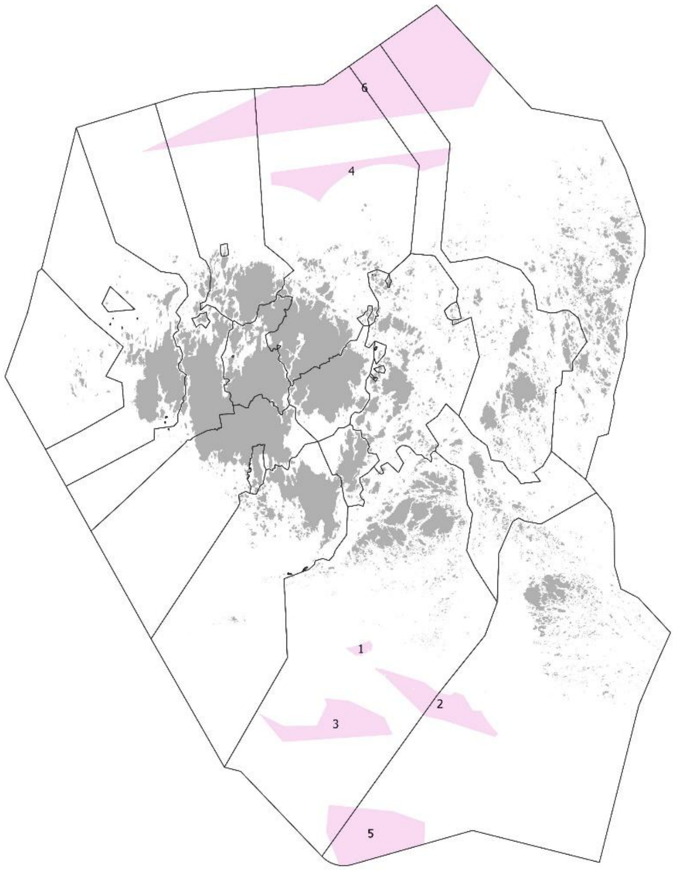



Figure 3.1. Potential wind farm areas considered in the study (Ålands landskapsregering, 2021).

Table 3.1. Sizes of potential wind farm areas considered in the study (from Ålands landskapsregering).

| **Farm** | **Size, km$^2$** |
|---|---|
| **F1** | 7.2 |
| **F2** | 85.6 |
| **F3** | 95.3 |
| **F4** | 95.8 |
| **F5** | 144.7 |
| **F6** | 579.4 |

# 4 Wind Power Production

The wind production potential was estimated based on the wind farm areas presented in Chapter 3, by assuming a filling ratio of 0.5 turbines / $km^2$, as well as a unit size of 12 MW for the turbines. The estimation was made by using General Electric Haliade-X turbines, for which the annual gross production can reach 67 GWh/a (GE 2020). After losses, production is estimated to be 61 GWh/a. Table 4.1 presents the number of turbine units, the theoretical peak power, and annual production of each studied farm.

Table 4.1. Estimated wind production potential in the studied area.

| Farm | Area ($km^2$) | Number of units | Theoretical Peak power (MW) | Annual Production (GWh) |
|---|---|---|---|---|
| **F1** | 7.2 | 4 | 48 | 244 |
| **F2** | 85.6 | 43 | 516 | 2 622 |
| **F3** | 95.3 | 48 | 576 | 2 927 |
| **F4** | 95.8 | 48 | 576 | 2 927 |
| **F5** | 144.6 | 73 | 876 | 4 451 |
| **F6** | 579.4 | 292 | 3 504 | 17 803 |
| **Total** | **1 008** | **508** | **6 096** | **30 973** |

The results were cross-checked against Renewables Ninja internet service and found to be well in line with each other (58.0% capacity factor from own analysis and 58.2% from the internet service) (Renewable Ninja). The parameters used to obtain the results from the internet service are different, especially the turbine power rating, see Appendix A. For the purposes of data validation, the potential error was not considered to be significant. All of the farms were assumed to have identical wind generation potential. The annual production shown in Table 4.1, however, highlights the significant development potential of the areas. The currently largest windfarm of Hornsea One has an estimated production of 3,8 TWh (Ørsted, 2019). Naturally, in detailed production studies conducted during the next steps, the potential should be determined in detail (based on actual wind speed measurements, preliminary turbine selection, etc.).

## 4.1 Transmission of Electricity

In this chapter, the results of the main interconnection alternatives for the identified wind farms are presented. The target is to define the most feasible solutions in terms of the levelized cost of energy to connect the wind farms to the Nordic transmission network. The results naturally indicate that the location and the size of the farms have a significant effect on the cost of energy transmission. The study takes advantage of several references, with focus on offshore wind network connection. These sources indicate the costs of the network (components and installation) in similar conditions (distances, sizes of wind farms and depth of sea) as the Åland environment.

In the study the total number of turbines is over 500 pcs and the total nominal power 6 GW. Using estimated full load hours of approximately 5100 h/a (= 58%), they would produce approximately 30 TWh energy per year as presented in Table 4.1. In Figure 4.1, the location of wind farms, their sizes and indicative distances are presented. The northern part forms approximately 4 GW of generation capacity and the southern part approximately 2 GW of generation capacity. Due to the high generation capacity compared with the relatively low present electricity demand in Åland island, the existing infrastructure has been neglected in the study and all interconnection alternatives are based on new infrastructure. Most of the network (cables) presented in different connection alternatives are planned to be of a subsea (submarine) type. <u>The wind turbine costs (platform and wind turbine) are excluded from all numbers in this chapter.</u>

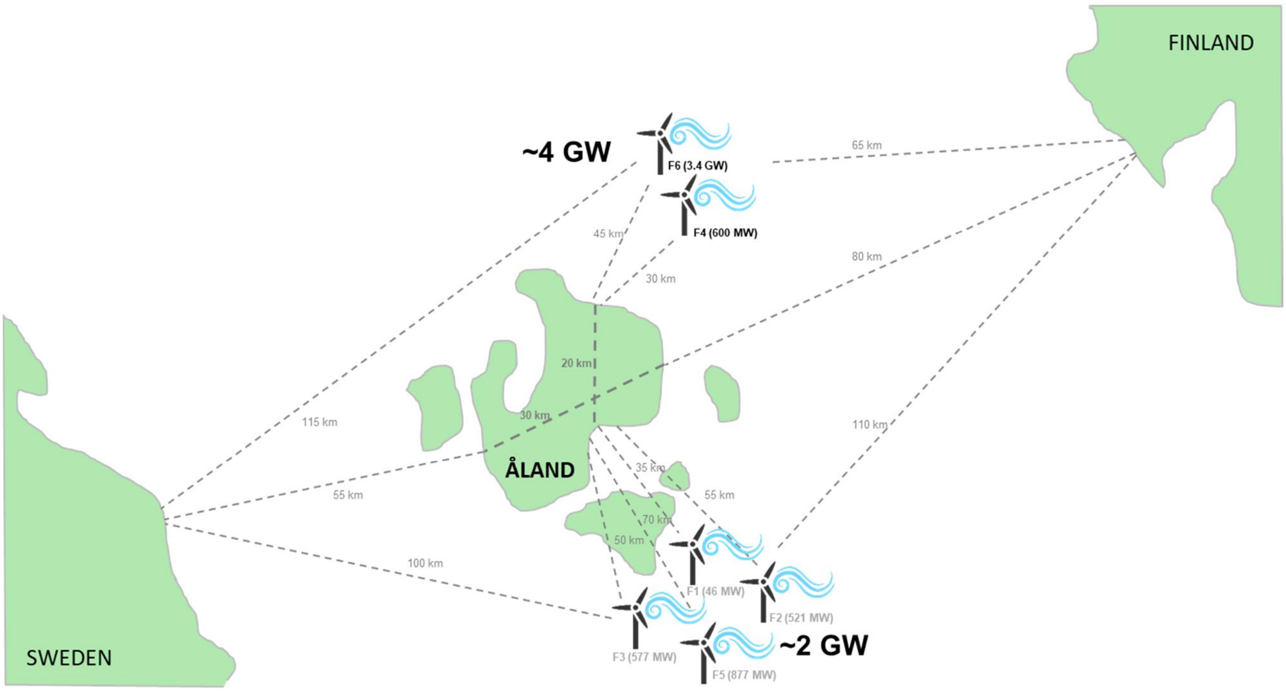



Figure 4.1. Illustration of principles of main connection alternatives and indicative distances from wind farms (F1 to F6) to Åland and continent.

The target of the network analyses is to define interconnection solutions that provide minimum lifetime costs. This corresponds to the minimized sum of investments (such as cables and substations), operational costs (such as losses and maintenance) and outage costs (Lakervi and Holmes, 1995). Reaching the lowest unit price, for instance for a cable, does not guarantee the lowest lifetime cost, for example due to higher losses or lower reliability of that cable. Due to the nature of the study, the analyses are conducted on strategic level. The connection and network solutions of individual turbines and offshore substations are not planned in detail, nor is route planning. In the study, several assumptions are made in the analyses. The most relevant are listed below.

1. Wind farms, wind turbines and wind conditions
    - All wind farms are equal regarding wind conditions (the same full load hours and the same generation profile).
2. Network and components
    - The capacity of the network is dimensioned based on maximum nominal power of wind turbines and wind farms.
    - Selection of interconnection technology (HVAC vs. HVDC) from offshore substation to continent/island has been done based on economic feasibility
    - In HVDC solutions, it is assumed that the converters can be utilized modularly so that the efficiency can be kept on a high level throughout the year
3. Platforms
    - Wind farms are symmetric so that the same amount of individual wind turbines form a unit which is connected to the offshore substation and platform. Despite possible small islands nearby the wind farms, all the installation and component costs are assumed to be subsea installations.
    - Installation depths vary from one wind farm to another and within wind farms. It is assumed that in all cases, the sea depth for the platforms is 60 m at maximum. This is due to the practical depth limit for the bottom-fixed solutions.
4. Power system (TSO)
    - The assumption is that all wind farms (power capacity) can be connected to a power system (Finland or Sweden or both)
    - Interconnection costs defined in the study do not include possible system level costs in the power system. In the report, high voltage export cables from the wind farm substation to the continent (TSO) are defined with the shortest distance.
5. Analyses overall
    - Reliability (and outage costs) of the turbines and the electricity network have not been considered from the perspective of cost of electricity not delivered due to interruption (only included in maintenance costs).

### 4.1.1 Optimization of network connection / Principles in the analyses

The wind farm interconnection consists of several network parts. The network section closest to the wind turbines is called collector network, which is formed by array cables (MV, medium voltage subsea cables) and offshore substations. Due to the high turbine powers (>10 MW), voltage levels used in the collector network are relatively high, in the study 66 kV. In Figure 4.2, an example of a wind farm and a collector network is presented.

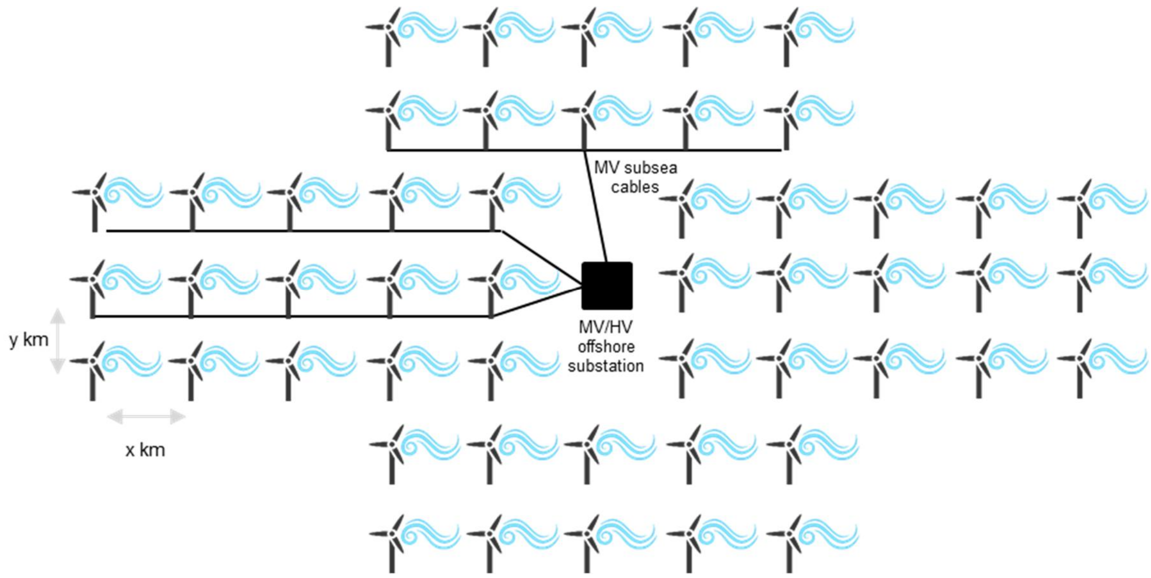



Figure 4.2. Illustration of collector network of wind farm. MV = medium-voltage, HV = high-voltage.

The number of wind turbines connected to one subsea cable and to one offshore substation, as well as distances between wind turbines, depends on the size (MW) and the height (m) of a turbine, the voltage level in a collector network and topology. On the other hand, the optimal topology of the collector network (string clustering, star clustering, mixed string/star clustering) depends on several factors such as a unit price of network components, the price of losses (electricity), installation and maintenance costs, fault frequency of components and outage costs. There are several research papers where optimization of a collector network has been studied (for example Thyssen, 2015; Shin, Kim, 2017; Serrano González, Burgos Payán, Riquelme Santos, 2013). In this study, the unit cost values of the collector network (per generation capacity and per annual generation, €/MW and €/MWh) are based on the actual installation cases built mostly in Europe.

When a wind farm consists of several offshore substations, generated electricity is transmitted first to an offshore export substation (Figure 4.3). This offshore substation collects generated power from MV/HV substations and step the voltage level to the high voltage (for instance from 110 kV to 400 kV). From the offshore export substation, the energy is transmitted to the continent power system (TSO network). The number of these connections depends on the size of the wind farm and the distances from the farm to the power system.

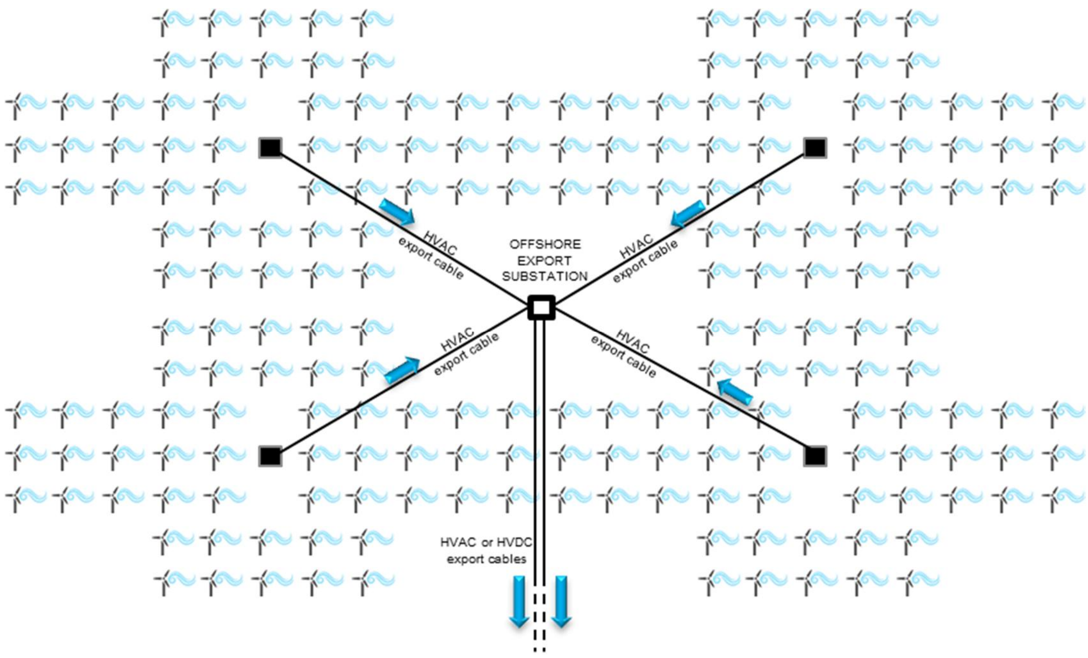



Figure 4.3. Illustration of offshore export substation and export cable network, HVAC = high-voltage AC, HVDC = high-voltage DC.

In this study, the feasible transmission technology depends on the distances and the powers related to the identified case areas. In Figure 4.4, the principles of HVAC and HVDC technologies in a wind farm interconnection are presented. In the cases where the powers and the distances are feasible for HVDC technology, voltage is converted from HVAC to HVDC in (Alternative A in the Figure4.4).

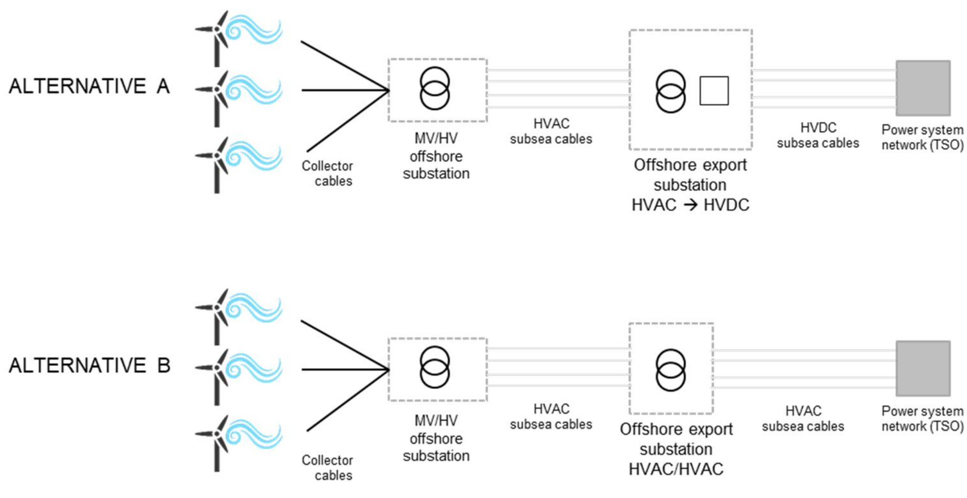



Figure 4.4. Principles of technological solutions. Alternative A) High voltage DC (HVDC) connection, and B) High voltage AC (HVAC) connection from wind farm to power system.

The optimization of a wind farm structure and the connection to a power system requires techno-economic analyses. For the wind farm and the collector network, the analyses provide an optimal topology, voltage level, number and dimension of the interconnection cables and a number and dimension of offshore collector and export substations. The same analyses provide also optimal technology (HVAC/HVDC), voltage level, topology, and the number of export cables from the offshore substation(s) to the power system. In the Åland case environment, the distances and powers are technically and economically suitable for both HVAC and HVDC technologies. However, with the cost analyses, the optimal technologies can be selected for each wind farm separately. In Figure 4.5, the principle of cost curves of AC and DC technologies is presented.

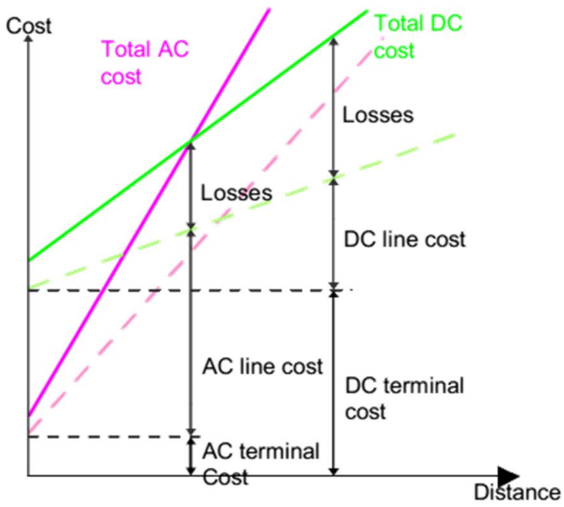



Figure 4.5. Cost curves of DC and AC technologies.

In the analyses, a large amount of background data and parameters is included. The most relevant data are technical and geographical constrains and installation depths of turbines and wind farms, unit costs of electricity network components and installations (€/pcs., €/km, €/MW) and peak operation time of losses (h/a) and price of losses (€/MWh). In Figure 4.6, investment cost of an HVDC cable is presented as the function of share of subsea installation.

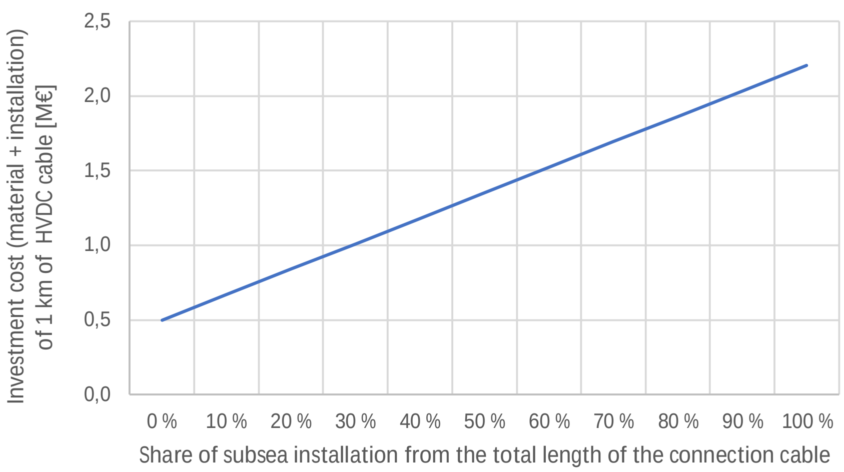



Figure 4.6. Example of network unit cost: Investment cost of HVDC cable as a function of share of subsea installation.

In Figure 4.7, reference originated investment costs are presented for offshore substation as the function of nominal power of the substation.

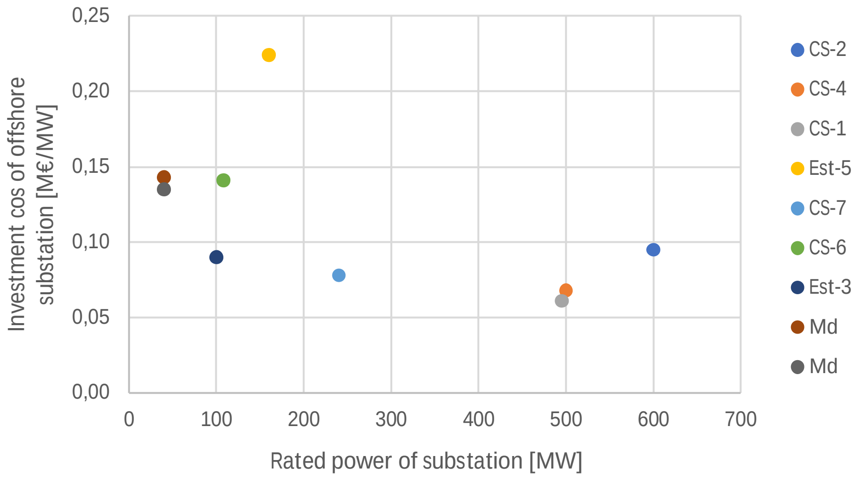



Figure 4.7. Offshore substation prices (M€/MW) as a function of rated power [MW].

In addition to the HVDC cabling costs and offshore substation costs, the unit costs for other network components (platforms, transformers, converters, etc.) are defined in the study. In theory, there are numerous alternatives for interconnection (routes) of different wind farms to the power system. In addition to this, different technologies as well as different voltage levels can be utilized into interconnection solution. In this study, we limit possible solutions to the most interesting and economic alternatives.

### *4.1.2 Interconnection alternatives*

Figure 4.8 presents all the connection route alternatives of the wind farms analyzed in the study. Red color indicates that the connection is more feasible to build with the HVAC technology, blue line color indicates that the HVDC technology is more feasible. Depending on parameters, the HVDC technology is economical in this power scale when the transmission distances are longer than 80–120 km. The technology choice can be made not only based on the lifetime costs of a connection, but the operational function of the connection (connection from a wind farm to a power system or a link between two power systems). It must be remembered, that although an interconnection is illustrated with a single line and to a single node in the power system, connections are formed by several parallel cables, depending on the transmitted power. In the power system the number of connection nodes and their locations is actually higher than indicated in Figure 4.8. The costs of parallel cables are taken into account to meet the required case-specific transmission capacity.

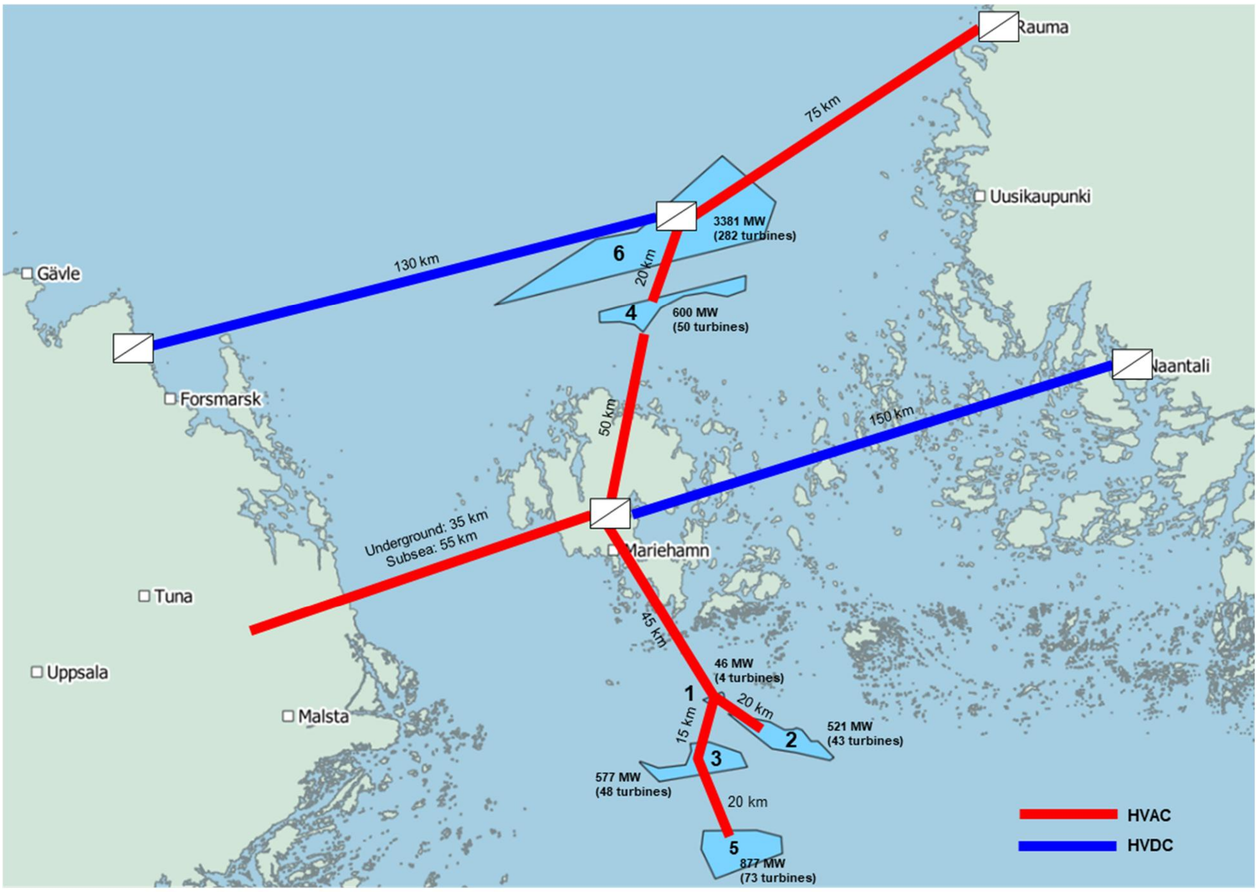



Figure 4.8. Network connection alternatives, their technologies (HVAC or HVDC) and distances from wind farms to continent analyzed in the study.

In the study, in total ten connection alternatives are analyzed. The first six ones are:

- **A1:** Wind farms F4 and F6, total 4 GW and 20 TWh connected to Finland (Rauma area) and wind farms F1, F2, F3 and F5 are connected to Finland (Naantali area) through Åland
- **A2:** Wind farms F4 and F6, total 4 GW and 20 TWh connected to Finland (Rauma area) and wind farms F1, F2, F3 and F5 are connected to Sweden (Tuna area) through Åland
- **A3:** Wind farms F1–F6, total 6 GW and 30 TWh connected to Finland (Naantali area)
- **A4:** Wind farms F4 and F6, total 4 GW and 20 TWh connected to Finland (Rauma area)
- **A4b:** Wind farm F6, total 3.4 GW and 17 TWh connected to Finland (Rauma area)
- **A5:** Wind farms F1, F2, F3 and F5 are connected to Sweden (Tuna area) through Åland

In Figure 4.9, connection alternatives A1 to A5 are presented.

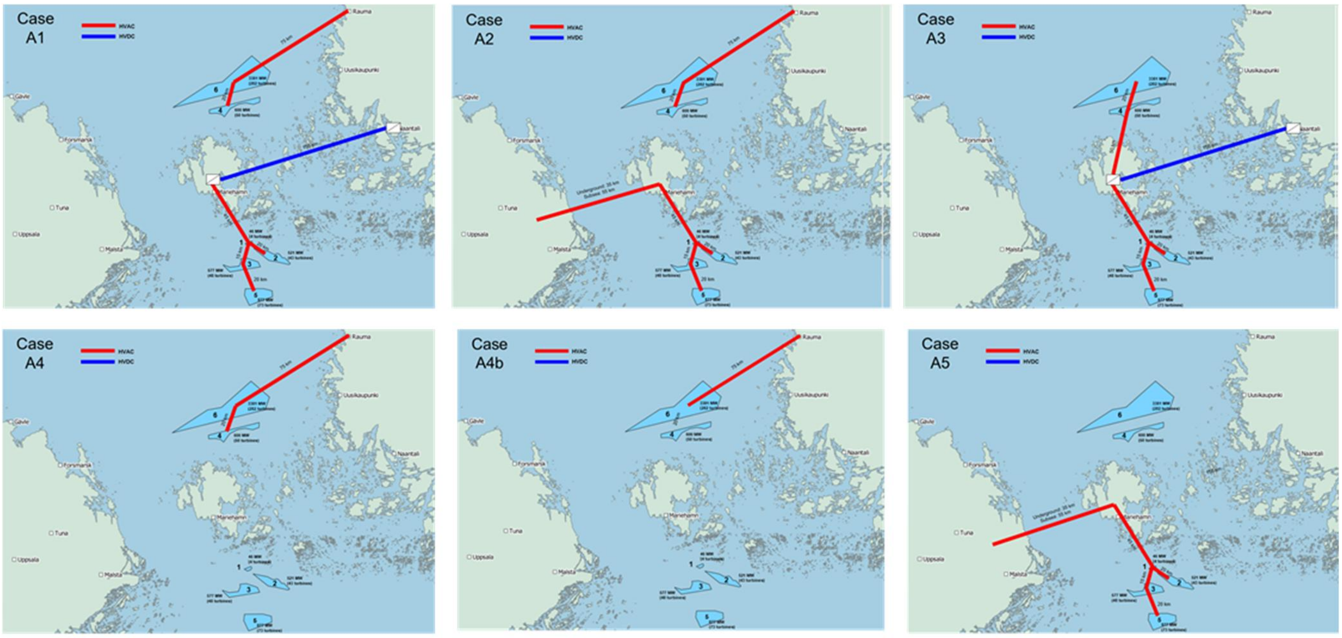



Figure 4.9. Network connection alternatives, A1–A5 (HVAC=red, HVDC=blue)

In each alternative, the lifetime costs consist of investment costs (material and installation) and operational costs (loss costs, maintenance). The costs are defined for each network level (wind farm collector network, offshore collector substations, export cables and export substations and substation in the power system end). The capacity of cables, transformers, and converters (if needed) are dimensioned and based on the peak power of the case area. In the end, the total costs are set in proportion to the delivered energy taking into account the losses in the whole transmission chain. The lifetimes of the components vary from 20 to 40 years.

In Table 4.2, the case-specific costs (€/MWh) of interconnection are presented. The results indicate that in the scale of Åland wind power vision, the cost of transmission of energy from the wind farms to the power system vary from 15 to 34 €/MWh. The costs are lower in the northern part alternatives due to a shorter distance to the power system and relatively high generation capacity of the wind farms. These costs do not include generation costs, which are assumed to be equal (€/MWp) for all areas.

Table 4.2. Costs of interconnection in alternatives A1–A5. Costs of generation are excluded.

| Case | CAPEX [Mrd.€] | CAPEX [M€/MW] | CAPEX [M€/a] | OPEX [M€/a] | **Cost of interconnection [€/MWh]** | Compared to cheapest (A4b) [%] |
|---|---|---|---|---|---|---|
| A1 (6 GW, 30 TWh) | 8.3 | 1.38 | 544 | 136 | **23.3** | 148 |
| A2 (6 GW, 30 TWh) | 7.8 | 1.30 | 508 | 98 | **20.9** | 133 |
| A3 (6 GW, 30 TWh) | 11.1 | 1.84 | 740 | 232 | **33.6** | 214 |
| A4 (4 GW, 20 TWh) | 4.2 | 1.06 | 273 | 52 | **16.8** | 106 |
| A4b (3.4 GW, 17 TWh) | 3.4 | 1.01 | 219 | 41 | **15.7** | 100 |
| A5 (2 GW, 10 TWh) | 3.6 | 1.77 | 235 | 46 | **29.2** | 186 |

In Figure 4.10, a share of CAPEX for different network levels is presented for the alternative A4 (Wind farms F4 and F6, totally 4 GW and 20 TWh connected to Finland). In Figure 4.10, the collector network costs include farm inter-array cables, the export cable costs include HVAC export cables, the platform cost includes offshore platforms at F4 and F6. The substation cost includes offshore substations and onshore substations at continent.

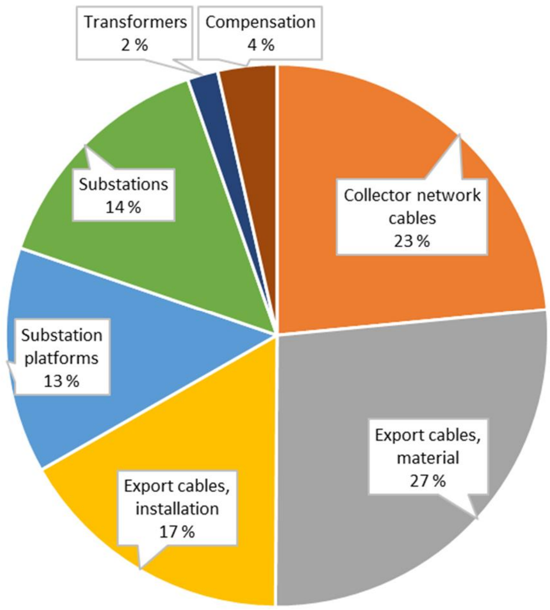



Figure 4.10. Case A4 CAPEX cost structure.

### 4.1.3 *Wind farms and interconnector*

The study focuses on defining the connection costs of wind farms in the Åland environment. In some cases, wind farm(s) may be located in an area, where the farm connection can provide the possible base for the interconnection of two power systems (Nieradzinska, K. et al. 2016). This is also the case in Åland. In the northern areas, north of wind farm F6, there are two HVDC subsea connections between Finland and Sweden, operated by the Finnish and Swedish transmission system operators Fingrid and Svenska Kraftnät. The Fenno–Skan 1 (commissioned in 1989) is a monopolar system with a maximum transmission rate of 550 MW. Fenno–Skan 2 (commissioned in 2011) has transmission rate 800 MW (Fingrid). The limited capacities and operational requirements in the power system do not enable them to be used for the interconnection role of the studied wind farms. However, the future growth in the use of electricity and growing share of renewables (wind power) increases the need for power balancing capacities in the power system. This raises an interest to study the alternatives, where the case area wind farms would be part of new HVDC interconnector between Finland and Sweden.

In Figure 4.11, more connection alternatives are presented. In all these alternatives (A6 to A9), the HVDC technology is used. Cases A8 and A9 represent interconnector solutions, where the same connection could be used to both directions, from wind farm(s) to Finland and Sweden.

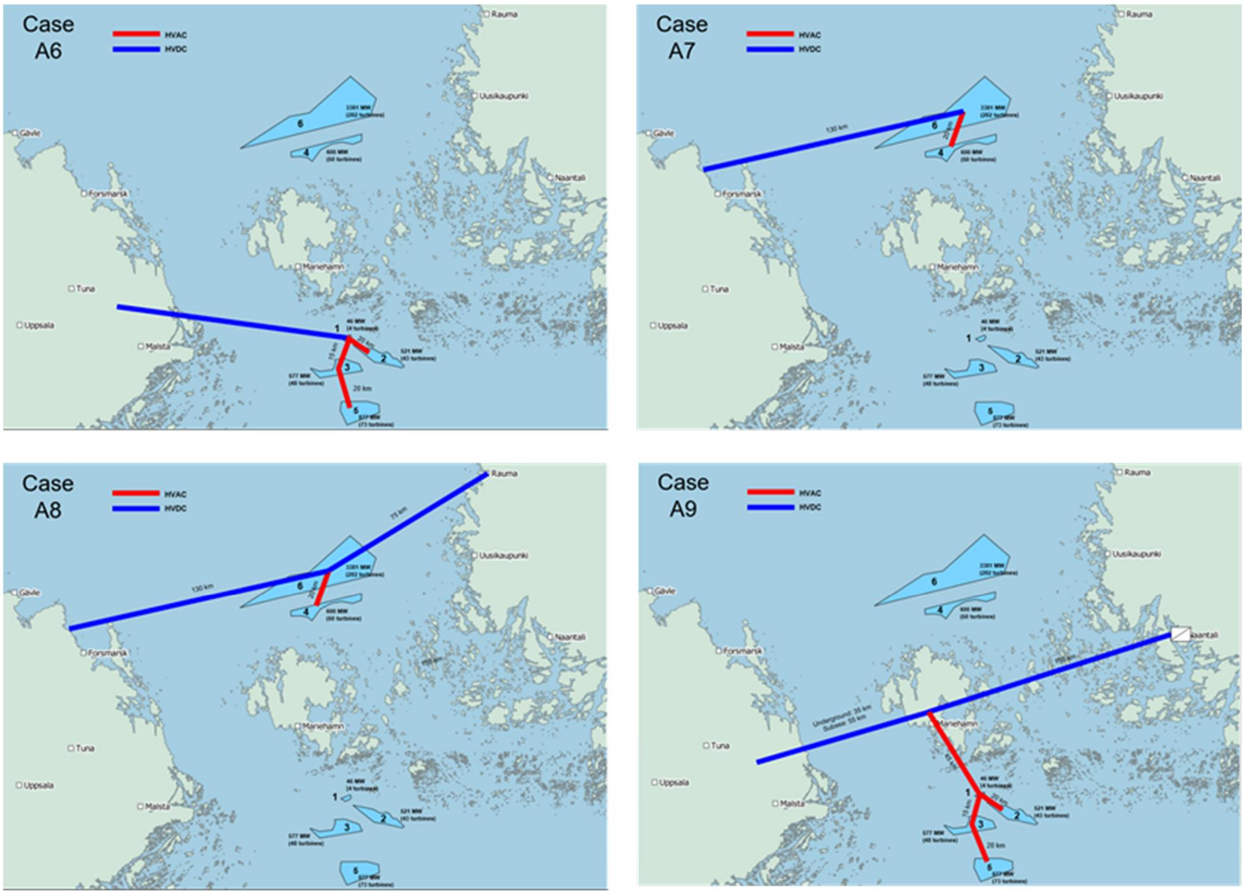



Figure 4.11. Network connection alternatives, A6–A9 (HVAC=red, HVDC=blue)

In Table 4.3, case-specific costs (€/MWh) of interconnection alternatives (A6-A9) are presented.

Table 4.3. Costs of interconnection (cases A6-A9).

| Case | CAPEX [Mrd.€] | CAPEX [M€/MW] | CAPEX [M€/a] | OPEX [M€/a] | **Cost of interconnection [€/MWh]** | Compared to cheapest (A4b) [%] |
|---|---|---|---|---|---|---|
| A6 (2 GW, 10 TWh) | 2.5 | 1.25 | 173 | 55 | **23.0** | 146 |
| A7 (4 GW, 20 TWh) | 5.3 | 1.31 | 359 | 97 | **23.2** | 148 |
| A8 (4 GW, 20 TWh) | 4.9 | 1.24 | 342 | 90 | **22.0** | 140 |
| A9 (2 GW, 10 TWh) | 3.8 | 1.88 | 257 | 78 | **34.3** | 218 |

The results indicate that the connection cost allowing energy transmission from the wind farm to both Finland and Sweden vary from 22 to 34 €/MWh. When comparing the case A8 with the case A4 presented earlier, the additional cost from this bi-directional interconnector is approximately 5 €/MWh.

There are technological uncertainties regarding HVDC multipoint interconnectors, especially operating offshore. However, at the EU level, the interest is high to ease the connection of renewables into a power system and enforce market integration and co-operation of TSOs, creating a promising basis for Åland offshore wind.

# 5 Hydrogen Production

Electrolysis process uses electricity to split purified water into hydrogen and oxygen. Alkaline-type electrolyzers employ an aqueous solution of potassium hydroxide (KOH) in the hydrogen generation unit to increase its conductivity. The produced hydrogen is separated from the water solution, after which the oxygen impurities are removed, and the purified hydrogen is dried. Nearly pure hydrogen is then compressed in preparation for its transport or intermediate storage. (Ivy, 2004).

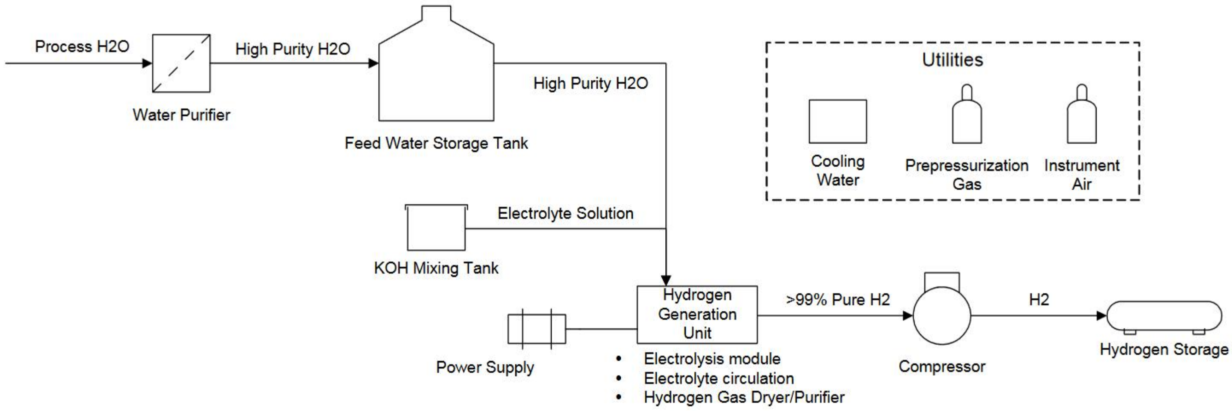



Figure 5.1. Flow diagram of hydrogen production process (Ivy, 2004).

## 5.1 Electrolyzer technology alternatives

Today, most commercial electrolyzers are based either on alkaline electrolysis (AEL) or proton-exchange membrane (PEM). Both have their own benefits and drawbacks. Other electrolyzer technologies also exist, for instance, solid oxide electrolyzers (SOEC), but the technological maturity is significantly lower.

Alkaline electrolyzers use a liquid electrolyte solution, which could potentially leak to the environment. The solution additive, KOH, is a strong base and thus highly corrosive. The electrolyte solution also needs to be replaced a few times during the electrolyzer lifetime, which can represent a small increase in operational expenses. Proton Exchange Membrane (PEM) electrolyzers employ a solid polymer electrolyte instead, so it avoids the aforementioned problems. PEM electrolyzers can also be operated in higher pressures than alkaline electrolyzers, and they can be operated more rapidly (e.g. fluctuating electricity input). The disadvantage of PEM electrolyzers is that manufacturing requires precious materials (especially platinum) and are thus often more expensive. PEM electrolyzers are also slightly lighter, more compact, and could have a higher efficiency. However, PEM electrolyzers have a shorter application history and less industrial experience. (IRENA 2020, Ivy 2004, ERM 2019)

Some practical decisions related to hydrogen production are:

- placement of electrolyzers: onshore or offshore
- selection of electrolyzer technology (AEL or PEM) and their supplier. Key parameters that influence the decision are
    - procurement cost of the electrolyzer units
    - dynamic capabilities of the electrolyzers (load following if directly coupled with wind turbines)
    - maintenance, utility, and operation requirements
    - operation pressure of the electrolyzers
    - special considerations that arise in marine applications (shipping and logistics, supervision, maintenance, design safety factors & regulations, utilities, as well as weight, size, and orientation restrictions
- procured capacity of the electrolyzer units. For instance, are the units scaled according to the wind peak power, or below the peak to maximize full load hours
- safety and regulation aspects, leakages and disasters
- environmental footprint of the produced hydrogen, which includes also the impact of water treatment

## 5.2 Efficiency and by-products

Overall conversion efficiency of electricity to hydrogen typically ranges from 43% to 67%[1]. The electrolyzer stack itself is responsible for most of the losses in the process (about 70%), while the remaining share is caused by power electronics losses and other auxiliary components (Koponen, 2020). Electrolyzers require DC power, and typically have their own transformer included, with typical input voltage from 6.6 kV to 35 kV AC (Nel, 2020).

Residual heat from the electrolysis process is available at a temperature of about 70 °C. Some of the excess heat could potentially be utilized in water purification, as discussed in Subsection 5.3. Other potential uses for the heat are ice prevention and space heating. Oxygen is also formed in electrolysis. Pumping of oxygen to the ocean floor has been previously piloted in a 4-year pilot in Byfjorden, Sweden in Baltic Deepwater Oxygenation project (Marsys, 2013). The concept is to reduce the negative effects of anthropogenic nutrient inputs to the Baltic Sea, but it should be studied further whether electrolyzers could be utilized in a similar manner.

[1] system efficiency, including auxiliary electricity consumption of pumps, blowers, fans etc. Defined from electricity to lower heating value of hydrogen in this study

### 5.3 Water purification

Water purification is required for electrolysis, although the specific requirements can vary depending on electrolyzer type and manufacturer. In a marine environment, desalination would first be required, before the de-ionization treatment. Typically, the freshwater pretreatment is included in electrolyzer configuration, and its contribution is not very significant in final hydrogen price (by a rough estimate about 1-2%).

Dominant desalination technologies are distillation and reverse osmosis. Multiple-effect distillation can utilize heat at temperatures of 70-75 °C (Panagopoulos et al., 2019), which also coincides with the temperature levels typically obtained from cooling of the electrolyzer stack. The desalination heat demand for multiple-effect distillation (7.7 – 21 kWh/$m^3$) could easily be covered by the excess heat from electrolysis (<2% of available heat would be required). The cost of desalination with multiple-effect distillation is around 0.8 €/$m^3$ (Panagopoulos et al., 2019), which is comparable to the cost of traditional water pretreatment discussed earlier.

Brine is a by-product formed during a desalination process, which could potentially have an impact on the local marine ecosystem due to its high salinity and residual from pretreatment chemicals. Thermal desalination (i.e. distillation) processes are estimated to have a bigger environmental impact compared to reverse osmosis systems. (Panagopoulos et al., 2019).

In later stages of the project, different water desalination and purification technologies should be compared in terms of costs, environmental effects, and energy consumption. However, the challenges and costs associated with water purification are likely relatively minor in terms of the overall process.

### 5.4 Compression

The compression of the hydrogen consumes a notable portion of the electricity. Common technical alternatives include positive displacement compressors (e.g. reciprocating piston compressor) and flow compressor (e.g. centrifugal compressor). Selection of compressor is primarily dictated by the throughput and desired compression ratio. Displacement compressors are favorable for larger compression ratios and lower throughputs, but centrifugal compressors are viable for pipeline applications (EERE, 2021). About 1.5 - 2.4 $MWh_{el}/ton_{H2}$ is typical for final pressures of 50-100 bars from ambient conditions when performed in conventional compression. Thus, compression electricity demand could represent about 3-4% of the total produced electricity produced in the wind farm. However, the electrolyzer itself can operate in higher pressures, which means that the product $H_2$ could readily be obtained at 30 bar, for instance. An additional compressor would most likely be required regardless[2], as the pressure should be increased to 50-100 bars required for pipeline

[2] Polymer electrolyte membrane (PEM) electrolyzers could potentially achieve sufficient pressures, but their commercial availability and price should be compared to conventional alkaline systems

transmission. This initial electrolytic compression reduces the mechanical compression demand, but simultaneously results in decreased Faraday efficiency of the electrolyzer. An in-depth study would be required to determine whether the electrolytic compression of $H_2$ would be favorable, as it is dependent on multiple factors (e.g. pressure level, capacity, lifetime and maintenance costs, manufacturing costs, compression technology). (IRENA, 2020)

Hydrogen purification is required prior to compression, but these components are typically provided for by the electrolyzer manufacturer. Mass-wise, the largest impurity is water vapor, which is removed to prevent condensation in later stages. Trace amounts of electrolyte solution (e.g. KOH) can also be present. Other typical contaminants are atmospheric constituents, such as oxygen, nitrogen, and argon.

### 5.5 Offshore hydrogen production

Conventional electrolyzer systems are rather large, which should be acknowledged in offshore applications. For instance, a 30 MW electrolyzer system has a footprint of roughly 35 x 35 m and weight of over 140 tons. However, many companies have recently introduced concepts for enabling production of hydrogen directly at sea.

Tractebel has developed a platform concept for offshore hydrogen production, which includes seawater desalination, electrolysis, and compression (Tractebel, 2019). A similar solution has been devised by ERM, which uses a floating dock which is anchored to the seabed approximately 60 meters below the surface. After a thorough comparison, ERM concluded that the floating dock solution integrated with each wind turbine and submarine hydrogen pipeline was the most cost-efficient solution, beating the other two candidates that were considered (i.e. HVDC transmission coupled with onshore electrolysis, and a single centralized electrolyzer offshore station with submarine pipeline). Projected hydrogen production costs using the ERM's solution are estimated to be 2.1 - 2.6 €/$kg_{H2}$. ERM's Dolphyn project continues with a 2 MW pilot phase that is scheduled to be online by 2023, with a follow-up pre-commercial 10 MW unit by 2026. (ERM, 2019)


a b

Figure 5.2. Offshore hydrogen platform concepts of Tractebel (a) and floating integrated structure by ERM (b). (Tractebel, 2019, ERM, 2019)

In Denmark the Danish Energy Agency shows solutions for large scale floating factories as part of the planned “energy-islands” that have been indicated in the Danish maritime spatial plan as possible future steps in developing the energy production at sea (Danish energy agency, 2021).

Figure 5.3. Energy island concept developed by COWI on behalf of the Danish Energy Agency (2021).

There are also other projects related to offshore hydrogen production.

- Siemens-Gamesa and Siemens Energy are jointly developing over the next five years an offshore wind turbine which would have a fully integrated electrolyzer unit at its base (Siemens Gamesa, 2021).
- PosHYdon, which aims to produce hydrogen at an existing oil platform, (Neptune Energy, 2019)
- Oyster, a shoreside pilot for a compact and rugged electrolyzer directly integrated with a wind turbine. (BBC,2020)
- AquaVentus, where hydrogen is produced offshore and transported to the island of Helgoland off the coast of Germany, before delivering the hydrogen to mainland via a pipeline. (RWE, 2020)

Oil offshore platforms are remarkably similar in construction to the previously mentioned offshore centralized hydrogen platforms, so the structure itself should not be a monumental challenge. More problems could be expected with hydrogen-related infrastructure that is introduced into marine environments. Traditional oil rigs apparently have procurement costs of 175 – 225 million USD for a jackup[3] structure, and 500 – 700 million USD for floating structures (Offshore magazine, 2012). Given the recent increase in steel price, the higher end of the spectrum is likely to be more realistic.

To apply these technologies in practice, discussions should be initiated with the various companies to get more technical and cost-related details, as well as discussing potential development timelines. Given that many of these endeavors are currently in pilot or pre-commercial stage, implementation in scale cannot be realistically expected in the immediate future. The platforms would form a considerable part of the overall costs, and the reliability of the estimated platform costs are rather high. If islets (small rocky islands) could be used for hosting a hydrogen conversion platform, the costs could be decreased significantly compared to floating or seabed foundations.

## 5.6 Cost of hydrogen

Currently, the levelized cost of green hydrogen, i.e. hydrogen produced using electrolysis technology and renewable electricity, is between 2.5 – 5.5 €/kg$_{H2}$. Grey hydrogen, i.e. fossil-based hydrogen with carbon capture and storage, is expected to have price of around 2 €/kg (European Commission, 2020). Green hydrogen could potentially reach as low as 0.85 €/kg$_{H2}$ (1 USD/kg) as illustrated in Figure 5.4. The lowest hydrogen production prices are likely reached in locations where renewable energy sources are abundant, and thus electricity prices low. Low electricity price is one of the most important factors for determining hydrogen price with electrolyzer technology. Manufacturing costs

[3] A platform which is built onshore and towed to the construction site, where the premanufactured legs are lowered into the seabed and the platform is 'jacked' above sea level

of electrolyzers are likely to decrease significantly due to economy of scale, resembling a similar development that has been observed with solar photovoltaics technology. (IRENA, 2020).

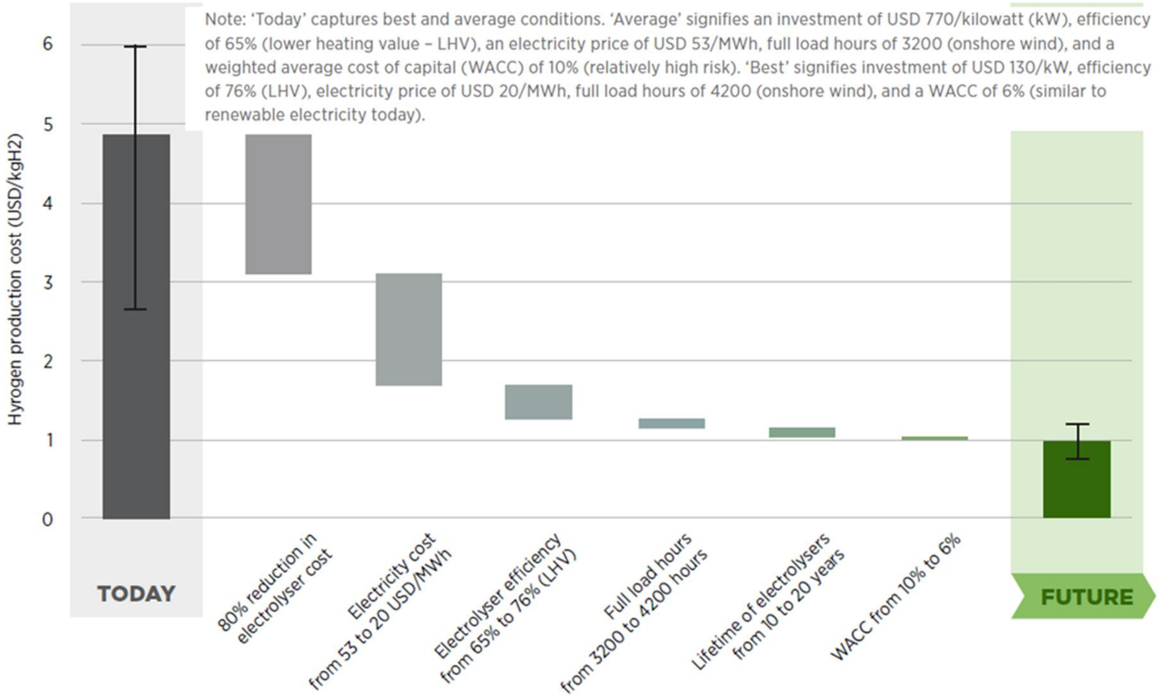



Figure 5.4. Relative impact of different factors in levelized cost of hydrogen (modified from IRENA, 2020)

## 5.7 Hydrogen pipeline transmission

Pipeline transmission of $H_2$ is cost-effective in large scale according to previous studies. Stiller et al. (2008) studied various alternatives for delivering hydrogen power (1-4 GW) from Norway to Germany, where hydrogen pipeline was one candidate. Studied renewable[4] alternatives included the following:

- onshore electrolysis in southern Norway and transmission via a submarine hydrogen pipeline to Germany
- onshore electrolysis in northern part of Norway and ship transportation to Germany
- transmission of electricity in HVDC line to Germany, followed by onshore electrolysis

From these alternatives, HVDC was found to be more expensive for the northern part (where hydrogen shipping was preferable) as well as the southern part (where hydrogen pipeline was superior).

[4] Hydrogen production with steam methane reforming was also studied, as well as conventional natural gas transmission followed by steam methane reforming in Germany.

Similarly, the study by ERM (2019) also concluded that hydrogen pipeline is preferable to HVDC transmission. According to the study, direct production of hydrogen at each wind turbine was the least cost solution as opposed to having a local HVAC internal grid coupled with centralized hydrogen production. The analyzed scale was about 4 GW, and transport distance below 250 km.

Based on these studies, the transmission of hydrogen in pipelines can be cost-effective if hydrogen is the desired end product. On the other hand, electricity transmission is more flexible in terms of its final use, and it avoids the heavy efficiency loss of hydrogen conversion in an electrolyzer. Some additional benefits of hydrogen pipeline include

- Energy storage schemes are relatively easy to implement. To a limited extent, the pipeline itself can store energy, or external hydrogen storages can be utilized (see Subsection 5.8.2 for details).
- Economy of scale with larger flow quantities
- Modest energy losses during transportation. Compression of hydrogen is the primary concern.

## 5.8 Modelling and results

The modelling focused on obtaining costs of hydrogen production and transmission using pipelines. The costs of wind turbines are left outside the scope of the study. In addition to the cost analysis, some preliminary investigations were done for the feasibility of hydrogen storages. Assumptions and inputs of the simulation parameters are presented in Table 5.1.

Table 5.1. Modelling parameters

| Component | Category | Unit | Value | Comment |
|---|---|---|---|---|
| **Electrolyzer** | Investment cost | €/kW | 600 | Assumed value for 2030 |
| | Annual full load hours | h | 5000 | Matched with wind turbine generation |
| | Efficiency | % | 60 | • Typical range 52-69%.<br>• Defined from electricity to lower heating value of hydrogen<br>• Includes electrolytic compression to 30 bar and other balance-of-plant consumption (pumps, power electronics) |
| | Annual fixed maintenance | % | 1.5 | Fixed percentage of total electrolyzer investment |
| | Variable operation and maintenance | €/kgH2 | 0.07 | Water purification, desalination |
| | Electricity price | €/MWh | 0 | Not included in analysis |
| | Interest rate | % | 5 | |
| | Lifetime | years | 20 | |
| **Hydrogen pipeline** | Maximum flow velocity | m/s | 20 | Typical operation values from other references range from 10-20 m/s. Maximum flow velocity would only be reached in rare peak production occurrences. |
| | Operation and maintenance | % | 5 | Typical range 1-8%. Fixed percentage of total pipeline investment. |
| | Investment cost | | | Defined from a regression model initially obtained from realized natural gas pipelines. Correction factors are used to obtain results for hydrogen offshore pipelines. Cost function is dependent on diameter and pipe length, but not pressure. |
| | Annual full load hours | h | 5000 | Matched with wind turbine generation |
| | Interest rate | % | 5 | |
| | Lifetime | years | 40 | |

Table 5.1. Modelling parameters (continue)

| | | | | |
|---|---|---|---|---|
| **Hydrogen compressor** | Investment cost | M€/MW | 3.4 | |
| | Annual fixed O&M | % | 3 | |
| | Specific electricity consumption | | | Calculated from isothermal compression with 60% efficiency. Ideal gas behavior assumed. Values ranged from 0.16 to 0.22 MWh/ton$_{H2}$. |
| | Inlet pressure | bar | 30 | Electrolyzer pressure assumed to be at 30 bar. |
| | Outlet pressure | bar | 30 | Pressure losses estimated using Darcy-Weisbach equation, with friction factor correlation from Colebrook-White. |
| | Electricity price | €/MWh | 0 | |
| | Annual full load hours | h/a | 5000 | Matched with wind turbine generation |
| | Interest rate | % | 5 | |
| | Lifetime | years | 20 | |
| **Platform** | Specific investment | M€/MW | 0.29 | Defined based on input electrical energy |
| | O&M | % | 2 | |
| | Lifetime | years | 20 | |
| | Interest rate | % | 5 | |
| **Hydrogen storage** | Specific investment | €/MWh | 2300 | Defined for lower heating value of hydrogen |
| | Annual storage cycles | | | Variable |
| | O&M | | | Not included |
| | Lifetime | years | 40 | |
| | Interest rate | % | 5 | |

### 5.8.1 Scenarios

Three hydrogen gas scenarios were chosen for comparison with transmission of electricity scenarios A4, A4b and A5:

- **G4:** Wind farms F4 and F6 connected to Finland (Rauma area)
- **G4b:** Wind farm F6 connected to Finland (Rauma area)
- **G5:** Wind farms F1, F2, F3 and F5 connected to Sweden (Tuna area) through Åland

A summary of different studied scenarios is given in Table 5.22. Since the electricity-scenarios are not directly comparable with gas scenarios due to different end products, modified versions of A-scenarios have been generated. These include an electrolyzer at the final destination, so that both versions are capable having hydrogen as the final delivered product. The modified electricity scenarios have an additional suffix "+", so for instance A4+ and G4 scenarios are comparable in terms of final product, but with different transfer technology (A4+ transmission is done with HVAC/DC, whereas G4 utilizes hydrogen pipeline). Identical approach has been taken for the A5 scenario. The differences between the normal (A4), modified (A4+), and gas (G4) scenarios are described in Table 5.3.

Table 5.2 Summary of hydrogen gas scenarios

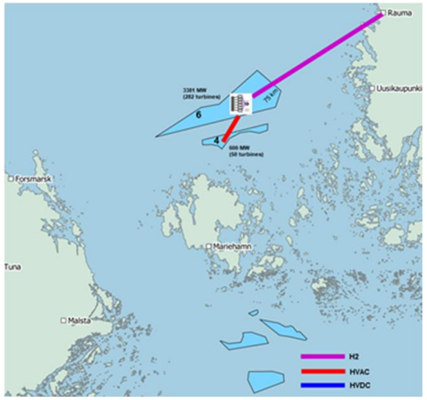
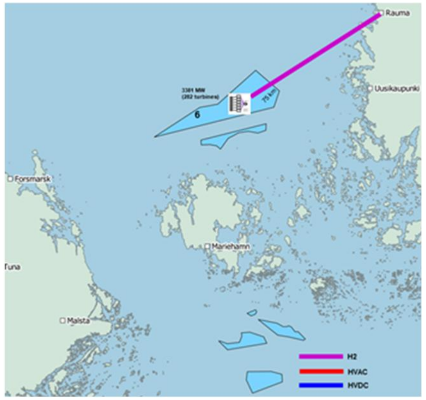
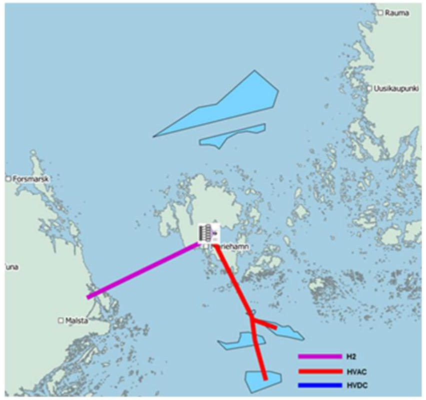
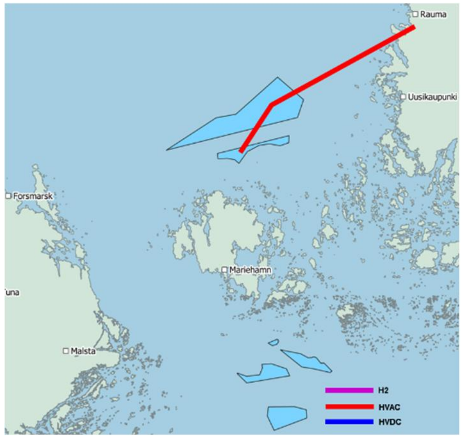
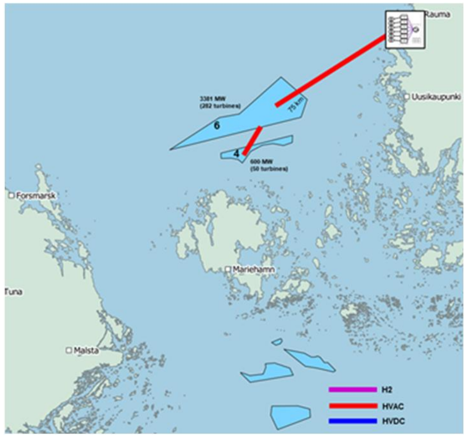
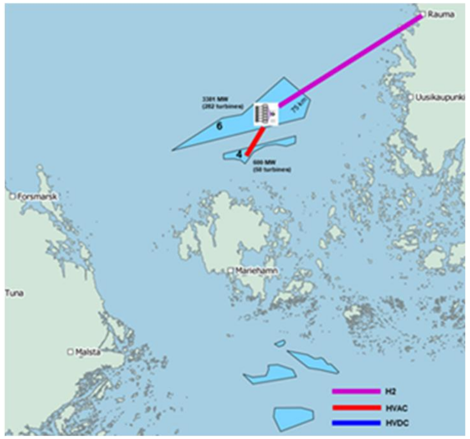
| Scenario | G4 | G4b | G5 |
|---|---|---|---|
| Base scenario | A4 | G4 | A5 |
| Modifications | • Offshore electrolysis on platform<br>• Pipeline instead of HVAC to Finland | • Farm 4 is not included | • Onshore electrolysis on Åland<br>• HVDC connection between Åland and Sweden converted to pipeline |
| |  |  |  |
| Annual electricity generation (TWh) | 20.3 | 17.2 | 10.3 |
| Electrolyzer electricity input (TWh) | 20.1 | 17.1 | 10.2 |
| Peak transmission capacity (GW) | 2.4 | 2 | 1.2 |

Table 5.3. Description of the main differences between a normal, modified and gas scenarios

| Scenario | A4 | A4+ | G4 |
|---|---|---|---|
| Product at destination | Electricity | Hydrogen | Hydrogen |
| Transfer method | HVAC | HVAC | Pipeline |
| |  |  |  |

### 5.8.2 Results

Pipeline scenarios (G4 and G5) achieved lower cost for transport compared with electricity transmission scenarios including electrolyzers (A4+ and A5+). If there is a demand for hydrogen in the destination, pipeline transmission should be considered as a viable alternative, because it had both lower investment (e.g. 5.1 B€ in G4 vs 6.6 in A4+) and slightly lower energy losses (e.g. 0.3 TWh/a between G4 and A4+). Pure electricity scenarios (A4 and A5) and gas scenarios (G4 and G5) are not directly comparable because the end products are not the same. Hydrogen conversion results in a significant reduction in net transferred energy, as well as increased investment due to inclusion of an electrolyzer. The cost of transmission presented in Table 5.44 is highly dependent on the assumed electrolyzer price. Electrolyzer price is assumed to be the same for both offshore and onshore solutions.

Table 5.4. Comparison of costs and performance of scenarios. Wind generation cost not included in any scenarios

| **Case ID** | | **A4** | **A4+** | **G4** | **A5** | **A5+** | **G5** |
|---|---|---|---|---|---|---|---|
| Method of transmission | | Electricity | Electricity | Hydrogen | Electricity | Electricity | Hydrogen |
| Final product | | Electricity | Hydrogen | Hydrogen | Electricity | Hydrogen | Hydrogen |
| Generation capacity | GW | 4.0 | 4.0 | 4.0 | 2.0 | 2.0 | 2.0 |
| Annual generation | TWh/a | 20.3 | 20.3 | 20.3 | 10.3 | 10.3 | 10.3 |
| Investment | B€ | 4.2 | 6.6 | 5.1 | 3.6 | 4.8 | 3.9 |
| Operation and maintenance | M€/a | 52 | 88 | 79 | 46 | 64 | 61 |
| Total annual cost | M€/a | 325 | 552 | 458 | 281 | 396 | 336 |
| Net energy transfer | TWh/a | 19.4 | 11.6* | 11.9* | 9.6 | 5.8* | 6.1* |
| Cost of transmission | €/MWh | 16.8 | 47.5* | 38.5* | 29.2 | 68.8* | 54.8* |
| * Calculated for energy unit of hydrogen (lower heating value). Includes electrolyzer costs but not costs associated with wind turbines or electricity | | | | | | | |

According to the analysis and assumptions used in this study, the largest cost items are electrolyzers, potential platform structures, and the internal collector network for the wind turbines, see Figure 5.5 – 5.7. Cost distribution for scenarios A5, A5+ and G5 are in the Appendix II.

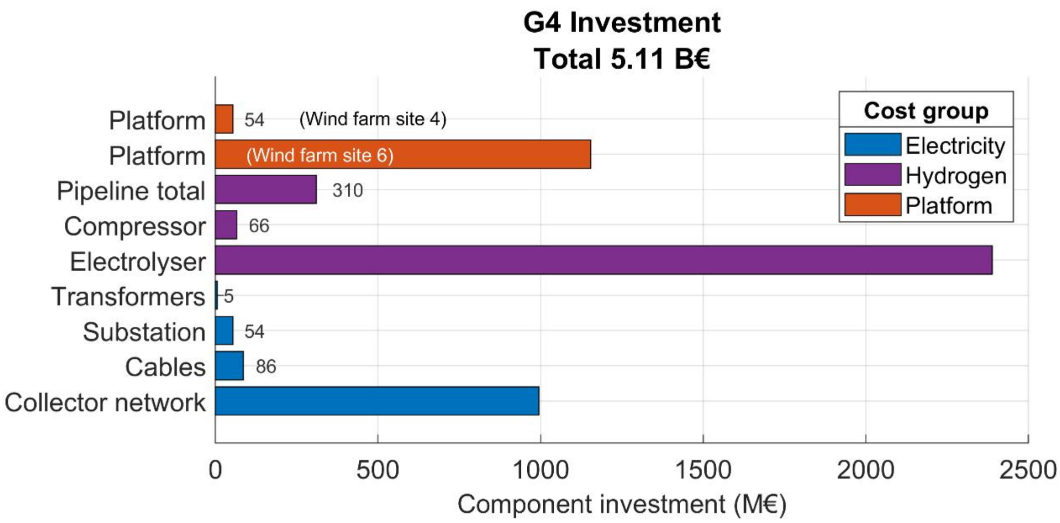



Figure 5.5. Investment cost distribution for G5 case.

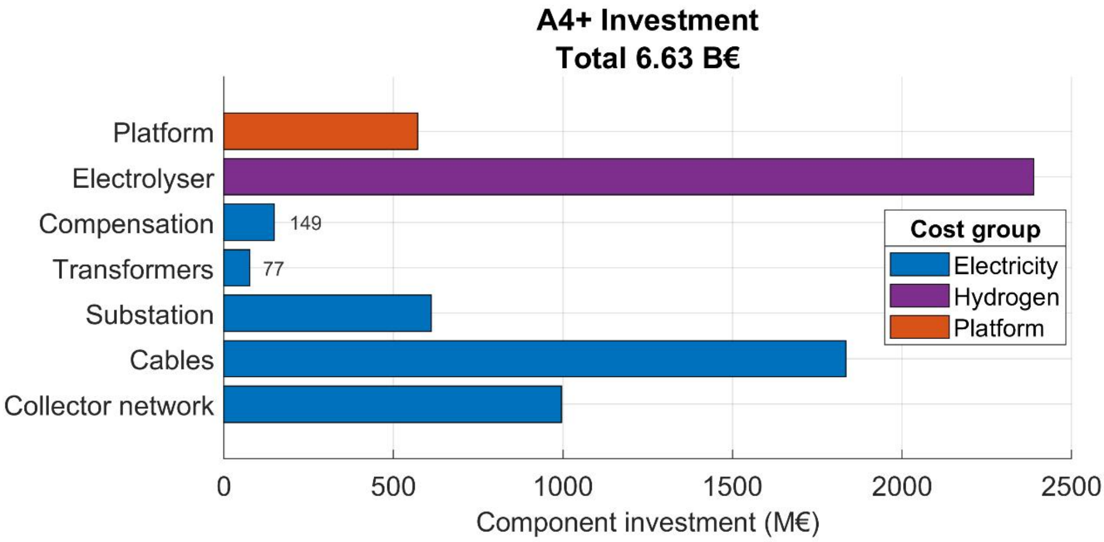



Figure 5.6. Investment cost distribution for A4+ case.

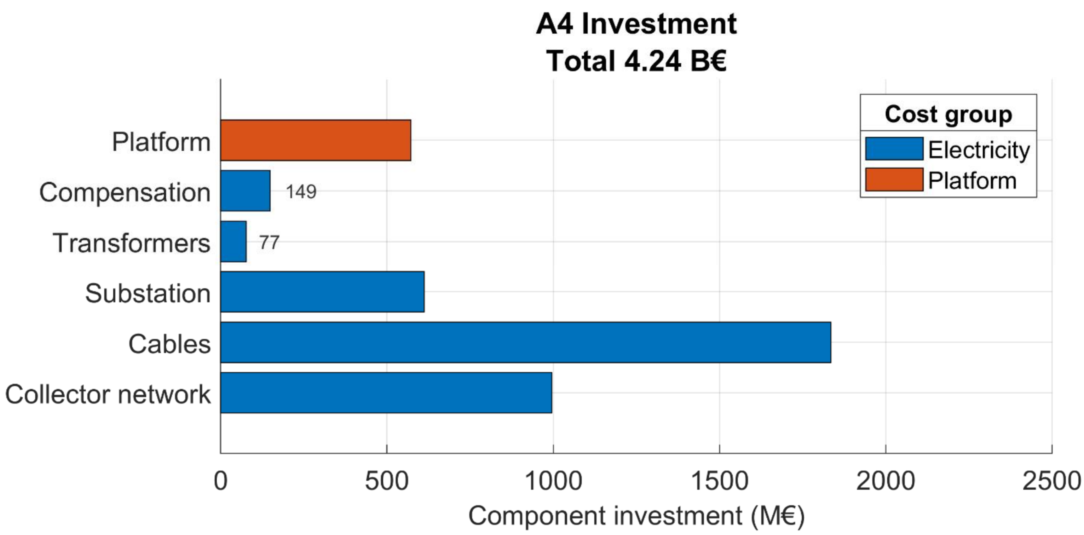



Figure 5.7. Investment cost distribution for A4 case.

Cost uncertainty can be expected to be quite high for different subsystems. Especially cost estimations for the platform structures varied between different references. Furthermore, there is still little practical experience in the industry for offshore hydrogen pipelines, and literature estimates can be somewhat optimistic compared with reality. Natural gas pipelines have been shown to have drastic cost escalations in some projects, which is a risk also for hydrogen applications, see Figure 5.8. On the other hand, the relative impact of pipeline is rather modest when compared with other cost items (Figure 5.5).

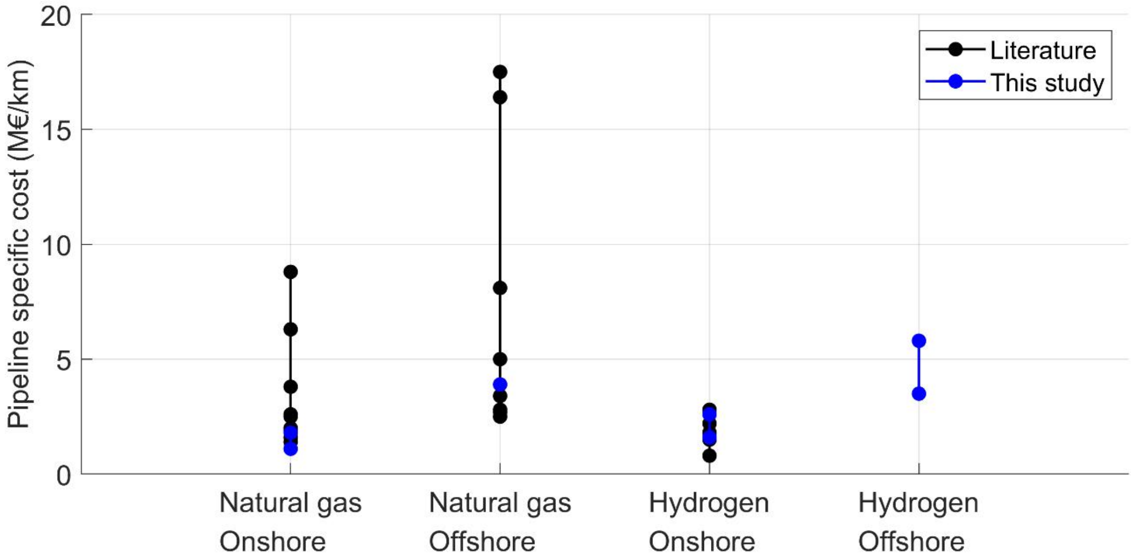



Figure 5.8. Investment cost for one kilometer of pipeline for different gases and onshore and offshore environments.

Hydrogen pipelines can store a moderate amount of hydrogen inherently. Storage capability of a hydrogen pipeline is dependent on the maximum pressure, diameter and pipeline length as illustrated in Figure 5.9. In essence, the operating pressure of the pipeline is increased as the amount of hydrogen in the pipeline increases. During normal operation, the pressure can be lowered in order to save in operating expenses. Depending on the hydrogen demand in the pipe outlet, the hydrogen pipeline could store anywhere from a few hours to few months' worth of hydrogen.

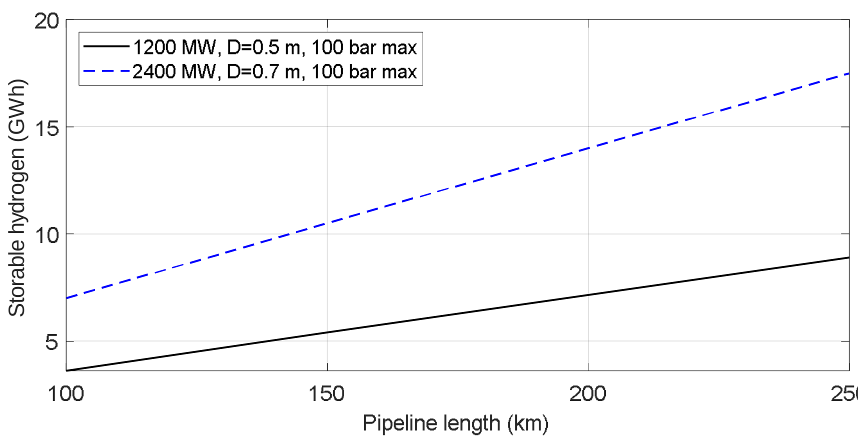



Figure 5.9. Energy storage capability as a function of distance for two differently sized hydrogen pipelines with equal maximum pressure.

Lined rock caverns can also be implemented for large-scale storages purposes. These lined rock caverns can be implemented in locations where naturally occurring salt caverns or other natural formations are not available. The key features of such caverns include (Cordis, 2002):

- a steel liner which provides a gas-tight inner shell for the stored material,
- a concrete layer, which acts as a cushion between the steel liner and rock, transferring pressure forces and smoothing the surface for the lining,
- the surrounding rock that withstands the forces arising from the internal pressure of the tank,
- a drainage system that prevents groundwater accumulation.

A 40 000 $m^3$ commercial pilot storage for natural gas has been in operation in Sweden since 2002. The storages could be deployed in depths of 100 – 150 meters below surface, with maximum storage pressures of 150 – 300 bar. (Johansson, 2014). As part of the HYBRIT steel decarbonization scheme by SSAB, LKAB and Vattenfall, the companies have investigated the research needs for implementing lined rock caverns specifically for hydrogen (Johansson, 2018). Hydrogen embrittlement is the primary concern raised by the study, which affects the steel grade selection of the inner liner. Other critical engineering concerns were not presented, but the development of numerical methods and risk-based design methods were mentioned. These could be beneficial in optimization of material thicknesses and adjusting for fluctuations in rock mass properties.

A significant factor for the levelized cost is how often the storage goes through a full cycle (i.e. what is the turnover, or the amount of material passing the storage relative to the maximum capacity) (Table 5.5). The pilot commercial project in Sweden was designed for 10 annual turnovers, although in early years of operation only 1 – 2 were achieved (Johansson, 2014).

Table 5.5. Levelized capital expense of excavated cavern storages for hydrogen. Operation expenses are not included (Ahluwalia et al., 2019)

| | | | | | |
|---|---|---|---|---|---|
| Annual storage cycles | - | 1 | 2 | 10 | 50 |
| Levelized cost of storage | €/$MWh_{H2}$ | 134 | 67 | 13 | 3 |

# 6 Risks and Opportunities

Offshore wind development includes several uncertainties. They may lead to losses, harm or even damage, and such uncertainties are called risks. However, uncertainties may also bring additional benefits, in which case they are opportunities.

In Åland offshore wind development, the uncertainties are related to, for example, technology used, packed ice, electricity and hydrogen markets, alternative electricity production methods, political and regulatory decisions, partners, and timing. The main uncertainties are reviewed in this chapter.

## 6.1 Technology

Offshore wind power and especially hydrogen technologies are under fast development. Though offshore wind farms have been developed and built for some time, new technologies for foundations, floating turbines, hydrogen productions at sea, etc. are in strong development (Kovalchuk, 2021). This leads to lowering production costs for both electricity and hydrogen.

## 6.2 Packed Ice

As an uncertainty and risk, especially from an investor's point of view, there is possibility of packed ice knocking down the whole or part of the wind farm and hydrogen production. This is an investor risk which requires many levels of reduction: in the beginning external estimate from Finnish Meteorological Institute or Sveriges meteorologiska och hydrologiska institute (SMHI). Further down the development chain, clearing the issue might require a test foundation and deeper studies to convince the investors. This risk is one of the first ones to study and tackle.

## 6.3 Marine Construction

The costs of marine construction are very much dependent on the construction methods. The final set up is depending on available ground (e.g. islets Rannörarna). The engineering work should be carried out by a marine construction specialist with long track record.

The costs presented in this study are on strategic level and should be treated as such.

## 6.4 Hydrogen market

Hydrogen market and hydrogen customers do not really exist in large scale. A lot of hype is created around the subject. Hydrogen ($H_2$) is an energy carrier and important ingredient for reduction of steel production, and in different molecule forms (e.g. methanol[5], ammonia[6]) important fuel as well as raw material for chemical industries. Hydrogen market does not exist in the extent as electricity market.

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[5] $CH_3OH$
[6] $NH_3$

Most probably the hydrogen customer and production would be one-to-one PPA's reducing long term risks for both parties. At Åland the electricity will be green. Another uncertainty for hydrogen is the regulation and end user attitudes (demand) on different hydrogen categories (green, blue, grey, red[7]).

## 6.5 Cost of electricity

At present the cost of produced electricity/hydrogen at Åland would be very high, taking into account the grid connection investments (either electricity or gas) so at present there is no business case. In Sweden there are plans, however, to reduce grid connection costs from offshore wind (Svensk vindenergi, 2021) by setting connection costs to Svenska Kraftnet. If the connection cost (approximately 50% of the investment) would be taken off from the investment, the profitability of offshore investments would improve greatly. This is again a regulatory decision.

## 6.6 Political and regulatory decisions

EU green strategy has been outlined. The actual implications for offshore wind power and green hydrogen are, however, yet to be seen in practice.

For hydrogen, the "empire", representing the old investments and players, are defending natural gas (methane, $CH_4$) approach via blue hydrogen, luring customer investments (Neste, 2021). Regulation has very high impact on timing and viability of Åland Offshore Wind.

Regulation in total, is both opportunity and risk, and is in the middle of change from RED II to RED III and Fit-for-55. The end-result of the changes is difficult to estimate.

## 6.7 Solar Energy

Solar energy is a future opportunity. Currently it is still about twice as expensive as onshore wind, but near to costs of offshore wind. Solar hydrogen LCOH based on PV LCOE and electrolyzer CAPEX in 2021, 2030 and 2050 is 81, 54 and 27 €/MWh (Vartiainen et. al., 2021).

## 6.8 Partners

From implementation point of view partners can be both opportunity and risk. Selection of correct partners will reduce risks tremendously and confirm investors. On the other hand, being locked into a wrong partnership can cause great problems. This can be addressed by thorough planning and high-quality contracts (e.g. share-holder agreements, etc.).

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[7] Green hydrogen produced by renewable electricity by electrolysis
Blue hydrogen produced from methane ($CH_4$) and carbon capture and storage (CCS)
Grey hydrogen produced from methane without CCS, and
Red hydrogen produced by nuclear electricity.

## 6.9 Onshore wind power

The demand growth of electricity is setting the steps in investments. At present, onshore is the cheapest wind power production method and should be considered as a serious contender. Technology development and grid regulation, however, create uncertainty and possible opportunity. Another impeding factor is the public opposition of development projects.

## 6.10 Timing

If looking at the process, timing is an important part of management of strategic options (see chapter 7). Mentioned uncertainties are reduced over time. The demand growth, end user purchase criteria, technology development, and regulation will change the profitability of the case by time. The options from decision point of view are either wait or execute with development of the investment in small steps.

The investments, in the end, will amount to billions of euros. The Wait option, i.e. to do nothing, will however, not increase the value of the sea areas. The Development option, refining the knowledge of uncertainties, would develop the asset towards value growth at some point (see Figure 7.1). On the other hand when initial development is finished, there is still a Wait option available.

# 7 Roadmap proposal

## 7.1 Strategic Options

A roadmap is about decision making. The first decision to take in the case of offshore wind in Åland, is about wait, cancel or proceed. Based on the research results of the opportunity, political will in EU, technology and market development and time, our proposal is to proceed to carrying out development activities. The simplified decision tree is shown in Figure 7.1.

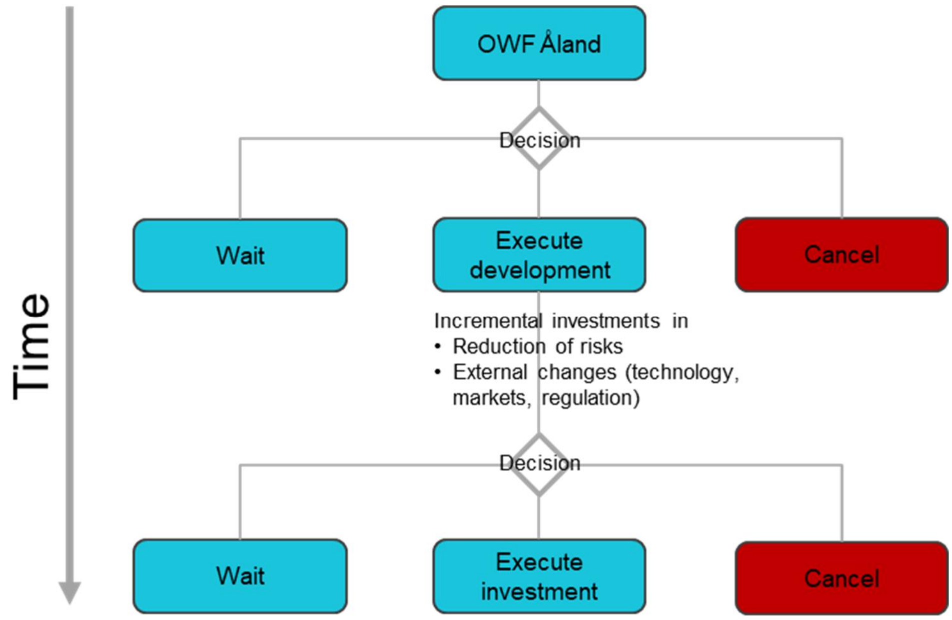


Figure 7.1. Development scheme.

The first part of the development work consists of the development of the wind farm F6 and possibly F4 combined. The arguments for this choice are large area and a possibility to build a lot of capacity, lowest grid investment costs (electricity, hydrogen), competing offshore development projects and possible shared benefits of a great increase of capacity of Fenno-Skan link between Finland and Sweden.

## 7.2 Financial grounds for the Offshore Wind Development

Windfarm investment is done in phases due to different needs:

- Skills required
- Uncertainties
- Equity structure, financing and return

The wind project development phase carries a major part of the risks. Therefore, it also includes the best returns. The return of development is defined backwards so that the value of a “shuffle ready” wind farm is defined by investor’s returns in investment and production phases. In reality, valuation is made at the time of the sale of the fully developed windfarm. This means that with declining investment costs and increasing production in time, the value of a windfarm goes up with time.

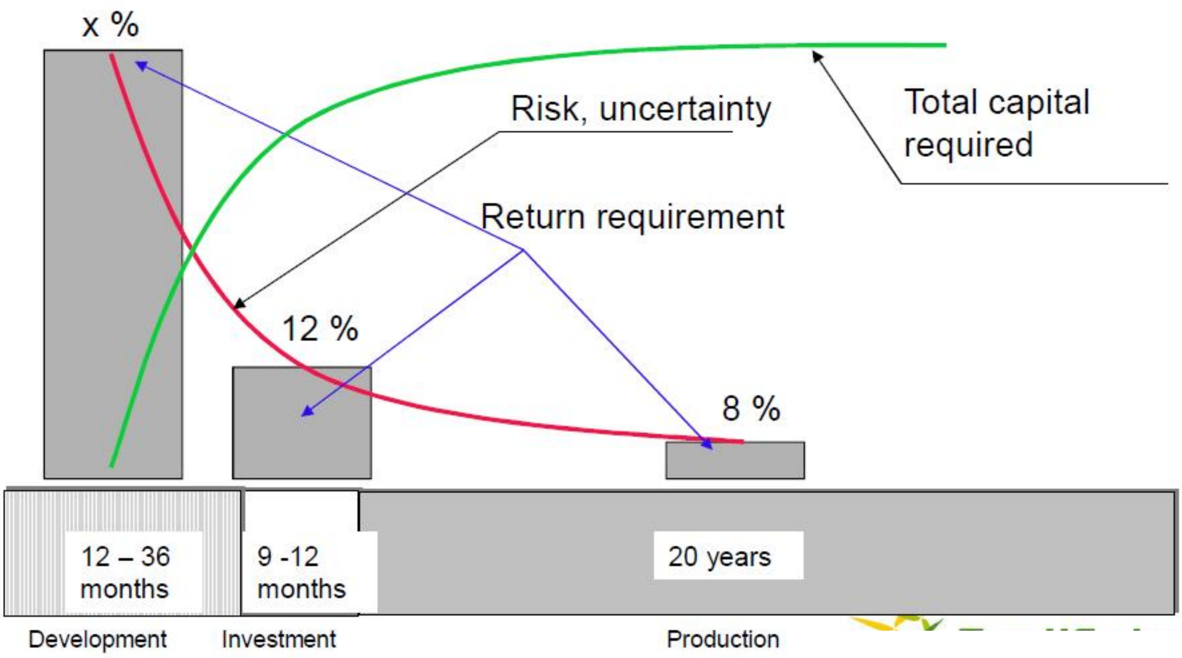


Figure 7.2. Phases of a wind power project (Pilli, 2016).

In the case of Åland Offshore Wind the development would take probably 3-5 years. The funding of the development phase could require approximately 5-10 MEUR. The multiple in return may vary between 5 – 20 times (25 – 200 MEUR) of the money invested to development. As the risks lie in the development phase; the development work must focus always on the larger uncertainties/risks.

### 7.3 Roadmap – Management of risks and earnings logic

In the beginning, focus should be on development of the offshore wind power and possible electricity PPAs[8]. Hydrogen and P2X products opportunities will be clarified later during the development phase. The development work should focus always on the largest uncertainty/risk on the list, like packed ice, to avoid unnecessary risks and development losses. Also, the required studies (environmental, visual, noise, etc.) must be made with highest possible quality to avoid delays in case of appeals in court.

The actual permitting process can be estimated to take 3-5 years. The finance for the development phase could be approximately 5-10 MEUR. By equity investment of 50% (2,5 – 5 MEUR) and proper shareholder agreements, Åland could keep adequate control in the development company. Adding debt finance, the equity requirement would be less.

The demand for electricity as well as hydrogen and P2X products will form and become more visible during the development period. A lot of offshore technology, both electricity and hydrogen, are under

[8] Power Purchase Agreements reducing investor risks by linking production and demand.

development. The uncertainties will decrease, and the opportunities will become clearer with time, see Figure 7.3.

Also, the regulatory environment as well as customer demand will clearly reduce the investment risk. The ultimate task for the wind farms development is to get building permits. When development is finished and building permits have validity the value of the asset (wind farm company) becomes reality and sellable to markets upon the owner's decision. The multiple in returns may vary between 5 – 20 times (25 – 200 MEUR) of the money invested to development.

By step-by-step approach there is no need to tie up financing for the whole period, but rather to increase it in increments.

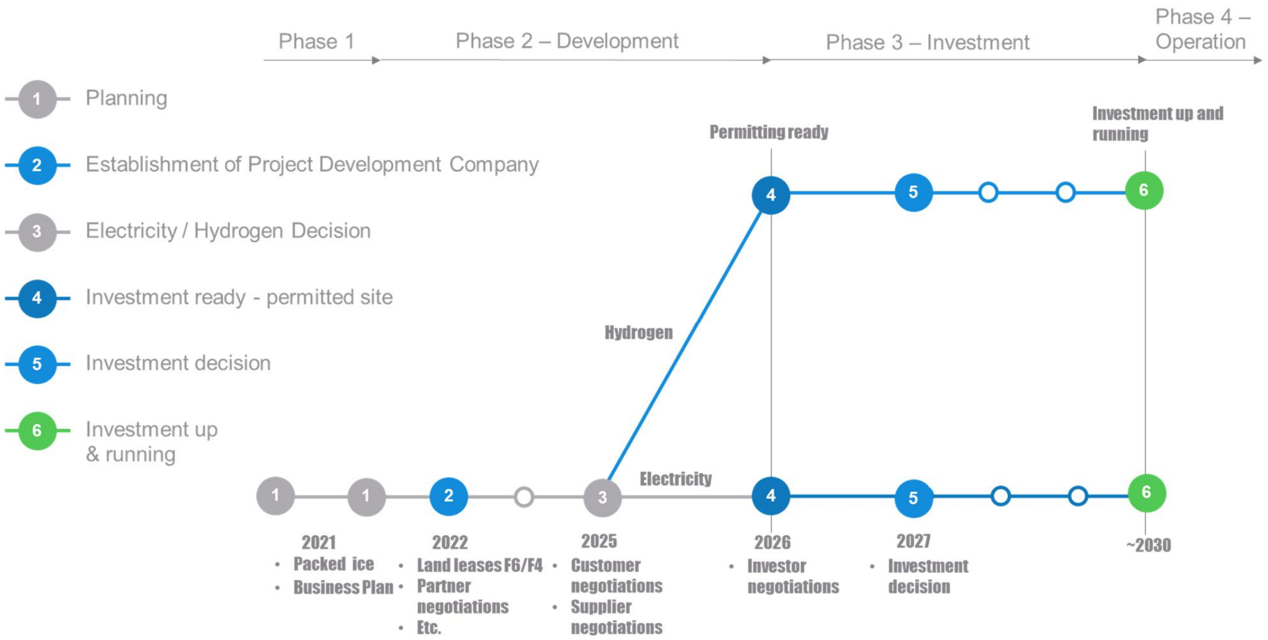


Figure 7.3. Illustration of the steps in road map.

## 7.4 Implementation of the Offshore Wind and Hydrogen Åland

The implementation proposal is based on following assumptions:

- estimated need for finance
- maximizing the value for Åland
- competencies and credibility required

The general planning of the proposed areas can be made done in parallel with steps 1 and 2.

Step 1: Preliminary studies and planning

- packed ice (leads to cancelling of the project if risk is real)
- general planning of the areas F6 and F4 (can go parallel with next step 2) wind farm development company business plan

        - tasks
        - timing
        - finance
        - partners
    - setting up the wind farm development company (wait/cancel if no equity investors interested or no approval from Åland parliament)

Step 2: Setting up project development company dedicated offshore wind Åland

- Setting up a company, equity commitments[9] approximately 5-10 MEUR
- Partner negotiations
    - Share holder agreements
    - Setting up the board and recruitment of key persons
- Operative offshore wind development up to building permits
    - Land leases of the areas F6 (and F4), option for the rest
    - Investor relations
    - Turbine suppliers
    - Planning and investigation of
        - Hydrogen
        - P2X (methanol, ammonia)
- Wait/cancel options can take place if some of the development matters arise during the process

## 7.5 Partner study

The development phase does not require a lot of funds compared with the investment phase. In the search of the partners for the development, the following criteria apply:

- references & knowledge (reduction of investor's risk, improved quality of development, improved valuation)
- interest / will (ease of co-operation, structural and timing risks)
- investment philosophy (ease of co-operation, structural and timing risks)
- position (impact on ministries in Finland and Sweden)

There are different types of partners, which were studied through in structured meetings, see Figure 7.4.

[9] Commitment means, that parties are committed to finance the development when additional finance is needed. So the total amount of 5-10 MEUR of the finance is needed in not the beginning.

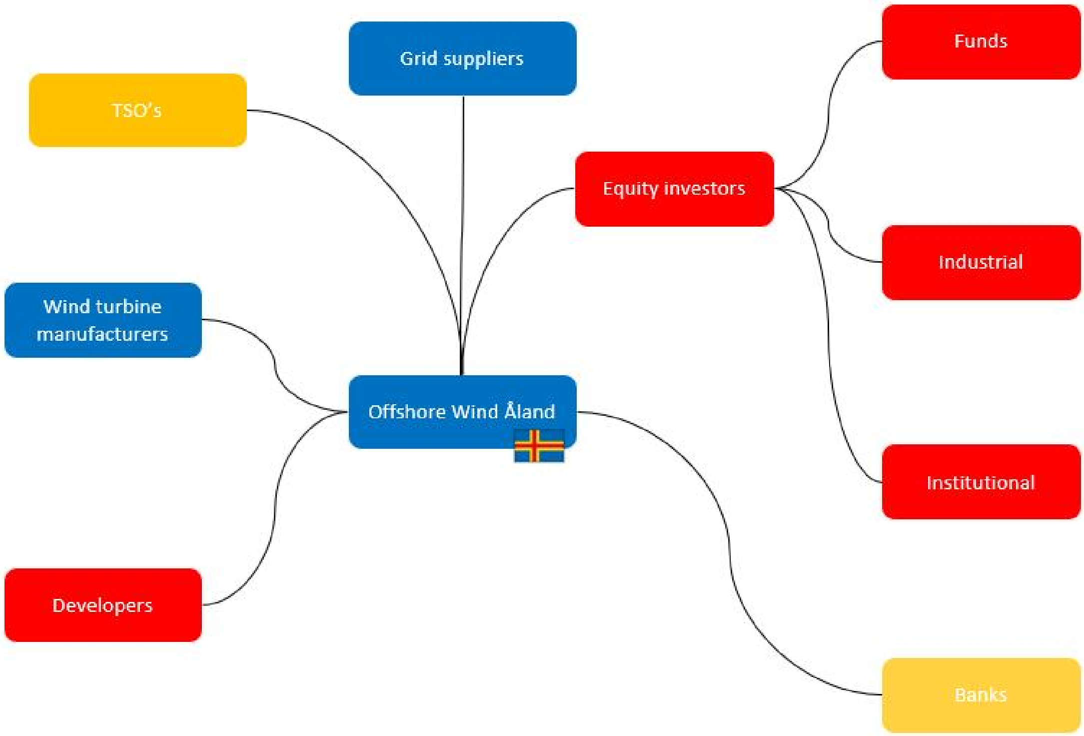


Figure 7.4. Partner categories.

Structured meetings based on the criteria mentioned above were arranged during the project with various international companies, representing the fields identified in Figure 7.4. Based on the discussions held, future partners for the development of the Åland Offshore Wind should have skills in:

- Marine construction (reduction of investor's risk, improved quality of development, improved valuation)
- Offshore wind and hydrogen regulation (reduction of investor's risk, improved valuation)
- Marine grid, substations (reduction of investor's risk)
- Electricity market
- Investors (improved valuation)

From national point of view, it would be beneficial to have companies from both Finland and Sweden.

# 8 Conclusions and Next Steps

The purpose of this study was to analyze offshore wind power future options for Åland sea area, covering the most feasible solutions for exporting of green electricity, feasibility of hydrogen production and transmission, alternative strategies, and steps for developing offshore wind-based business in Åland, as well as preliminary risk assessment and recommended next steps for Åland wind development.

The offshore wind production areas analyzed in the study, are in both the northern and southern side of Åland, covering 1000 $km^2$ in total.

The target of the interconnection study for transmission of electricity was to define the most feasible solutions in terms of the levelized cost of energy to connect the wind farms to the Nordic power system. Results indicate that the location and size of farms have a significant effect on the cost of interconnection. Costs vary from 15 to 34 €/MWh case by case. These costs do not include the generation costs.

Based on this study, the most feasible cases are in the northern side of Åland, wind farms F4 and F6. Wind generation capacity in these farms is approximately 4 GW at total with annual generation of 20 TWh. These Åland wind farms are in an area, where the farm connection could also provide a possible basis for interconnection of two power systems. The additional cost of a solution where energy transmission from wind farm could be done to both Finland and Sweden is approximately +5 €/MWh compared with the solution where wind capacity is realized only to one direction.

Transporting hydrogen in a pipeline is efficient and cost-effective, on a par with HVDC when only transmission costs are compared. However, the production of green hydrogen is challenging due to high electricity consumption and large investment costs, which tip the balance in favor of electricity transmission. Electrolyzer stack and equipment costs are expected to decrease in the coming years, but not so much that electricity price and conversion losses would be insignificant.

The competitive advantage of hydrogen could potentially be found in specific industrial plants, such as steel mills, chemical refineries and even pulp mills. If hydrogen is clearly the desired end-product at the destination, pipeline transmission is a realistic alternative to consider. Another potential asset of hydrogen is that minor amounts can be stored directly in the pipeline, which could help alleviate problems with energy availability on a short timescale (days, weeks). Excavated lined rock cavern storages can also be used if larger energy quantities need to be stored, for instance when long-term (week, month, seasonal) storage capacity is required. The lined rock caverns can be implemented in Scandinavia, where naturally occurring salt caverns or other formations are not as available as in elsewhere in Europe.

Offshore construction of pipelines is considered to be about twice as expensive as onshore. The challenging environment also carries a higher risk of cost overruns and uncertainty. However, there are only few technological challenges that have not been solved previously regarding the hydrogen sector. Offshore hydrogen production is one aspect that is currently being piloted in several different projects but has not been applied in industrial scale. There are no clear technological barriers which would completely prevent offshore hydrogen production, aside from issues related to scaling of technology.

There are several different cost elements which could be optimized to reduce the overall costs, but many of these only have a minor overall impact. Platform structures were associated with a large portion of the total costs in this estimation for both electricity and hydrogen pathways. The platform structures also have one of the highest perceived uncertainties regarding costs.

The opportunity for offshore wind at Åland is large, twice the size for instance Dogger Bank offshore wind farm in the North See, which is already under investment (Dogger bank, 2021). Production could exceed 30 TWh, which roughly equals 50% of the electricity production in Finland in year 2019[10]. Despite that the Dogger Bank investment is under construction, it should be emphasized that the investment profitability differs and is always case related (e.g. electricity price in UK vs. Finland/Sweden).

Financial calculations, discounted cash flow (DCF) etc. are not possible at this point. The investment costs of turbines were not in the scope of this study. The value of electricity and hydrogen are to be defined in the future. The elements of the financial calculation are moving targets within the time span (3-5 years) and will be fixed more precisely during the project development.

The approach towards offshore wind at Åland should be implemented in steps and reducing uncertainty for investment.

Proposed next steps are to 1) carry out preliminary studies and perform planning for 2) setting up a development company dedicated to offshore wind Åland. This approach is based on the estimated need for financing, maximizing the value and control for Åland, and the competencies required. The general planning or the proposed areas can be made done in parallel with steps 1 and 2.

The possibilities for production of hydrogen as well as P2X products like methanol and ammonia will become clearer during the development period and should be kept on the radar.

The main volume of the production can be achieved on northern side (F6 and F4). The wind areas F1-F3, F5 on the southern side should be followed similarly. The grid connection costs for the southern areas are, however, approximately double compared with the areas F6 and F4.

[10] 66 TWh, Energiateollisuus (3.1.2020)

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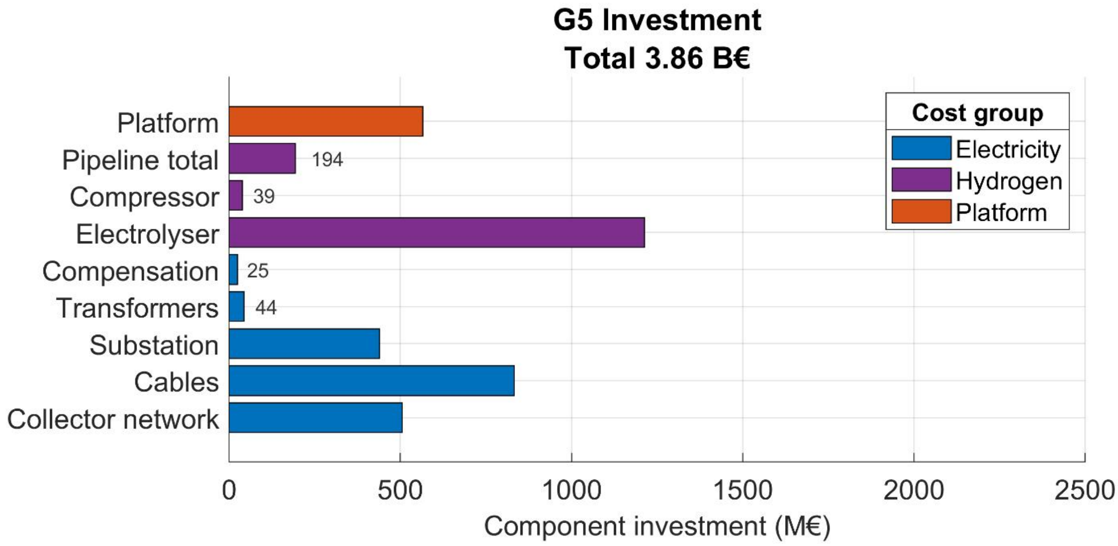
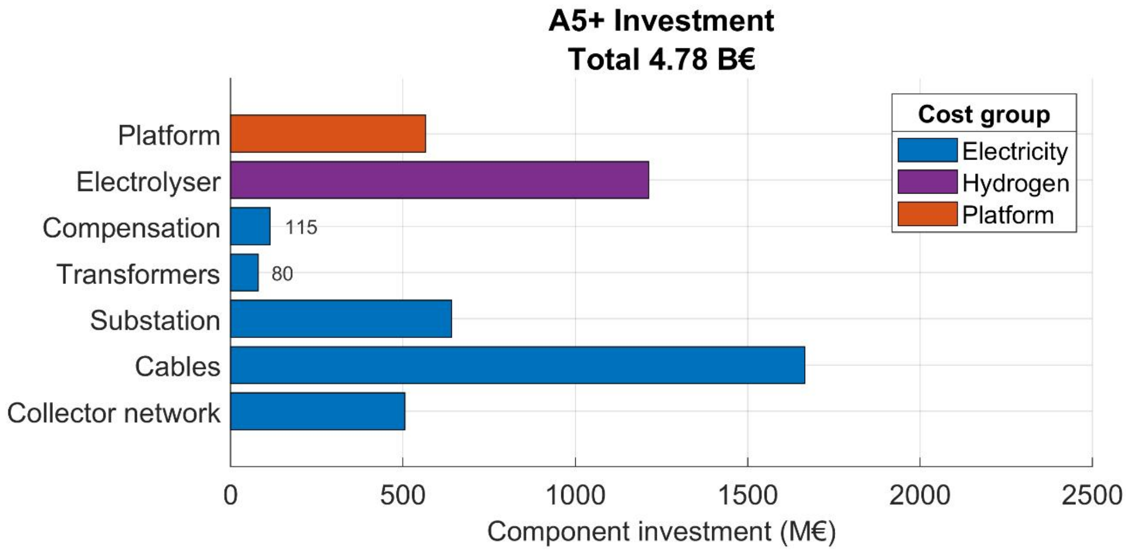
# Appendix I Parameters used in obtaining production profile

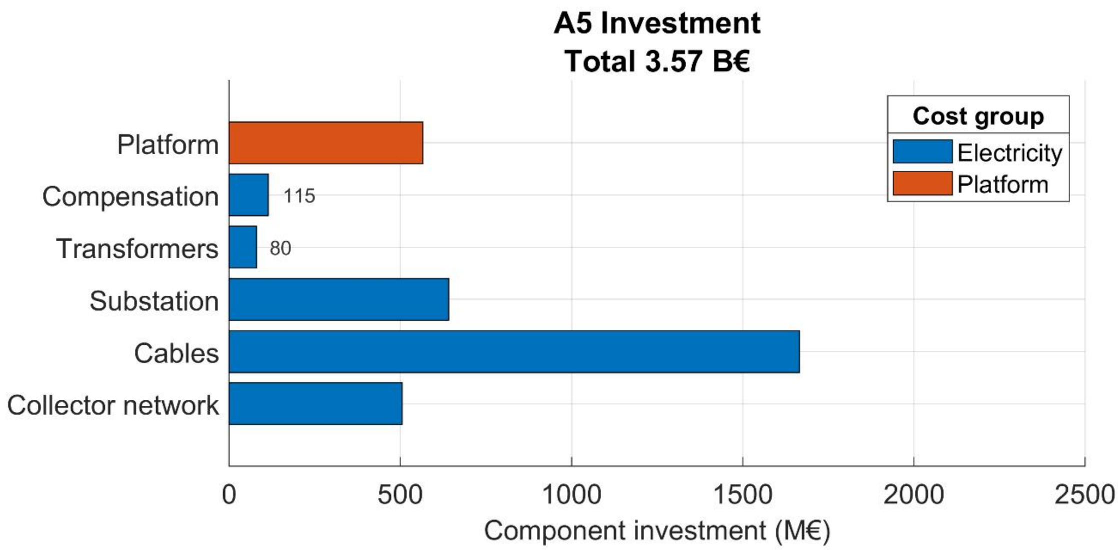
Table A1. Parameters used to obtain the annual production profile of the wind turbine in Renewables Ninja internet service. (Renewable Ninja)

| | |
|---|---|
| **Lat** | **60.601515** |
| **Lon** | 19.922932 |
| **Date starting** | 1.1.2019 |
| **Date ending** | 31.12.2019 |
| **Dataset** | merra2 |
| **Capacity (kW)** | 1 |
| **Turbine** | Vestas V90 2000 |
| **Hub height (m)** | 150 |

## Appendix II Cost distributions for hydrogen gas scenarios



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