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134

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Bothnian Bay Hydrogen Valley – Research report

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Abstract

Research Project: Bothnian Bay – Hydrogen Valley
Duration: 1.4.2021 – 31.10.2021
Client: Fortum / Staffan Sandblom, St1 / Riitta Silvennoinen
Site of Research: LUT University, Lappeenranta, Finland
Work Group at LUT: Hannu Karjunen, Jukka Lassila, Tero Tynjälä, Petteri Laaksonen, Mari Tuomaala, Julius Vilppo, Kimmo Taulasto, Janne Karppanen, Arto Laari, Antti Kosonen, Jero Ahola

This report is part of a commissioned research, ordered jointly by Fortum and St1. The research was carried out by LUT University between 1.4.2021 – 31.10.2021. The purpose of the study was to perform a hydrogen ecosystem analysis on a strategic level for the Bothnian Bay, describing the key customers, producers, and necessary infrastructural elements. The scope and detail level of the study was purposefully kept light to enable a rapid procedure. A key question of the work was whether local wind power resources would be enough to meet the increased electricity consumption, which was assumed to be escalated primarily by steel decarbonization and power-to-methanol systems. The conclusion of this report is that wind power potential is indeed sufficient for the transition, but extensive capacity additions are necessary – not only for the generation, but also for the energy transmission infrastructure. The future electricity demand presented in this work greatly exceeds some of the previously presented national public estimations, which indicates that the prevailing understanding of the opportunities and necessary development actions is deficient. The study found local differences in electricity transmission costs and wind resources, which can lead to competitive differences, and cause accumulation of investments to specific regions or countries. The results also indicate that chemical storages are likely needed for buffering hydrogen production and storing energy, but further analysis is required to assess the necessary volumes and optimal transport. It is proposed that the analysis is continued in more accurate studies, while also extending the scope to include Norway, Sweden, and Finland in their entirety.

Keywords: Hydrogen, Wind power, Electricity grid, Power transmission, Energy infrastructure

Tiivistelmä

Tutkimusprojekti:	Bothnian Bay – Hydrogen Valley
Kesto	1.4.2021 – 31.10.2021
Asiakas:	Fortum / Staffan Sandblom, St1 / Riitta Silvennoinen
Tutkimuspaikka:	LUT University, Lappeenranta, Finland
LUT Työryhmä:	Hannu Karjunen, Jukka Lassila, Tero Tynjälä, Petteri Laaksonen, Mari Tuomaala, Julius Vilppo, Kimmo Taulasto, Janne Karppanen, Arto Laari, Antti Kosonen, Jero Ahola

Tämä raportti on osa Fortumin ja St1:n tilaustutkimusta. Työ toteutettiin LUT Yliopistolla aikavälillä 1.4.2021 – 31.10.2021. Työn tarkoituksena oli tarkastella strategisella tasolla Perämeren alueen vetyekosysteemiä, kuvaten sen oleellisimmat asiakkaat, tuottajat ja vaaditut infrastruktuurielementit. Työn laajuus ja tarkkuustaso oli tarkoituksella kevyehkö nopean läpivientiprosessin varmistamiseksi. Eräs työn avainkysymyksistä oli tuulivoimaresurssien riittävyys suhteessa lisääntyneeseen sähkönkulutukseen, johon puolestaan vaikuttaa alueen terästuotannon muuttuminen hiilineutraaliksi ja sähköpohjaisten kemikaalien tuotanto (power-to-methanol). Johtopäätöksenä alueen tuulipotentiaalia voidaan pitää riittävänä muutosta varten, mutta käytettävissä olevan kapasiteetin on kasvettava merkittävästi sekä sähköntuotannon että energian siirtojärjestelmien osalta. Työssä esitetyt sähkönkulutuksen ennusteet ylittävät osan aiemmin esitetyistä kansallisista arvioista, jota voidaan pitää osoituksena puutteellisesta näkemyksestä alueen mahdollisuuksien ja kehitystarpeiden suhteen. Tutkimuksessa todetut alueelliset erot tuulisähkön potentiaalin ja sähkönsiirron kustannuksissa voivat heijastua paikallisena kilpailuetuna, sekä investointien kasautumisena tietyille alueille ja valtioille. Energian varastointiin ja vedyntuotannon tasaukseen tarvittaneen kemiallisia energiavarastoja, mutta kokoluokan ja kuljetusten tarkempaan arviointiin vaaditaan jatkotutkimuksia. Ehdotamme työn jatkamista tarkemmissa selvityksissä, joissa voidaan myös laajentaa tutkimusaluetta kattamaan Norja, Ruotsi ja Suomi kokonaisuudessaan.

Avainsanat: Vety, Tuulivoima, Sähköverkko, Sähkönsiirto, Energiainfrastruktuuri

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1 Introduction

Hydrogen is necessary element for achieving EU’s climate neutrality strategy. To satisfy the hydrogen demand, vast amounts of electricity are required compared to today’s demand. The role of hydrogen as a raw material and energy carrier is expected to grow rapidly in the future. Hydrogen will also be an important feedstock in the production of different hydrocarbons, replacing the use of conventional fossil products.

Regional ecosystems, or *hydrogen valleys*, are likely crucial for kickstarting the widespread development of hydrogen production and utilization. These regional ecosystems represent important hubs of industrial activity, and they will be major renewable electricity users. Finland has a few suitable candidates for such locations. For instance, the south-eastern part of Finland features a large concentration of pulp and paper industry. Additionally, the significant offshore wind potential around the Åland islands could enable various electrification schemes. Another potential ecosystem lies in the Bothnian Bay, which is being studied in this work.

1.1 The Bothnian Bay area

The Bothnian Bay area is known for the presence of heavy industry and renewable energy potential. The coastal area is long, and there are several ports serving the maritime sector. Biobased CO_2 is available in large amounts for example from the pulp and paper industry. Therefore, there is a great potential for the area to become globally important producer for carbon neutral steel, fuels, and chemicals. The map of the area with its 10 key locations is in Figure 1.

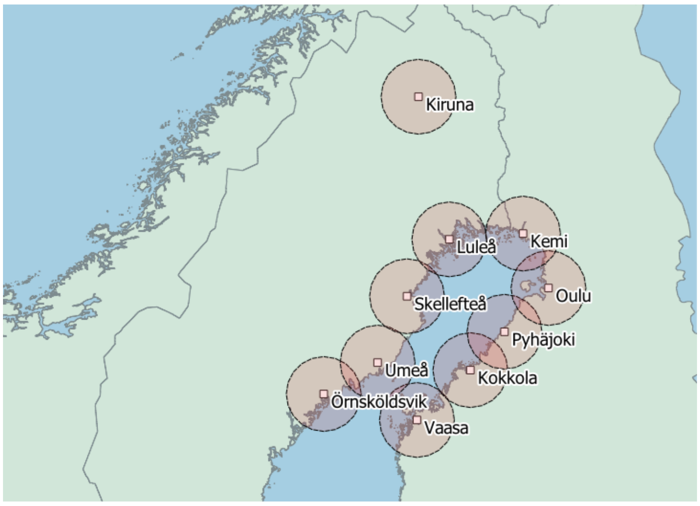

Figure 1 Studied area with 10 key locations highlighted.

1.2 Objectives and definitions

The objective of this work was to quantify and illustrate the opportunities related to the decarbonization of the Bothnian Bay area with a wide-spread utilization of green electricity, hydrogen and CO_2.

Critical research questions of this study will include the following:

- What is the potential for industrial hydrogen use as a feedstock, and what are the sectors using it?
- What is the potential for Power-to-X production assuming that all locally produced CO_2 is utilized and refined to methanol? Is it feasible to produce the required hydrogen quantities?
- How much renewable electricity production is planned in the area, and would that be enough to satisfy the local need?
- What are the main infrastructural requirements related to the electricity grid and pipelines?
- What is the scale of investments for enabling the transition?

The scale of hydrogen demand was estimated by studying the local industry and its CO_2 emissions. Furthermore, a quantification of onshore and offshore wind potential for different time scales was conducted to allow the estimation of hydrogen supply. The information from these surveys was then used to assess the impacts to infrastructure.

As the work progressed, it became reasonable to focus the study into steel industry's transformation. The scale of operations was assumed based on the current levels of activity, i.e., the possible future growth or decline of these industries was not considered apart from the public knowledge which was available at the time of the study.

Hydrogen will also be an important raw material in the production of different hydrocarbons, replacing the use of conventional fossil products. One such product is methanol, which can be utilized as a flexible platform for refinement into different specialized products – or even directly as an energy carrier.

2 Electricity demand caused by industrial decarbonization

The potential hydrogen use in the Bothnian Bay area was analyzed to find out the corresponding requirement for wind power production. The hydrogen need is a sum of a) hydrogen required as such in industrial processes and b) hydrogen required in methanol production to recycle the CO_2 emissions of the region. Main industrial sectors studied include forestry, steel, chemicals, and cement. Most of these industries are both potential hydrogen users and carbon dioxide emitters.

2.1 Hydrogen and electricity use

Currently, hydrogen is used globally in the chemical industry for various purposes, such as production of methanol and ammonia, or hydrogenation of different non-saturated hydrocarbons. In modern biorefineries, hydrogen is used for biodiesel production from biomass. At the moment, hydrogen is produced mainly by steam reforming from natural gas.

In the future, the role of hydrogen as an energy carrier is expected to grow. Various industrial uses for hydrogen are also possible. One major hydrogen usage is expected to be steel industry, where plans have emerged to replace coal in iron oxide reduction with hydrogen. Electrolytic hydrogen production route is expected to be the main method in the future. The drivers for the change are increasing CO_2 emission prices, reduction of electrolyser expenses, and low-cost electricity. The conversion from electricity to hydrogen in an electrolysis process is assumed to take 51 kWh/kg_{H2} of electricity in this work, corresponding roughly to 65% efficiency that is defined from the energy content of the electricity to the lower heating value of hydrogen.

2.1.1 Hydrogen and electricity consumption of steel industry

Sweden is one of the most prominent iron ore producers in Europe. At present, the majority of the iron ore is exported and not refined to crude steel in Sweden (Businesswire, 2020). The Kiruna mine, owned by the government-owned mining company LKAB, produces most of the ore. Another mine, Kaunisvaara, was active between 2012 and 2014, but operations were ceased as the mining company, Northland Resources, declared bankruptcy. Recently, Kaunis Iron AB has restarted the mining operations in the area.

The premise of this study is that the steel industry will decarbonize. In support of this notion, two estimates are presented for the hydrogen and electricity consumption of the steel mills. The high estimate assumes that all annually mined iron ore in Sweden would also be processed locally to direct reduced iron (sponge iron) using the SSAB's Hybrit process (SSAB, 2017). The electricity demand would amount to about 50 - 55 TWh/a with current mining quotas (Gebart, 2021, SSAB, 2021). At present, there would not be enough plants in the Bothnian Bay area to process all the mined iron ore to sponge iron nor to further process the sponge iron, but there are existing projects to increase the steel production capacity[1]. Electricity demand of the high estimate is summarized in Table 1.

Table 1. High estimate for steel electricity demand

Owner	Mill location	Location in Figure 2	Total electricity demand (incl. H_2 prod.) (TWh)	Hydrogen-related electricity demand (TWh)
Various	Various	Kiruna	51	51
Total (high estimate)			**51**	**51**

In contrast, the low estimate is based on converting only the existing blast furnaces in the area to the Hybrit process. Additionally, the low estimate includes 3.5 TWh electricity demand for the Tornio mill electric arc furnace (Tekniikka ja Talous, 2015). Table 2 shows the total electricity demand for the low estimate. These preliminary electricity demands could be made more specific and accurate if detailed information about the sites and processes would be available. Additionally, the low estimate is only based on existing major units in the area, so future plans and smaller units were not included.

Table 2. Low estimate for steel electricity demand.

Owner	Mill location	Location in Figure 2	Total electricity demand (incl. H_2 prod.) (TWh)	Hydrogen-related electricity demand (TWh)
SSAB	Raahe	Pyhäjoki	9	9
SSAB	Luleå	Luleå	8	8
Outokumpu	Tornio	Kemi	3.5	0
Total (low estimate)			**24**	**17**

[1] H2 Green Steel plans to produce five million tons of steel annually by 2030 in Boden-Luleå region.

Electricity demand in high and low estimates are shown together in Figure 2. The location of the electricity demand is divided according to existing steel mills in the low estimate, but projected to the closest key area of this work (e.g. Raahe mill is included in the Pyhäjoki region). In the high estimate, additional electricity demand is projected to the Kiruna region, where the iron mining activities occur, Naturally, the actual refining process could take place elsewhere.

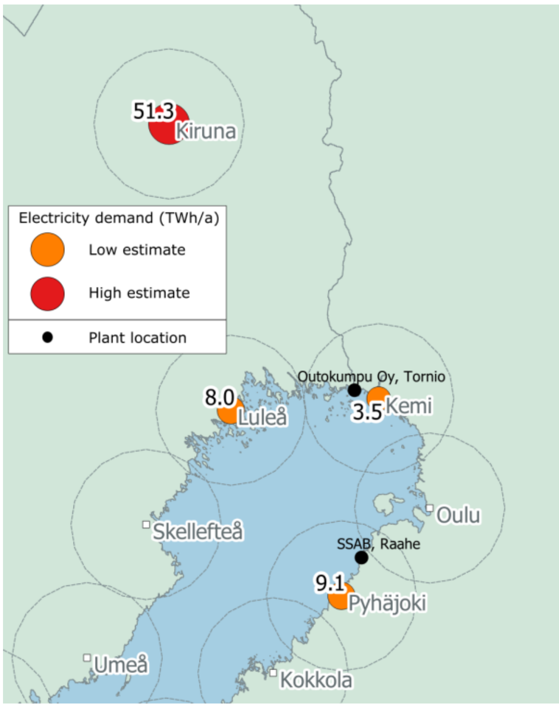

Figure 2. Steel electricity consumption (TWh/a) for low and high estimates.

2.1.2 Hydrogen consumption in methanol production

Besides hydrogen, methanol production requires CO_2. The electricity demand of the synthesis processes is low, and therefore it does not have a remarkable impact on total electricity demand.

In this work, the methanol production potential is based on the available industrial CO_2 in the region. The available emissions are estimated as described in section 3. If all the available emissions would be utilized for methanol production, about 8.6 Mt of methanol (47 TWh) could be produced. Correspondingly, about 85 TWh of electricity would be needed to produce the required hydrogen. The Kemi region represents a highly concentrated opportunity cluster for power-to-X production (Figure 3). In practice, probably only a fraction of the methanol potential would be practical to implement, limiting factors being: the actual need for methanol, availability and cost of electricity for hydrogen production, production of other Power-to-X products, etc.

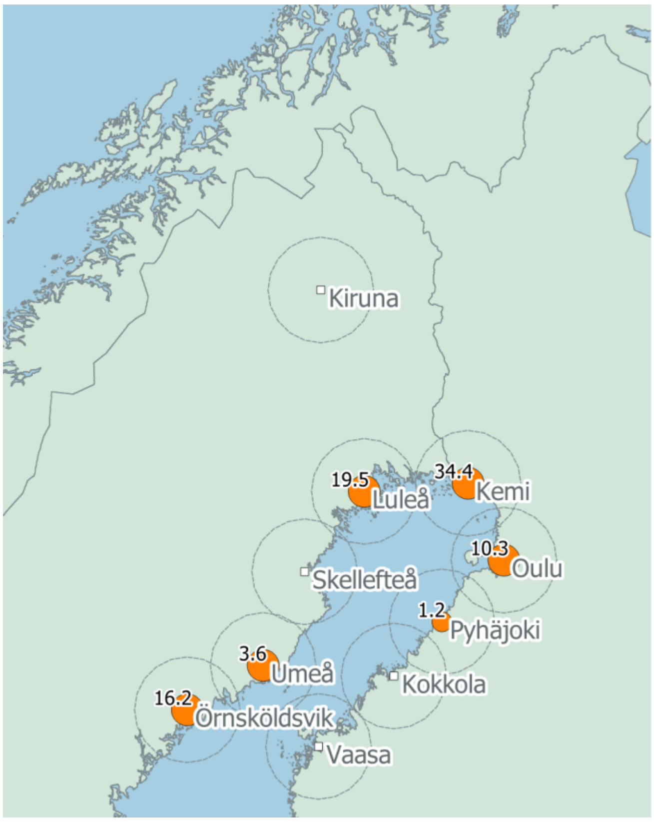

Figure 3. Electricity demand (TWh/a) for the potential of Power-to-methanol.

2.2 *Hydrogen infrastructure*

Hydrogen infrastructure can support and even replace current energy infrastructure components like electricity network, natural gas pipelines, and fuel transport logistics. The advantage of hydrogen over these other alternatives is that it can offer carbon-neutral ways to power various sectors. The disadvantage is that hydrogen infrastructure is more demanding and complex, mostly due to the chemical properties of hydrogen. The key points related to hydrogen infrastructure in this work are transportation and storage.

2.2.1 Hydrogen transportation

Pure hydrogen pipelines require embrittlement-resistant steel, which increases the costs relative to natural gas pipelines. Furthermore, larger pipe diameters are necessary (20% or even more) to achieve the same energy flow rate as with natural gas. Thus, the material costs for hydrogen pipelines could be 40% – 50% more costly compared to natural gas pipelines. Furthermore, the compressor is estimated to be 20% – 80% more costly for hydrogen (Ogden, 1999. Wang et al., 2020). In total, estimates for these cost escalations range from 10% (Saadi, 2018) to at least 50% relative to natural gas pipeline transportation costs (Ogden, 1999). Levelized transport cost of hydrogen in a pipeline is estimated to be about 0.17 – 0.25 €/kg_{H2} for 1000 km (Wang et al., 2020), which corresponds to about 5 – 7.5 €/MWh_{H2}.

Comparison of hydrogen transportation with electricity transmission makes more sense in cases where hydrogen is the desired product at the destination. Hydrogen production step introduces significant additional costs and losses, which should be acknowledged in the comparison. Several studies have found hydrogen pipelines to be cost-competitive with HVAC (High voltage alternating current) transmission (which is then coupled with electrolysis), especially when performed in submarine environments, with large capacities and long distances (Stiller et al., 2018. ERM, 2019. d'Amore-Domenech, 2021).

A recent report studied the implementation of an European-wide hydrogen gas network, which would be partially retrofitted from existing natural gas pipeline. For the whole 22 900 km network, pipeline costs were estimated as 17 – 28 B€, and compressor station costs between 10 – 36 B€ (Wang et al. 2020). Compressor station costs form thus quite significant portion of the total costs.

2.2.2 Hydrogen storages

Hydrogen storages will be required to balance the intermittency of renewable electricity production, especially from the wind, solar and other renewable electricity sources. Furthermore, industrial processes may not be adjustable, and therefore they require buffering and balancing of input streams such as hydrogen.

Finally, long term (seasonal) energy storage based on batteries is not feasible, necessitating the use of chemical energy storage. The scope of this work does not include estimations for the dynamic variability and storage requirements. Instead, a brief outlook on the technical alternatives for hydrogen storage are presented.

Hydrogen can be stored in large quantities in underground caverns. These can be naturally occurring formations, such as salt caverns or aquifers. However, aside from the Norwegian continental shelf, naturally occurring formations in Scandinavia are limited or nonexistent (IPCC, 2005). Fortunately, artificial caverns can also be excavated and used as gas storage. Manufactured tanks, such as pressurized steel tanks or cryogenic containers, are also applicable for smaller quantities. Hydrogen pipelines can also be used as a storage medium, with its capacity dictated by the maximum operation pressure, diameter, and length of the pipeline.

For instance, a 100 km pipeline with a diameter of 0.7 meters and a maximum pressure of 100 bars could store about 5 – 7 GWh of hydrogen.

Lined rock caverns could be implemented in regions where salt caverns or other natural formations are not readily available.[2] Given that these caverns can be very large, they represent one of the most cost-efficient methods of hydrogen storage. The excavated space is coated with concrete to smoothen the surface and act as a cushion between the natural rock and a steel liner, which in turn provides the gas-tight containment. A pilot for natural gas has been implemented in Skallen, Sweden. The capital cost of these lined rock caverns have been estimated to range from 56 to 116 USD/kg$_{H2}$. (Ahluwalia et al., 2019). The levelized cost of storage is highly dependent on the turnover, i.e. how much of hydrogen moves through the storage (or how many full/empty cycles it experiences during a year). If the capital expense is assumed to be 89 USD/kg$_{H2}$, the levelized cost (not including operational expenses) could be as low as 3 €/MWh (assuming a lifetime of 40 years with 5% interest rate, and 50 annual storage cycles) as demonstrated in Figure 4.

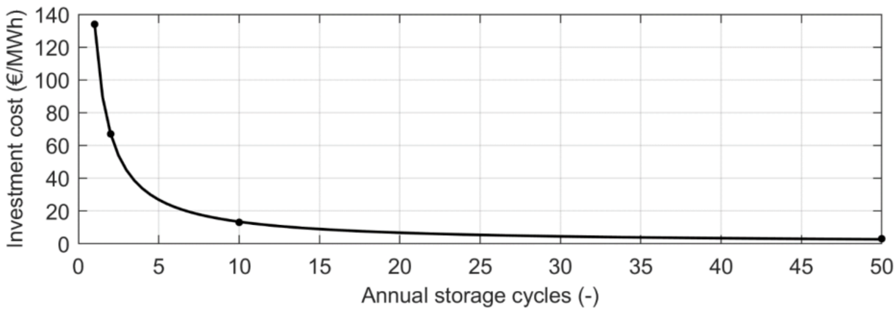

Figure 4. Levelized investment cost of a hydrogen storage as a function of the storage turnover (expressed as annual storage cycles)

[2] SSAB, LKAB and Vattenfall are building unique pilot project in Luleå for large-scale hydrogen storage

3 Carbon dioxide sources in the Bothnian Bay area

Industrial cluster in the Bothnian Bay area is the largest CO_2 emission source in the Nordic countries. CO_2 emissions are both fossil and biogenic. Largest fossil emitter is steel industry and biogenic emissions come mainly from pulp and paper industry.

It can be expected that the CO_2 emissions from the power sector will decrease in the future, as wind and solar power generation increases, and a larger portion of heat demand is covered by heat pumps. Seasonal heating demand could still partially rely on combustion, but capturing these emissions for utilization might not be cost-effective, given that the operational hours of these facilities is quite low.

Pulp and paper sectors produce mostly biogenic emissions that will probably become desirable for utilization purposes, especially if future legislation supports its use. Cement industry is likely to incorporate more renewable fuels (waste, biomass), and similar solutions may be observed in the power sector too.

3.1 Carbon dioxide utilization potential

Power-to-methanol production potential was calculated by considering the current total quantity of CO_2 emissions (biogenic and fossil) from pulp and paper mills, as well as from cement mills. The rationale is that these types of plants and industries are likely to still exist decades from now, with approximately the same capacity as today. It was also assumed, that minor changes (i.e. plant renovations, relocations, process modifications, capacity upgrades, old sites closing down, or new ones appearing) would not affect the result, and therefore they were left unnoticed.

Power sector was not included in the CO_2 potential, partly because these plants are likely to have lower annual operation hours and thus higher capture costs. This does not necessarily mean that there would not be any power production units equipped with CO_2 capture at all, but rather that they would be less common than industrial process sites with capture devices. For the sake of simplicity, the power sector was therefore completely neglected from CO_2 potential in this study.

There are several factors, which make the prediction of future CO_2 sources difficult without a detailed energy system model, and this was not the focus of this work. Furthermore, CO_2 emissions from individual sites and mills can also originate from multiple different boilers and units, which may not all be techno-economically feasible to equip with CO_2 capture. This would in practice result in a lower CO_2 quantity for utilization, but this level of resolution was not taken into account in this work.

Table 3 and Figure 5 show the total emissions and their distribution in the region (E-PRTR, 2017). The presented numbers include the planned new Metsä Group pulp mill in Kemi (estimated 4.5 Mt_{CO2}/a), although it is scheduled to be online not until late 2023. Additionally, the recently closed Veitsiluoto pulp mill emissions (1.3 Mt_{CO2}/a) have been excluded. Some industrial complexes, such as the Raahe steel mill, are classified into multiple separated entities in the data (i.e. power generation and industrial manufacturing each have their own emission numbers). Table 4 lists the largest CO_2 emitters in the area.

Table 3. Total CO_2 emissions from the region. (Adapted from E-PRTR, 2017)

Industry	**Biogenic (kt)**	**Fossil (kt)**	**Total (kt)**
Cement	**-**	**403**	**403**
Power	1 844	5 677	7 520
Pulp	**10 721**	**622**	**11 343**
Steel	1	3 758	3 759
Total	12 566	10 459	23 025
Power-to-methanol potential	**10 721**	**1 025**	**11 746**

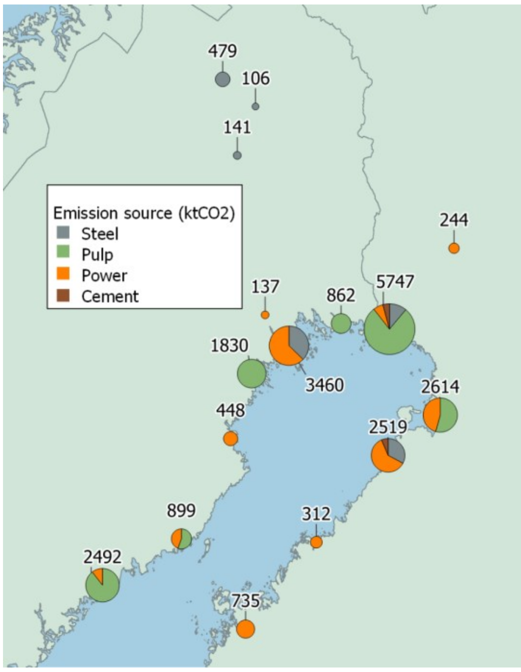

Figure 5. Total emissions by industrial activity (Adapted from E-PRTR, 2017).

Table 4. Largest point sources of CO_2 in the area (adapted from E-PRTR, 2017)

Company	**Country**	**Activity**	**Total kt_{CO2}**	**Fossil kt_{CO2}**	**Biobased kt_{CO2}**
Kemi new biofuel plant (2023)	FI	Pulp	4500	245	4255
~~Metsä Fibre Oy Kemi~~	~~FI~~	~~Pulp~~	~~3110~~	~~128~~	~~2982~~
Lulekraft AB	SE	Power	2170	2170	0
Metsä Board Sverige AB	SE	Pulp	1690	64.8	1625.2
Raahen Voima Oy	FI	Power	1530	1530	0
STORA ENSO OYJ, Oulun tehdas, Oulu	FI	Pulp	1420	238	1182
SSAB EMEA AB	SE	Steel	1290	1290	0
Smurfit Kappa Kraftliner Piteå AB	SE	Pulp	1130	10.1	1119.9
OULUN ENERGIA, Toppilan voimalaitokset	FI	Power	887	532	355
BillerudKorsnäs Sweden AB Karlsborg Bruk	SE	Pulp	862	9.4	852.6
SSAB Europe Oy, Raahen terästehdas	FI	Steel	828	828	0
Vaskiluodon Voima Oy	FI	Power	735	480	255
SCA Munksund AB	SE	Pulp	700	18.4	681.6
Outokumpu Oy, Tornio	FI	Steel	640	640	0
Domsjö Fabriker AB	SE	Pulp	540	4.7	535.3
SCA Obbola AB	SE	Pulp	501	31.5	469.5
Luossavaara-Kiirunavaara AB	SE	Steel	479	479	0
Umeå Energi AB	SE	Power	398	73.5	324.5
Tornion Voima Oy, Röytän voimalaitos	FI	Power	365	268	97
Boliden Mineral AB	SE	Mineral	275	274	1
Övik Energi AB	SE	Power	262	42	220
Napapiirin Energia ja Vesi Oy, Suosiolan voimalaitos	FI	Power	244	99.4	144.6
SMA MINERAL OY, Röyttän Kalkkitehdas	FI	Cement	242	242	0
Kokkolan Energia Oy	FI	Power	207	182	25
LAANILAN VOIMA OY	FI	Power	187	142	45
Skellefteå kraft AB	SE	Power	173	26	147
NORDKALK Oyj Abp, Raahe	FI	Cement	161	161	0
Luossavaara-Kiirunavaara AB	SE	Steel	141	141	0
Bodens Energi AB	SE	Power	137	48	89
OULUN ENERGIA OY, Laanilan ekovoimalaitos	FI	Power	120	60.7	59.3
Luossavaara-Kiirunavaara AB	SE	Steel	106	106	0
Kokkolan Energia Oy, Ykspihlajan	FI	Power	105	22.9	82.1

3.2 CO_2 transport and storage

Over 6200 km of CO_2 pipelines have been built in the United States alone (Dooley et al., 2009), so the technology is mature and well understood. The operation pressure of CO_2 pipelines is typically 85 – 150 bars. Natural gas pipelines typically have a lower pressure range of 60-80 bars. The critical pressure of CO_2 is 73.8 bars, which is why higher pressures are preferred:

when operating slightly above the critical point, there are less risks with multiphase flows and sudden fluctuations in thermodynamic behavior.

The same kind of carbon grade steel can be used for CO_2 pipelines as for natural gas pipelines, but thicker walls are necessary due to increased pressure (Duncan and Wang, 2014). Pipeline material costs typically make up only about 20 – 40% of the total investment, so the overall effect on levelized cost of transport is quite moderate. The levelized transport cost estimates for CO_2 pipeline in onshore applications range from 1.5 €/t_{CO2} to about 17 €/t_{CO2}.

CO_2 can be stored as a pressurized gas in various artificial or natural containers, or as a refrigerated liquid. Much like hydrogen, CO_2 can also be buffered to a pipeline, which could help with balancing of synthesis processes. This effect would probably be even more potent when both hydrogen and CO_2 are transported in a pipeline to a processing site, so that both feedstocks have some buffering capability. Investments in capturing, transport, and storing are, however, excluded in this study.

4 Wind energy production potential

The data for this section is gathered from the Finnish Wind Power Association (Suomen Tuulivoimayhdistys, 2021), County Administrative Board of Västra Götaland County (VBK, 2021) and The Norwegian Water Resources and Energy Directorate, (NVE, 2021).

The current status of wind power in the Nordic countries is constantly evolving. For a comprehensive understanding of the wind power status, another report could be written solely focusing on that topic. Thus, the analysis performed within the scope of this project is not very extensive. The data collected from the various sources can contain some inaccuracies. For instance, the number of turbines may be given but the total capacity or production missing or vice versa, the project status classification can vary between countries, and the location of the capacity may be distorted.

4.1 *Existing wind capacity*

For Sweden, a large portion of the existing capacity is focused in the SE2 region around Örnsköldvik as is evident from Figure 6. Another clear concentration is betweel Luleå and Skellefteå. On the Finnish side, the Pyhäjoki region represents one of the Finnish wind power clusters.

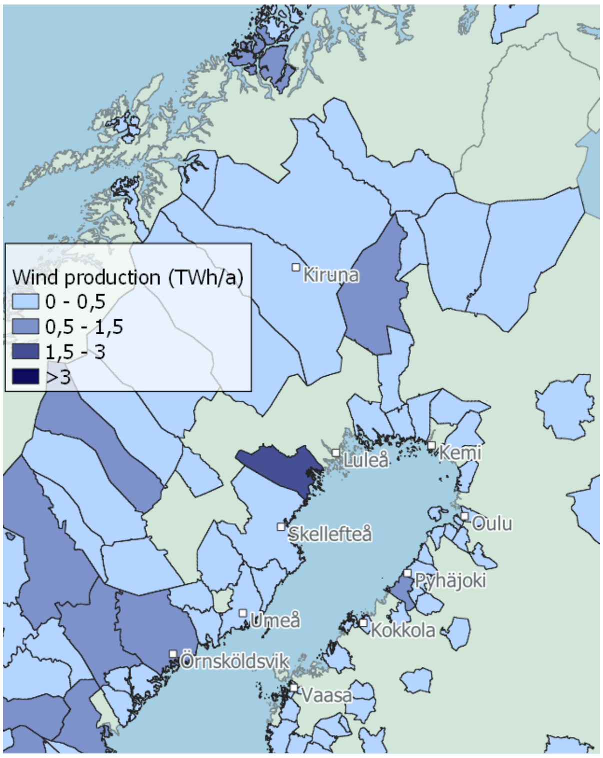

Figure 6. Existing and commissioned wind turbine capacity.

4.2 Future wind energy potential

For upcoming capacity, largely the same regions are in focus as with current capacity. For Finland, more regions are being planned inland around the latitude of Vaasa-Kokkola, as well further up north in Kemi region (Figure 7). The northern part of Sweden has numerous projects which have a status of "postponed or cancelled" (Inte aktuellt eller återkallat), or as having an ongoing appeal process (Figure 8). This partially explains why there are seemingly few wind sites visible in northern Sweden in Figure 7.

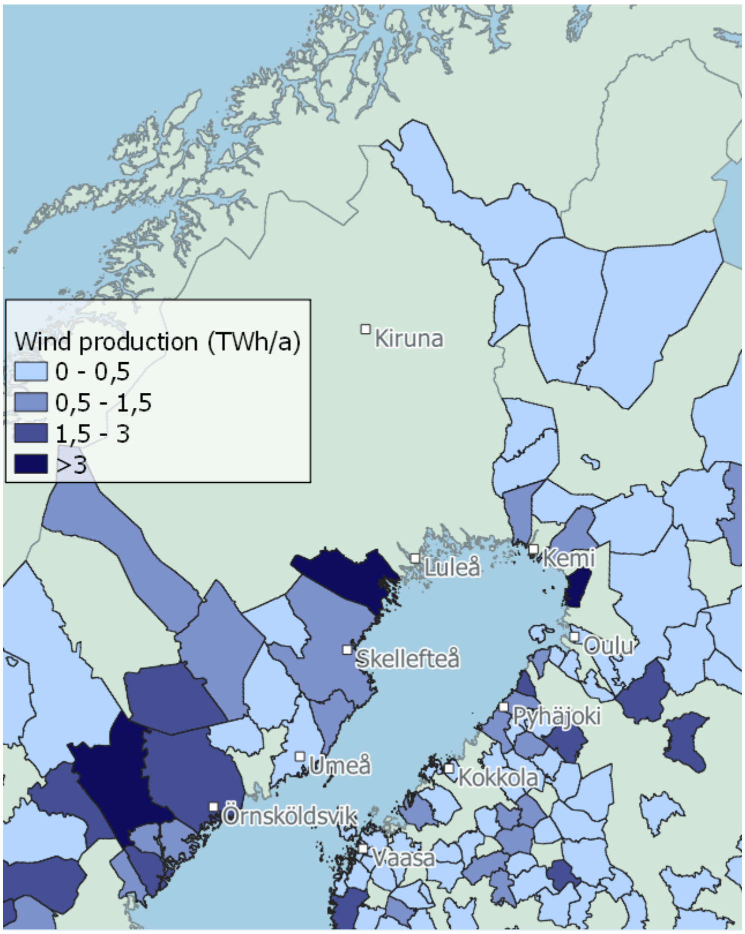

Figure 7. Approved sites for Sweden, and sites classified as under planning for Finland (includes projects from various stages from preliminary identification to construction).

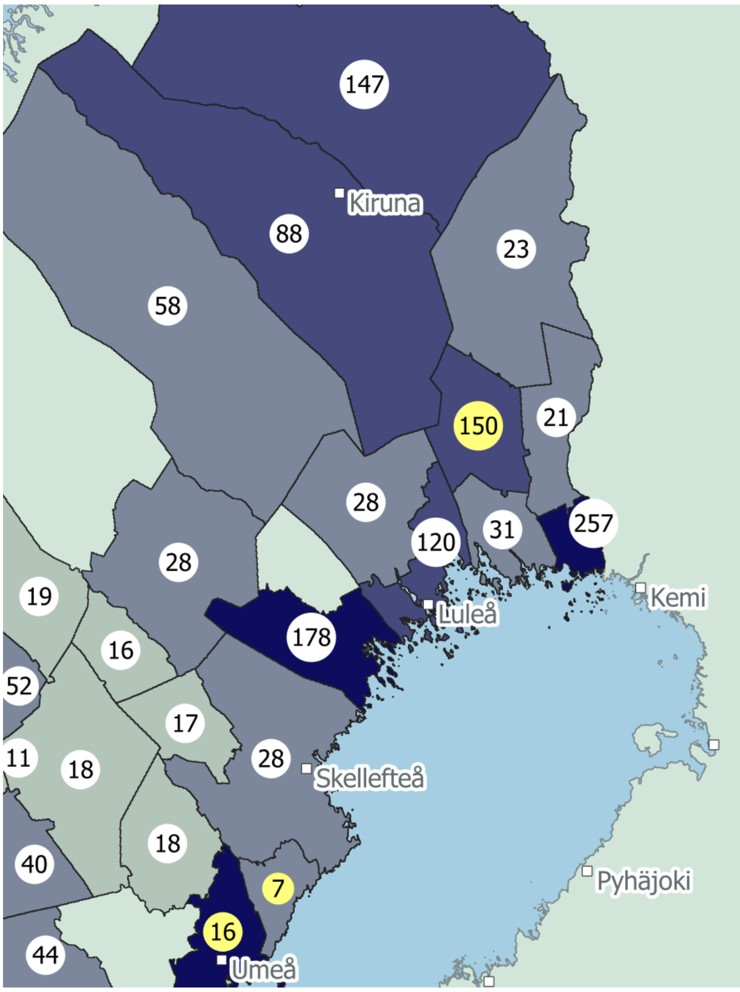

Figure 8. Number of wind turbines in municipality in Sweden which are classified as “postponed or cancelled” (white background), or in an appeal process (yellow background)

Especially the SE2 region (see Figure 9) is in an important role for providing large amounts of renewable electricity for the country. A strategic question then arises whether these renewable electricity resources are directed to south, where a large portion of population and consumption resides, or to the north, where large industrial users are located. Similar dilemmas are also present on the Finnish side, where large industrial clusters would require the power production from neighboring regions.

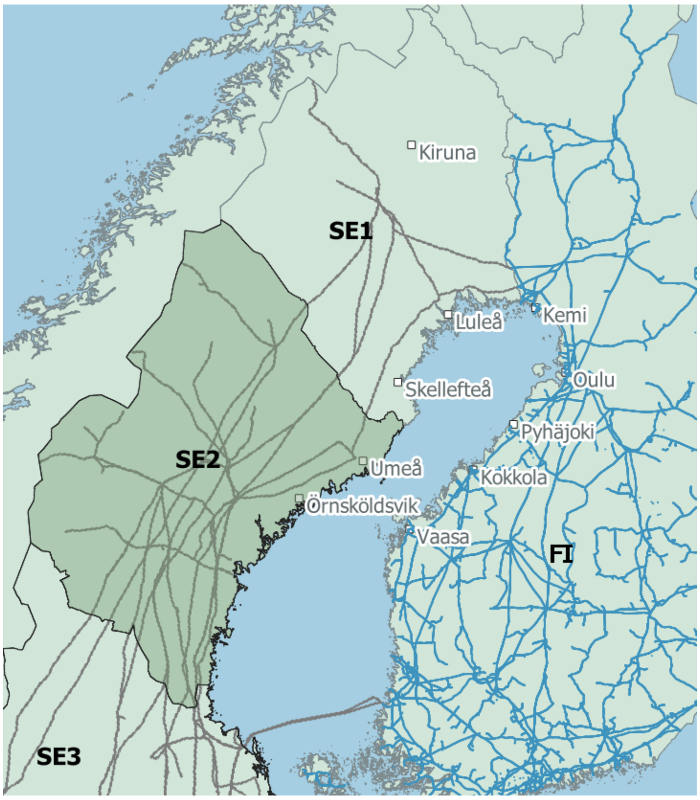

Figure 9. Existing main power transmission lines and market areas. Only 400 kV transmission lines are shown for Sweden.

A summary of the wind power capacities is presented in Table 5. The methodology for the long-term wind capacity estimation is presented in Chapter 5.

Table 5. Estimates for wind power capacity and production in the Bothnian bay region.

Timeframe	Country	Cumulative capacity (GW)	Annual production (TWh)
Existing	SE	4.7	11.5
	FI	2.2	5.5
	Total	**7**	**17**
Short-term	SE	11 – 19*	19 – 37*
	FI	18**	41**
	Total	**29 – 37**	**50 – 78**
Long-term	SE	11	31
	FI	28	87
	Total	**39**	**118**

* Assuming that all new commissioned turbines have an average size of 6 MW (number of turbines is estimated from data of approved sites)
** Assuming nearly all planned projects are realized

5 Interconnection of wind power

This chapter presents the results of interconnection study of wind farms. The target is to define estimation of interconnection cost regarding Bothnian Bay area wind farms. Due to large case area, study has not been done in detailed level, which means that the information of individual wind farms is not analyzed, but rather the focus is in larger ensemble. Results indicate that the location and size of wind farms have a significant effect on the cost of energy transmission. The study takes advantage of several references which focus on onshore and offshore wind network connection.

Due to nature of the study, analyses are done in strategic level. Connection and network solutions of individual turbines and offshore substations are not planned in detail, nor is route planning performed. In the study, several assumptions take place in the analyses. The most relevant are listed next.

1. Wind farms, wind turbines and wind conditions
    - All wind farms inside the same case area are equal regarding wind conditions (the same full load hours and the same generation profile). Different case areas may have different full load hours, and this has been taken into account (full load utilization time in Table 6)
2. Network and components
    - Capacity of the network is dimensioned based on maximum nominal power of wind turbines and wind farms
    - HVAC is used as interconnection technology due to relative low distances in offshore cases
3. Power system (TSO)
    - Assumption is that all wind farms (power capacity) can be connected to power system (Finland or Sweden or both)
    - Interconnection costs defined in the study do not include possible system level costs in power system. In the report, high voltage lines and export cables from wind farm to transmission system (TSO) are defined with shortest distance
4. Analyses in overall
    - Reliability (and outage costs) of turbines and electricity network has not been taken into account from the perspective of electricity not delivered due to interruption (only in maintenance costs)

Figure 10 presents onshore wind power case areas in Bothnian Bay area in Sweden and Finland used in the study. Colors in map indicate region based estimated wind power capacity in

2020–2025. Case areas are formed by using single region or combining two or more regions together.

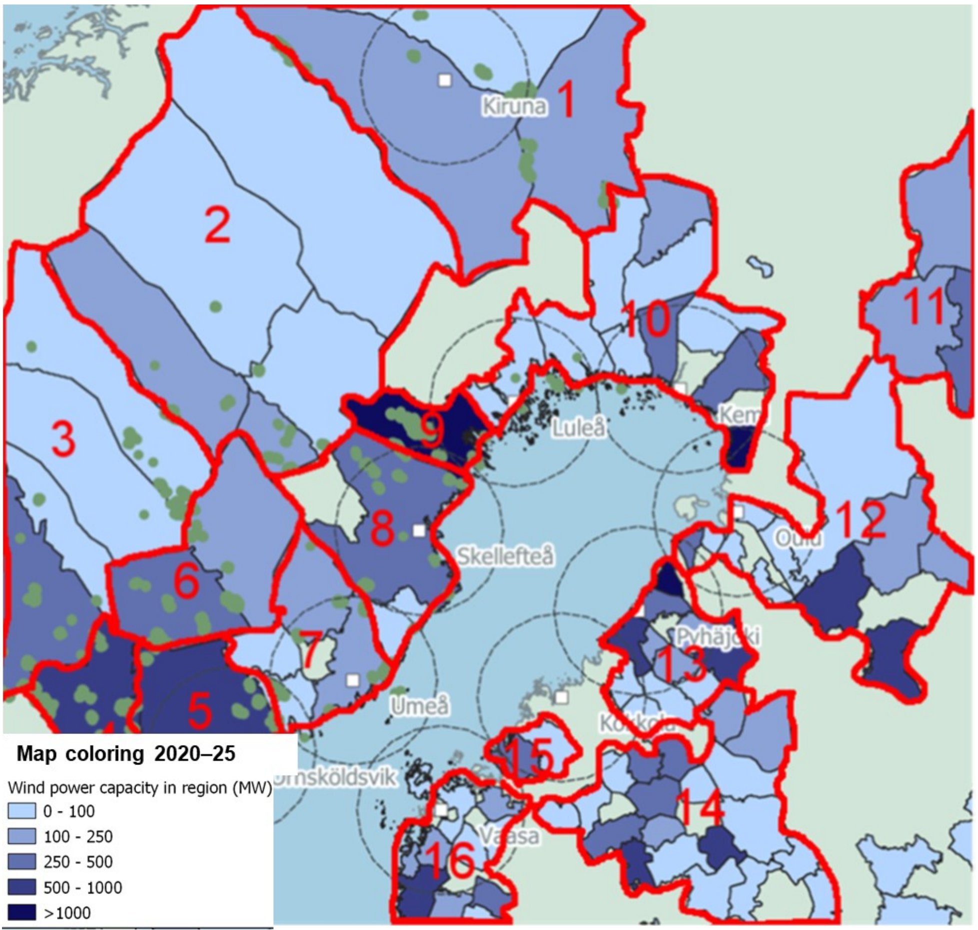

Figure 10 Wind power case areas in Bothnian Bay area in Sweden and Finland.

Table 6 presents the area specific data obtained from Figure 10. *Distance to consumption* indicates average transmission distance from the case area to the bay area consumption. The result is not an optimal connection route, but more like preliminary estimation of distance for transmission network. In addition to transmission distance, *peak power* of the generation, *mean capacity factor*, *full load utilization times* and *annual produced electricity* are presented.

Table 6 Wind power area -specific background data.

Area	Consumption location	Distance to consumption (km)	Power (MW)	Mean capacity factor (%)	Full load utilization time (h)*	Energy (TWh/a)
1	SE-Kiruna	80	600	29,7	2 602	1,6
2	SE-Umeå	300	800	28,8	2 523	2,0
3	SE-Örnsköldsvik	240	800	30,8	2 698	2,2
4	SE-Örnsköldsvik	90	1 200	29,8	2 610	3,1
5	SE-Örnsköldsvik	40	1 000	31,2	2 733	2,7
6	SE-Örnsköldsvik	130	750	30,3	2 654	2,0
7	SE-Örnsköldsvik	100	700	31,3	2 742	1,9
8	SE-Umeå	120	600	31,3	2 742	1,6
9	SE-Luleå	80	1 500	31,3	2 742	4,1
10	FI-Kemi	90	3 450	31,5	2 755	9,5
11	FI-Kemi	200	1 000	33,2	2 908	2,9
12	FI-Oulu	120	3 600	33,2	2 908	10,5
13	FI-Kemi	250	5 150	34,7	3 040	15,7
14	FI-Keski-Suomi	250	5 850	34,0	2 900	17,0
15	FI-Pyhäjoki	110	600	36,1	3 158	1,9
16	FI-Kemi	450	2 900	37,4	3 276	9,5
17	FI-Sea 1	40	2 340	39,5	3 460	8,1
18	FI-Sea 2	25	2 230	44,9	3 930	8,8
19	FI-Sea 3	20	840	42,5	3 720	3,1
20	SE-Sea 4	30	2 900	40,0	3 500	10,2

Due to high generation capacity in the case areas, existing electricity infrastructure has been neglected in the study, and all interconnection alternatives are based on new infrastructure. In offshore cases, network (cables) are planned to be subsea (submarine) type. Wind turbine costs (platform and wind turbine) are excluded from all numbers in this chapter.

As a basis for defining costs for interconnection of onshore wind power, structures of Figure 11 are applied in the case areas.

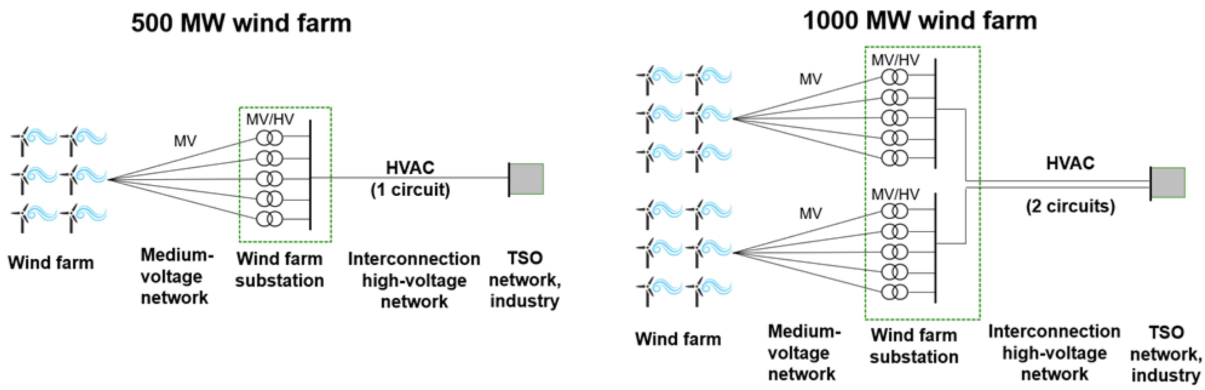

Figure 11 Principles of interconnection of onshore wind farms

Two basic onshore wind farm cases are applied; a) 500 MW and b) 1000 MW. The life-time costs of interconnection has been defined for these two alternatives, and they are scaled up depending on the size of the actual wind farm case in the Bothnian Bay area. Interconnection costs (€/MWh) depends strongly on distance, power (reserved transmission capacity), and wind conditions (full load utilization time) of the case area. In Figure 12, the influence of transmission distance to the costs of interconnection has been illustrated. Due to different unit costs of network components in Finland and Sweden, the results are illustrated separately. Background colors indicates the range of transmission distances from wind farm case areas to the Bothnian Bay coast area. Dotted lines indicate the average of the transmission distances.

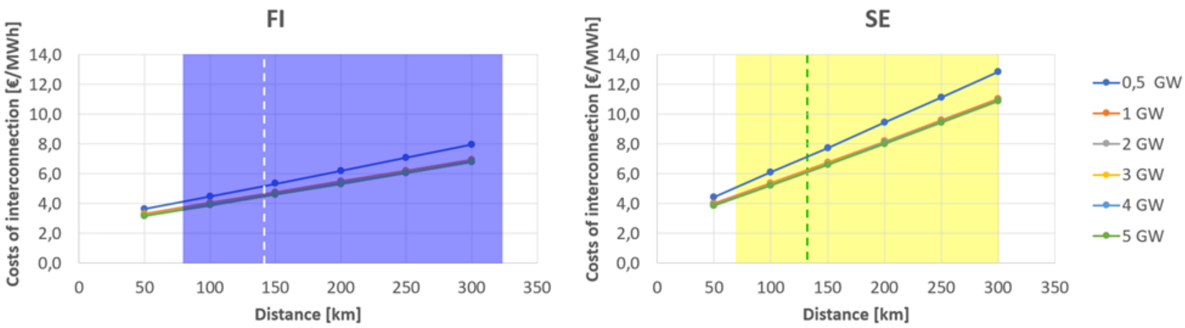

Figure 12 The dependency between transmission distance and interconnection costs in Finland and Sweden for various power levels

Figure 12 that interconnection costs vary from 4 €/MWh to 12 €/MWh depending on distance, transmission power, and unit costs of network components (Finland vs. Sweden). Due to scalability principles (for instance 2 GW wind farm interconnection = 2 x 1 GW wind farms interconnections), the costs for 1 GW, 2 GW, 3 GW etc. interconnections are the same when only specific costs are considered (€/MWh). For this reason, the cost curves of multiple gigawatt-interconnections are overlapping. Figure 13 illustrates the impact of the wind conditions (full load utilization time in both countries) of the case area to the interconnection cost.

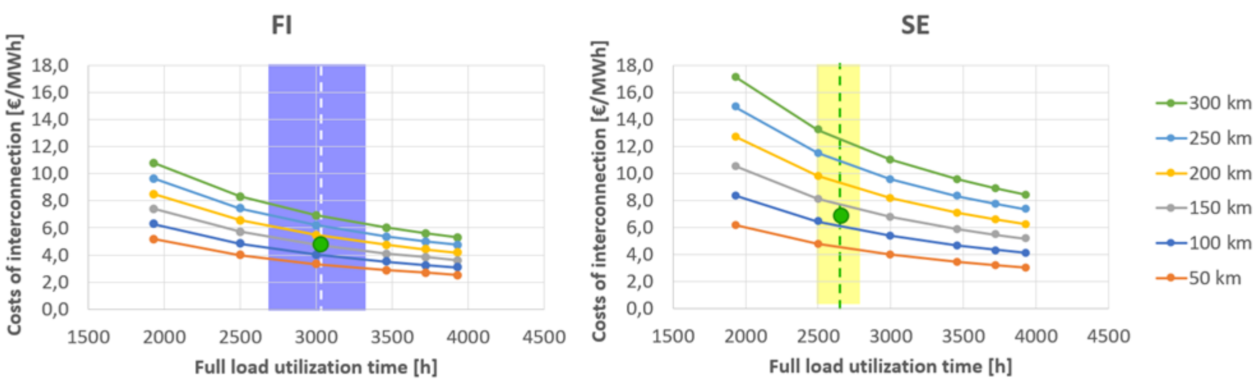

Figure 13 Effect of full load utilization time to the costs of interconnection in Finland and Sweden

It can be seen from the Figure 13 that wind conditions have significant effect on the costs. For instance, in low level wind condition areas (full load utilization time 2000 h/a), the cost of interconnection is for 1 GW wind farm with transmission distance of 150 km about 7.5 €/MWh, whereas high level wind condition environment (4000 h/a) provides for interconnection costs under 4 €/MWh. The full load utilization time varies in the case areas from 2500 to 3200 h/a in onshore wind farms, and from 3500 to 4000 h/a with offshore wind farms (Staffell et al., 2016. Pfrenninger et al., 2016). Tables 7 and 8 show a summary of the interconnection costs.

Table 7 Area-specific background data with corresponding interconnection costs per unit (€/MWh), annual cost (M€/a) and lifetime cost (M€).

Area	Consumption location	Distance to consumption (km)	Power (MW)	Mean capacity factor (%)	Full load utilization time (h)*	Energy (TWh/a)	Interconnection cost [€/MWh]	[M€/a]	[M€]	
1	SE-Kiruna	80	600	29,7	2 602	1,6	5	8	195	
2	SE-Umeå	300	800	28,8	2 523	2,0	13	26	656	
3	SE-Örnsköldsvik	240	800	30,8	2 698	2,2	11	24	594	
4	SE-Örnsköldsvik	90	1 200	29,8	2 610	3,1	6	19	470	
5	SE-Örnsköldsvik	40	1 000	31,2	2 733	2,7	4	11	273	
6	SE-Örnsköldsvik	130	750	30,3	2 654	2,0	7	14	348	
7	SE-Örnsköldsvik	100	700	31,3	2 742	1,9	6	12	288	
8	SE-Umeå	120	600	31,3	2 742	1,6	6,5	11	267	
9	SE-Luleå	80	1 500	31,3	2 742	4,1	5,5	23	566	
10	FI-Kemi	90	3 450	31,5	2 755	9,5	3,5	33	832	
11	FI-Kemi	200	1 000	33,2	2 908	2,9	5,5	16	400	
12	FI-Oulu	120	3 600	33,2	2 908	10,5	4,5	47	1178	
13	FI-Kemi	250	5 150	34,7	3 040	15,7	6	94	2348	
14	FI-Keski-Suomi	250	5 850	34,0	2 900	17,0	6	102	2545	
15	FI-Pyhäjoki	110	600	36,1	3 158	1,9	4	8	189	
16	FI-Kemi	450	2 900	37,4	3 276	9,5	9,5	90	2257	
17	FI-Sea 1	40	2 340	39,5	3 460	8,1	15	121	3036	
18	FI-Sea 2	25	2 230	44,9	3 930	8,8	12	105	2629	
19	FI-Sea 3	20	840	42,5	3 720	3,1	12	37	937	
20	SE-Sea 4	30	2 900	40,0	3 500	10,2	16	162	4060	
life-time 25 a			**38 810 MW**			**118**	**TWh**	**963**	**24 068**	**M€**
**120 m hub height*								**8,1**	**€/MWh**	

Table 8. Summary of wind power generation in the studied area, with interconnection costs per unit (€/MWh) and for the whole lifetime (Mrd.€)

	Power [MW]	**Energy** [TWh]	**Costs** [€/MWh]	**Costs** [Mrd.€]
FI Offshore	5 410	20	13.2	6.6
FI Onshore	22 550	66.9	5.8	9.7
SE Offshore	2 900	10.2	16	4.1
SE Onshore	7 950	21.3	6.9	3.7
Total	**38 810**	**118**	**8.1**	**24.1**

6 Hydrogen pipeline connection

Another alternative is to connect the wind farms to the consumption sites with hydrogen pipeline instead of electricity transmission lines. Electricity is more flexible in terms of its final use, as hydrogen production is merely one alternative among other possible electricity uses at the destination. The comparison method used in this work does not take into account this built-in flexibility or stiffness of the transport methods.

The transport cost for comparative purposes is calculated per energy content of hydrogen available at the destination, which includes the efficiency loss associated with hydrogen production. For simplicity, electricity and pipeline transport methods are assumed to have identical losses during transportation. Hydrogen production costs are also excluded for simplicity. The unit cost transport (C) is thus calculated for a unit of hydrogen according to Equation (1) for both electricity and hydrogen alternatives.

$$\mathrm{C}\left(\frac{€}{\mathrm{MWh_{H2}}}\right) = \frac{\text{Transmission costs (€)}}{\text{Electricity amount }(\mathrm{MWh_{el}}) \cdot \mathrm{H_2}\text{ conversion efficiency }(\mathrm{MWh_{H2}}/\mathrm{MWh_{el}})} \quad (1)$$

Transmission costs include the capital and operational expenses of the internal collector network within the wind park, long-distance cables or pipelines, and other necessary auxiliary equipment such as transformers or hydrogen compressors.

In this high-level study, no significant price difference was observed between the energy transportation methods, provided that the connected electric capacity is above 1500 MW. For capacities that are below 1500 MW, electricity transmission was preferable (Figure 14). Additionally, offshore applications appeared to be cheaper to implement with pipeline systems, but the results are also susceptible to more uncertainty. Consequently, more accurate data and analysis is necessary to highlight the differences between the transport methods. Furthermore, intelligent pipeline and interconnection design by lumping multiple production sites together should be considered in future studies.

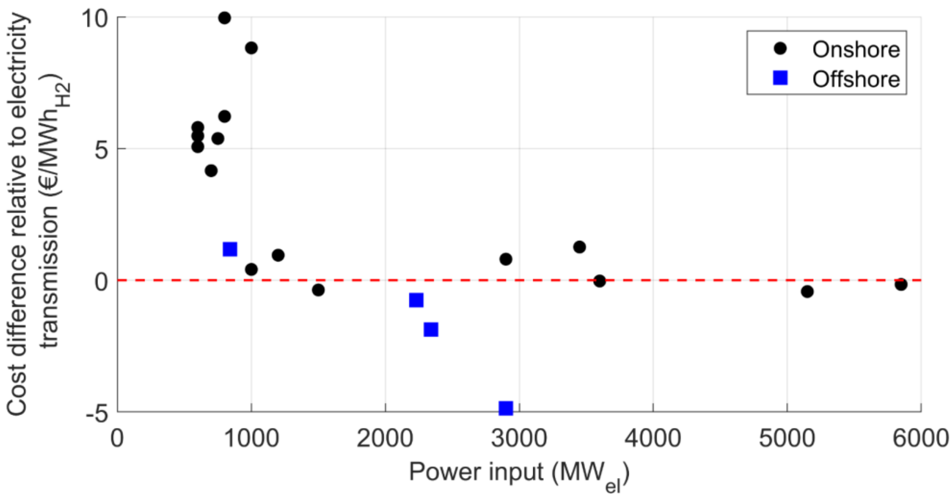

Figure 14. Relative cost difference of hydrogen transmission system when compared with electricity transmission. Positive values reflect to cases where electricity transmission is preferred, and negative values indicate favorable conditions for pipeline transport.

6.1 Coastal trunk pipeline

Another vision for the hydrogen pipeline is a trunk pipeline which follows the coastline of the Bothnian bay region (Figure 15). Transport capacities are in this case very large, which benefits the pipeline infrastructure. The cost of the pipeline is estimated to be 2 – 3 B€ (Table 9), and compressors could be expected to have an additional cost of at least 2 – 4 B€.

The compressor costs are hard to estimate more accurately without additional assumptions about the flow (e.g. how much hydrogen is injected and removed at different sections). The initial compression was assumed from 1 bar, but if the electrolysers can provide hydrogen at 30 bar, the compressor cost could decrease. On the other hand, this will be reflected as an increase in the costs and specific electricity consumption of the electrolyser.

There are numerous viable configurations for the pipeline system, which were not compared and analyzed further in this study. Pathing, flow direction, capacity, booster station locations, and the presence of existing infrastructure, and renewable potential all need to be decided for the final implementation. Finally, it is also likely that the system will be advancing in stages, with first sections being relatively short and used also for technology validation.

Total energy storage capacity of the pipeline is estimated to be 150 GWh$_{H2}$, based on assumed pressure range of 40 – 100 bar. Hydrogen pipelines can therefore be said to have a limited dual-purpose role, enabling the buffering of hydrogen – as well as transmission. Additional lined rock caverns could be placed in strategic application sites to further enhance the storage capacity.

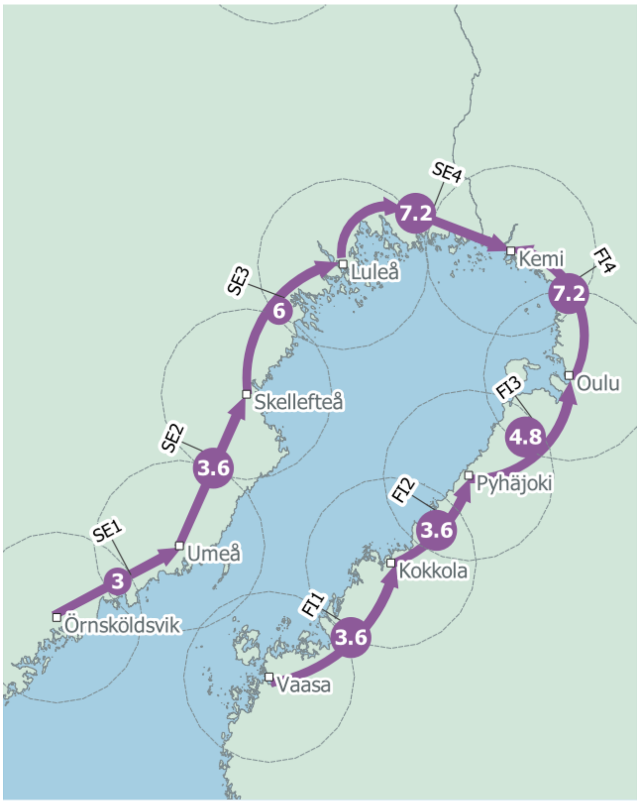

Figure 15. Vision of the coastal trunk H_2 pipeline for the Bothnian bay. Numbers refer to pipeline capacity in GW_{H2}.

Table 9. Distances and costs of pipeline segments, excluding compressor costs.

Location	ID	Distance (km)	Cost (B€)
Örnsköldsvik-Umeå	SE1	97	0.17
Umeå-Skellefteå	SE2	111	0.21
Skellefteå-Luleå	SE3	114	0.29
Luleå-Kemi	SE4	138	0.38
Vaasa-Kokkola	FI1	120	0.22
Kokkola-Pyhäjoki	FI2	78	0.15
Pyhäjoki-Oulu	FI3	99	0.23
Oulu-Kemi	FI4	110	0.31
Total		**867**	**1.96**

7 Investments and electricity balance

Two estimates are presented for the investment scale and the electricity balance of the system. Case 1 is based on a moderate implementation strategy, where the electricity demand of the steel industry is limited to the previously introduced low estimate of 25 TWh. Additionally, methanol synthesis is assumed to consume about 25 TWh of electricity. Furthermore, case 1 does not include a hydrogen pipeline nor any hydrogen storages. The additional wind power generation is assumed to be fixed to 100 TWh for both cases. Case 2 is a more ambitious scenario, where the high electricity demand for steel is realized (50 TWh), but also the methanol synthesis electricity demand is increased to 50 TWh. Additionally, the scenario includes a hydrogen pipeline, and a hydrogen storage. Electricity balance of the two cases is shown in Table 10.

Table 6. Electricity supply and demand

		Case 1	Case 2
Wind power generation	TWh	100	100
Steel decarbonization	TWh	25	50
Methanol (hydrogen generation)	TWh	25	50
Remaining electricity	TWh	50	0

The total investment need for the region can be expected to be in the range of 80 B€ for the first case, and 130 B€ for the second case, as is illustrated in Table 11. The largest single investment is estimated for the wind power generation capacity. CO_2 demand in case 2 would be about 7 Mt of CO_2, whereas the available potential was earlier identified to be about 14.8 Mt. Wind power capacity can therefore be identified as the bottleneck of the system, as the hydrogen generation for methanol synthesis is limited by the power supply.

Electrolysers also form a significant portion of the investment (15-32 B€). This is largely affected by the assumed unit cost (750 €/kW) and the capacity factor (28%, or about 2500 full load hours). The excess heat produced by the electrolysers at the envisioned scale is also significant enough to affect the heat availability of entire municipalities.

Table 11. Investment scale for the main system components

		Case 1	Case 2
Wind turbines	B€	50	50
Wind farm collector network and transmission network	B€	10	10
Electrolysers (steel and methanol synthesis)	B€	15	32
Carbon capture and utilization (Methanol synthesis)	B€	3	7
Hydrogen coastal trunk network (incl. compressors)	B€	0	10
Hydrogen storages	B€	0	20
Total	**B€**	**78**	**129**

8 Conclusions

The Bothnian Bay area has great potential to become a globally important producer and export hub for carbon neutral steel, fuels and chemicals. The area inherently features the important elements of transformation: industry for using renewable electricity and hydrogen, biobased-CO_2 for sustainable methanol production, and a rather close access to the planned renewable electricity capacity.

Availability of affordable electricity is a prerequisite for widespread decarbonization and sectoral renewal. The study reveals that the wind power potential in the area is enough to cover carbon free steel production even in the high-end estimation. In addition, a significant amount of biobased CO_2 emissions can be converted to e-fuels or chemicals with the remaining power capacity. However, massive and timely investments are required for the change across multiple sectors to meet the planned zero-emission targets (Finland by 2035, Sweden by 2045).

Wind power interconnection costs between wind farm sites and consumption areas were estimated to be lower in Finland than in Sweden, which may create an advantage for industries based on renewable electricity. The cost difference is attributed to difference in building costs (unit costs for transmission network). However, more comprehensive research is required to verify and elaborate the results achieved in this strategic level study. For instance, a supplementary study would be necessary to estimate the necessary improvements to current national grid infrastructure so that the necessary volumes of energy can be transported. Moreover, the development of electricity market area prices and export volumes were not considered in this study.

Future energy systems are likely to incorporate elements of both electricity transmission and chemical transportation (hydrogen). A clear cost difference between hydrogen pipeline transport and electricity transmission could not be established in this study without having a more refined connection plan, case-specific parameters, and more reliable cost data. Moreover, hydrogen transport is at a very different life cycle stage compared to electricity, which, at least from a risk management side, makes electricity a safer alternative to initially proceed with. Understanding of how various resources (electricity, heat, hydrogen, CO_2) can be linked and matched with the demand side at different locations and timeframes is a monumental challenge which requires further work.

Hydrogen production generates excess heat, which could be reflected in the placement of electrolysers to meet the local heat demand. However, the scale of local heat production from electrolysers could greatly exceed the demand, especially during the summer.

Power system decarbonization measures, such as the large-scale implementation of wind power, are likely to increase the demand for electricity and heat storages. Chemical energy storages (hydrogen, carbon-neutral methanol or methane) are feasible for monthly and seasonal time scales. Pipeline systems have a dual-purpose role for both transportation and storage, as well as the capability of connecting storages between different regions. Such dynamic aspects of energy supply and demand was not part of the study, and it should be analysed in future studies.

This study focused solely on the Bay of Bothnia but resources and needs exist in other areas as well. Future studies could be extended to include larger areas of the Nordic countries, which each have their own assets. For instance, there is significant offshore wind potential in Åland, Baltic Sea, and the Norwegian coast, as well as onshore wind potential in Eastern Finland and Southern Sweden. Biogenic CO_2 potential in Central and South-East Finland also offers huge opportunities for CO_2 utilization. Energy market of the central Europe also influences the conditions in Norway, Sweden and Finland, which is reflected by the import and export balance of each country.

We propose to continue the research on modelling Finland, Sweden and Norway on strategic level as an energy system based on renewable electricity, and then move into hourly modelling of the regions. Progressing to the more detailed levels should be conducted in cooperation with industrial partners, as the data is typically much better than what is available in the public domain.

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