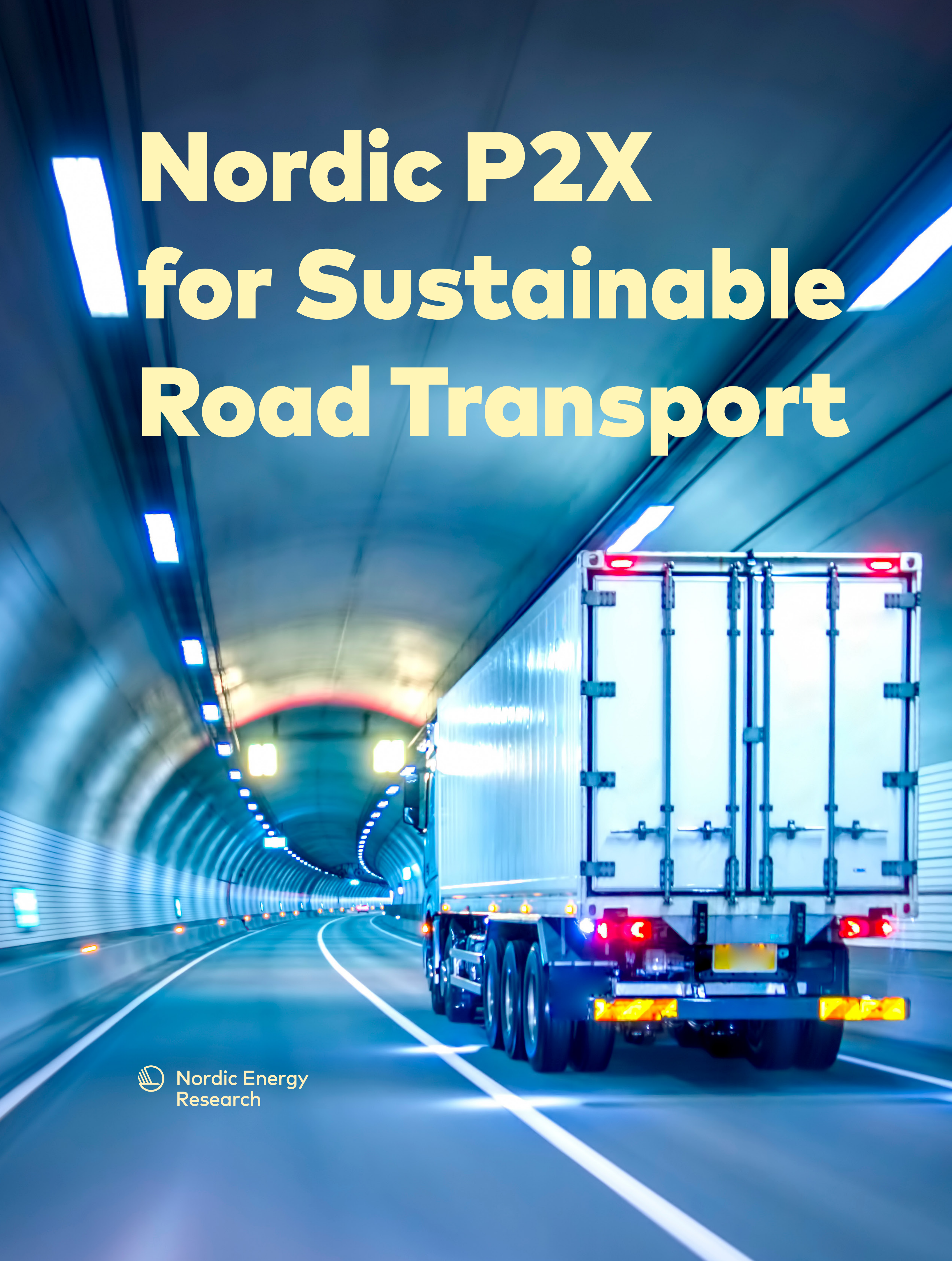
Nordic P2X for Sustainable Road Transport



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Nordic P2X

for Sustainable Road Transport

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Foreword

On 25 January 2019, the Nordic Prime Ministers of Finland, Iceland, Sweden, Norway and Denmark signed the "Declaration on Nordic Carbon Neutrality" in which they commit themselves to work towards a carbon-neutral Nordic region.

To assist this effort, the prime ministers commit themselves to intensify Nordic cooperation to "decarbonizing the transport sector, including through an inter-modal shift, efficiency, electrification, and use of sustainable renewable fuels".

Responding to the declaration, the Nordic energy ministers, at their meeting on 26 June 2019, agreed to strengthen their cooperation in order to meet the objectives set out in the prime ministerial declaration on Nordic Carbon neutrality. They expressed the opinion that Nordic energy cooperation can deliver a decisive contribution to the goals stated in the Declaration. Following that declaration, the incoming Danish Presidency of the Nordic Council of Ministers for 2020 initiated the establishment of this project named Nordic P2X for Sustainable Road Transport.

The aims of this project have been to identify key parameters for e-fuel production siting decisions and to assess the potential for reduction of greenhouse gas emissions from road transport within the Nordics by the use of electrofuels. Renewable electricity from wind and solar are growing fast in the Nordics. This gives an opportunity for decarbonising the road transport sector. This encompasses both heavy (trucks and buses) and light vehicles (cars, mopeds and motorcycles). Although the light vehicle fleet is being electrified using batteries, this transition will take time thus making electrofuels relevant to include in this context.

The specific project goals have been to identify candidate locations in the Nordic countries for hydrogen production and consecutive electrofuel production (gaseous as well as liquid) for fuelling road transport within the Nordics. In addition, the project has ranked the identified sites for hydrogen and other forms of electrofuel production considering: 1) availability of low-cost renewable electricity and network capacity at site, 2) sufficient water resources for hydrogen production at site, 3) access to required streams of e.g. carbon dioxide – biogenic, fossil, direct air capture – to be used in the production of electrofuels, and 4) use of by-products such as excess heat, oxygen etc. from the process. Finally, the project has proposed policy messages for the most promising electrofuels in a Nordic context.

Nordic Energy Research have managed the tender process and administered the process towards finalisation of the report. The work is a collaboration between CIT Industriell Energi AB in Sweden (lead), THEMA Consulting Group in Norway and VTT Technical Research Centre of Finland.

The project team was supported by a steering group, which contributed with context and quality assurance based on extensive expertise both on the national and Nordic levels. The steering group members were:

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Executive summary

Electrofuels (e-fuels) produced from renewable electricity in the Nordics could contribute to both increasing the domestic production of renewable fuels, and to achieving national targets for decarbonizing the transport sector. Reducing emissions from road transport can, to a significant degree, be achieved by vehicle electrification – being far more energy efficient on a well-to-wheel basis than e-fuels – but there is still a large demand of liquid and gaseous fuels expected, especially for heavy-duty transport, even in a time frame up to 2050. Together with biofuels, e-fuels – including both liquid and gaseous, carbon-containing fuels and hydrogen – could be an option to fill this demand.

The project – conducted in collaboration between CIT Industriell Energi AB, THEMA Consulting AS and VTT Technical Research Centre of Finland – identified candidate locations in the Nordic countries for hydrogen and subsequent e-fuel production (methane, methanol, DME and FT-diesel) for fuelling road transport within the Nordics for a timeframe up to 2045. Sites have been ranked by production costs, greenhouse gas emission savings, and infrastructural aspects. Water resource availability was also analysed, but results showed that water availability is not a critical factor for plant siting decision within the Nordics.

The major conclusions from the present project are:

For e-fuel production sites co-located with industrial emissions sources in the Nordics, the key features of attractive sites are a low power price, potential by-product revenues and plant size

The location of e-fuel production sites at industrial large-scale CO_2 sources in low power cost regions is a viable near-term choice to allow the rapid ramp-up of carbon-based e-fuel production in the Nordics. This is due to the most important factors for low e-fuel production costs being: a low power price, potential revenues of by-products (oxygen and heat), and plant size (economies of scale). For hydrogen e-fuel production, where plant economics are even more sensitive to power prices, this conclusion is also considered valid. Even though hydrogen production is not dependent on a CO_2 source, benefits from co-location with industrial infrastructure are still to be expected, and low power price regions will still be the most attractive from a production cost perspective.

The present assessment is based on the current energy system infrastructure and known near- to medium-term developments. We analysed whether locating hydrogen production where power was cheapest in the Nordics and then paying for hydrogen transport was likely to be cheaper than local hydrogen production for e-fuel production facilities located at industrial CO_2 sources. This analysis indicates that power price differences within the Nordics are too small relative to the costs of hydrogen transportation to motivate off-site hydrogen production elsewhere in the region. Future changes to the relevant infrastructure – such as the build-up of an extensive hydrogen transport infrastructure or a CO_2 transport system – might lead to differing conclusions.

Power consumption is the main limiting factor on the volume of fuels that can be produced

The upper limit for e-fuel production is set by the maximum size of electrolyser chosen in the analysis (200 MW_{el}). This assumption accounts for potential limitations in electric power supply infrastructure. The theoretical amount of e-fuels produced based on the availability of carbon dioxide would be substantially higher. Consequently, a massive ramp-up of capacity could generate substantial amounts of e-fuels provided there was an available supply of renewable power. The estimated e-fuel amounts generated from the 15 sites with the lowest production costs in the Nordics correspond to a share of about 10 % of total energy demand for road transport, well in line with e-fuel uptake scenarios developed as part of this study. However, the focus of the analysis was on identifying the relative attractiveness of different e-fuel production sites and further investigation would be necessary to come up with better founded estimates of possible e-fuel production volumes.

E-fuel production at smaller scale from biogas plants can be a cost-competitive alternative from a national perspective

Co-location with large biogas plants can be a cost-competitive solution from a national perspective, since the available pure CO_2 stream reduces investment and operating costs. However, the volumes of e-fuels that can be produced at lower cost at biogas plants are considerably smaller compared to levels reached at large-scale industrial CO_2 sources. Further, large biogas plants are mainly situated in southern Sweden and Denmark, with relatively high power prices, which makes large-scale e-fuel production in low power price zones (e.g. Norway) the economically preferable option from a Nordic perspective.

E-fuels produced in the Nordics can achieve – and surpass – the greenhouse gas reduction requirements of 70 % from the recast EU renewable energy directive

With respect to greenhouse gas emission reductions, e-fuels produced within the Nordic countries can surpass the 70 % reduction requirement of the recast European renewable energy directive, based on currently available calculation methodology. Thus, e-fuels could contribute to reaching mandatory levels of advanced renewable transport fuels. In this context, it is important to note that the final methodology for e-fuels specifically is not yet specified. E-fuel production sites are expected to use power sourced from a portfolio of onshore wind sites, complemented by grid power, which would give emission reductions above 90 %. Even e-fuel production in the Nordics using grid electricity is expected to be compliant with the reduction target of 70 %, excepting Denmark and Finland in the very near term (2025). In addition to access to renewable electricity, the major site-specific factor influencing the greenhouse gas emission reduction potential is heat export opportunities, which are expected to allow emissions to be allocated to the useful heat that is generated as a by-product in the production process.

Whether carbon dioxide is of fossil or biogenic origin does not impact the greenhouse gas emission reduction potential of e-fuels, which, based on currently available information, is reflected in the set-up of EU directives. From a long-term perspective, the use of fossil fuels will/should be phased out or converted to bioenergy where possible. Therefore, biogenic carbon dioxide sources, and/or applications with intrinsic CO_2 emissions such as from cement industry, may be a more secure source. A more comprehensive life cycle assessment, which accounts for site-specific conditions, the impacts of plant construction and allocation to other non-energy by-products, e.g. oxygen, should be considered. To understand the total climate impacts of increased e-fuel production in the Nordics a system level analysis would be needed.

Fuel distribution infrastructure is favourable for most sites that are top-ranked from a cost perspective and for all sites in Denmark and Southwestern Sweden

The three aspects most important for the ranking based on distribution infrastructure are the availability of a harbour at the production site, that the fuel produced can utilize existing distribution infrastructure, and proximity to demand centres. Most top-ranked sites with respect to production costs have access to a harbour, but not all. On the other hand, all sites in Denmark – though not top-ranked from an overall

Nordic cost perspective – have access to the natural gas grid and are located close to demand centres. It is clear that the possibility to utilize existing distribution infrastructure benefits the near-term development of e-fuel production. This is the case for liquid drop-in fuels and for e-methane where there is access to a natural gas or biogas grid.

E-fuels for road transport and P2X in general need to be analysed from a broader perspective

Building up a renewable e-fuel production infrastructure requires vast investments and large amounts of additional renewable electricity generation. A more holistic approach is necessary to clarify the roles of e-fuels – and P2X applications for materials, chemicals, or energy storage in a broader sense – for the future energy system, since all these uses (and direct electrification) will compete for the same renewable electricity. Competition between different sectors for the use e-fuels, from heavy road transport, marine transport to the aviation sector, also is an important factor to account for from a system perspective. The present study – which focuses on identifying optimum locations for e-fuel production in the Nordic countries – can be used as a starting point for or contribution to a broader analysis. With respect to low-carbon transport, the results of the present study can serve as benchmark for e-fuels with respect to other measures such as biofuels or direct electrification.

This project provides a foundation for a broader consideration of the appropriate use of e-fuels by establishing an analytical framework for the assessment of costs and a detailed database of large-scale industrial CO_2-point sources that could be used for e-fuel production in the Nordics

A database of e-fuel production cost and greenhouse gas emission reductions covering 232 industrial sites within the Nordics has been established. The database can form the basis of further investigations and allows for customization and adaption. Carbon dioxide amounts, origin (fossil/organic), and concentration estimates, as well as local markets/demand for by-products oxygen and heat are included in the database. Power price scenarios based on a sophisticated modelling approach for the timeframe 2025 – 2035 – 2045 for the Nordic electricity price zones are included. The analytical framework – which links a comprehensive Nordic power system model, structured techno-economic data, and life-cycle-based greenhouse gas emission performance analyses – is a valid starting point for further studies of the role of e-fuels in the Nordic energy system.

Contents

1 Introduction

The Nordic countries have ambitious targets for decarbonizing the transport sector. To reach these targets a wide range of measures are needed, including energy efficiency improvements, electrification, and biofuels. In this perspective, electrofuels (e-fuels) could potentially be an important part of the transitional pathway.

The main drivers for e-fuels are substantial greenhouse gas emission reductions and a potential for energy storage. The emission reductions are dependent on e-fuels being produced from renewable electricity. The potential of e-fuels as energy storage is mainly related to being able to store intermittent renewable power production from wind and solar by conversion into chemical fuels. An important hurdle is that the production is considerably less energy efficient than other options such as electrification or biofuels.

Reducing emissions from road transport can, to a significant degree, be achieved by vehicle electrification but there will still be a substantial demand of liquid and gaseous fuels, even in a time frame up to 2050. Where low-emission electricity is available, e-fuels – including both liquid and gaseous, carbon-containing fuels and hydrogen – could be a low-carbon option to fill this demand and to increase domestic fuel production.

1.1 Project scope

The present project focuses on identifying candidate locations in the Nordic countries for hydrogen and subsequent e-fuel production (gaseous as well as liquid) for fueling road transport within the Nordics. The time frame for the evaluation is up to 2045 with intermediate years 2025 and 2035. Ranking of potential sites according to different criteria (production cost, greenhouse gas reduction potential and infrastructure aspects) was done to identify specific sites in the Nordic countries that are suitable for e-fuel production. The siting analysis, in combination with specific case studies conducted, also is the basis for identifying more general aspects making a good production site for e-fuel production, giving both guidelines for national siting considerations, as well as for siting with respect to potentially changing energy system prerequisites in the medium to long term future.

The more specific focus of this project is to analyse the factors impacting *siting* of e-fuel production plants and to rank specific potential production sites, based on different ranking criteria. To provide input to the focus of this analysis and a context in which the results can be interpreted, e-fuel uptake scenarios are developed. The actual results of the ranking analysis are, however, not directly impacted by the choice of uptake scenarios.

The study is based on specific site information, engineering data on e-fuel production, dynamic modelling of the power system and established methodologies for calculations of e.g. greenhouse gas emissions. In addition, all aspects considered relevant are discussed and their potential impact estimated. However, given the time frame of the study and the complex system interactions several simplifying assumptions had to be made. The time perspective of the study is from 2025 until 2045. In this perspective, the dynamic development of the power system is considered, as well as aspects related to demand scenarios and technological developments. However, it has not been possible to fully take future developments of all related aspects into account. Especially, the treatment of the following aspects, that are considered partly out of scope for the present study, should be noted:

- The long-term development of the industrial sector towards a low-carbon or carbon-neutral economy are not part of the present analysis. This includes effects of increased electrification of industrial processes, parallel hydrogen developments such as the Hybrit project in Luleå, and the phasing out of fossil fuel use on e.g. availability on CO_2 sources for carbon-containing e-fuels.
- The policy framework within the EU and its future development will impact e-fuel development. The current framework is described and accounted for – in particular for the greenhouse gas emission evaluation – but a detailed evaluation of the impacts of directives in relation to carbon capture and storage/utilization (CCS/CCU) and vehicle-related directives, such as the Fuel Quality Directive, is not part of the present study.
- Infrastructural aspects such as the future existence of carbon dioxide or hydrogen transport infrastructure are not evaluated in detail. Hydrogen transport is evaluated on a case study basis comparing hydrogen and power transport cost in the framework of e-fuel production. Transport of carbon dioxide as part of CCS infrastructure has not been studied specifically.

- The study does not aim at providing specific production cost levels for e-fuels but rather highlights regions within the Nordic countries with favorable conditions for e-fuel production, as well as specific key enablers for cost-competitive production of e-fuels

The scope of the study as well as the delimitations are further elaborated on in the following sections, setting e-fuels and the siting of e-fuel production sites in a system context.

1.2 E-fuels in context

Fuels of various types can be produced based on the conversion of electricity into hydrogen, via electrolysis. Hydrogen and carbon dioxide, from various sources, can then be synthesized into a range of different gaseous or liquid fuels (see Figure 1.1). Fuels that can be produced via this production route are for example hydrogen, methane, methanol, DME (dimethylether), ammonia, as well as synthetic diesel, gasoline and jet fuel. There are various uses for this type of substances – methanol can, for instance, be blended at low shares into gasoline or be used as neat road transport fuel or as marine fuel in shipping, and is an important base chemical in the chemical industry. The term power-to-X (P2X) covers all generation of fuels or chemicals from electricity, via this route. The term e-fuels further indicates that the produced substances are produced for the fuel market, primarily in the transportation sector. The P2X (including e-fuel) production route denotes thus a whole category of production process routes, which have the first electrolysis step in common and where the second, synthesis, step varies depending on the type of substances that are the final products. In common for the P2X processes is also that the energy content of final product is derived from electricity and that the final product – be it H2, methanol or FT-diesel – is identical to the same product produced from biogenic or fossil resources.

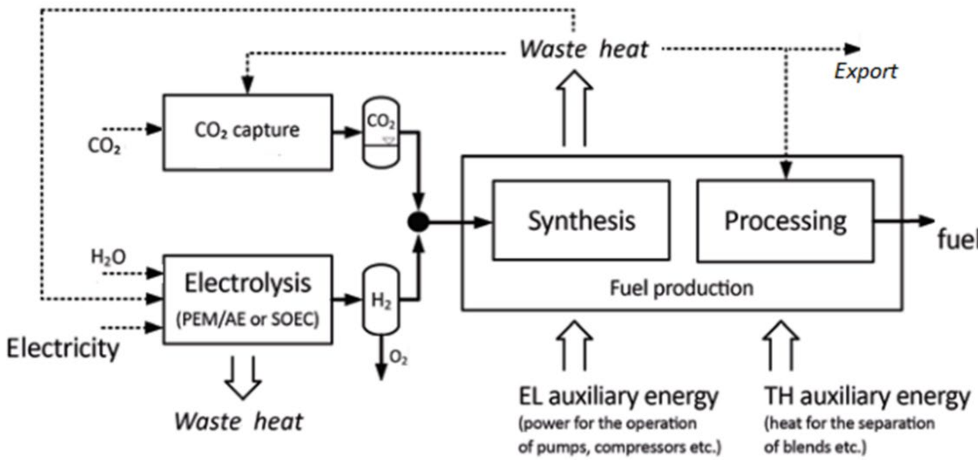

Figure 1.1 Principle flow chart for the e-fuel or P2X process, converting electricity and hydrogen into various types of fuels (based on [1]*)*

Even assuming that e-fuel use is primarily directed to the markets for renewable transportation fuels, the system interconnections for e-fuel production are numerous. Firstly, from a product market perspective most fuels produced can be used in different transportation segments and could substitute for both fossil fuels and biofuels. On a well-to-wheel basis, e-fuels are however outperformed by the direct use of electricity for electric driven transportation, which is far more energy efficient. The major drivers for e-fuels– in relation to fossil fuels – are to provide substantial greenhouse gas (GHG) emission reductions. In addition – in relation to biofuels –, limits to available sustainable biomass resources for biofuel production drive e-fuels deployment. E-fuels potentially provide an option to increase the availability of sustainable, low-GHG liquid and gaseous fuels, primarily for transportation segments which are difficult to electrify, such as heavy-duty transport, shipping, and aviation. In the shorter time frame, there will however be a demand for gaseous and liquid fuels also for other transportation segments since system transformation takes time.

Secondly, from a supply – or e-fuel production - perspective there are strong linkages to the power production and network systems, to various industrial (and non-industrial) CO_2 sources, and to the heating market and markets for other by-products (primarily oxygen). The linkage to the power production system also provides the remaining driver for the development of e-fuels, namely that the production of e-fuels can potentially act as energy storage for intermittent power production, from for instance wind and solar. The shares of renewable and intermittent electricity production have increased strongly over the last few years, and are expected to continue to increase, which also increases the need for power storage. In addition, these linkages impact the production cost of e-fuels, the potential GHG emission reductions, and infrastructural conditions. These aspects and linkages are in direct focus of this project and are thoroughly explored below.

Finally, the potential for e-fuels to provide substantial greenhouse gas (GHG) emission reductions is system dependent. Further, the possibility for countries and companies to be credited for such reductions, is also dependent on the regulatory framework for e-fuels. In the recast Directive on Renewable Energy (RED II) [2], e-fuels were introduced as one option to fulfil the targets for increasing shares of renewable fuels in the transportation sector and the GHG emission reduction targets. This has considerably impacted the recent interest for e-fuels in Europe (see further Sections 2.1, 2.2 and 5.7).

1.3 Drivers for the siting of e-fuel production

Demand projections for both hydrogen and carbon-containing e-fuels can be found in Chapter 3. An analysis of these projections suggests that hydrogen could potentially supply a large share of total e-fuel demand, but that there remains considerable uncertainty as to the level and composition of demand. Most likely, there will exist markets for multiple different e-fuels that supply different vehicle types. This project assesses the relative ranking of alternative production locations for e-fuels. Importantly however, these sites have been selected such that they have access to carbon dioxide, such that they can produce carbon-containing e-fuels using carbon captured onsite. Since this CO_2 source is not required for pure hydrogen production, the site list omits potential production sites suitable for pure hydrogen production. Nevertheless, the analysis of the sites ranked through the study does provide a benchmark for hydrogen production costs and highlights the relative importance of different factors in identifying the least-cost production locations.

Analysing the relative attractiveness of different e-fuel production sites in the Nordics inevitably requires us to make assumptions on future demand and cost conditions that are subject to significant uncertainty. From a policy perspective, it is important that we identify those locations that minimise socio-economic costs while meeting required demand. These socio-economic costs will include production, transport, infrastructure and emissions costs.

The best-performing locations will depend on developments in the e-fuels market and the future development of the European energy system. Key determining factors will include:

- The speed at which the power sector decarbonises. As generation is increasingly decarbonised, the emissions differences between alternative locations will diminish.[1]
- How quickly the hydrogen market and its associated infrastructure develops. In a well-developed hydrogen market, the importance of local power costs will decline and the proximity to hydrogen infrastructure will become more important.
- The extent to which carbon transport and storage infrastructure is developed. If carbon transport infrastructure is deployed rapidly, it may become more attractive to transport carbon to remote P2X production facilities instead of siting such facilities at existing emissions sources.

The best logistical setup for e-fuel production will depend on how the costs of transporting the inputs and final product stack up against variations in power costs, the extent to which the power consumed is renewable, the availability of CO_2 and opportunities to use surplus heat.

In this project, we have focused on potential production sites co-located with point sources for CO_2, reflecting the ubiquitous nature of power transmission infrastructure and the comparatively limited infrastructure available to transport CO_2 or hydrogen. Co-location at CO_2 sites is assumed to be the best near-term choice to allow for a rapid ramp-up of e-fuel production.

However, high electricity transmission costs or limited opportunities to utilise excess heat could suggest a role for the other alternatives in the longer term as demand for e-fuel is expected to increase. For a detailed discussion, see Chapter 4.1.

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[1] Section 4.3.2 provides further detail. However, it is important to note that our methodology assumes that power is supplied primarily from additional new renewable generation capacity.

1.4 Report structure

The present report is structured in the following way:

- Chapters 2 and 3 provides the background for the siting analysis, in terms of policy framework and e-fuel up-take scenarios for the Nordic road transport sector.
- Chapter 4 describes the type of e-fuel production sites that could potentially be relevant, to what extent they are and are not included in this study, and the overall methodological approach.
- Chapter 5 describes in more detail the analytical framework and input data for the main analytical steps for the siting analysis.
- In Chapter 6, the ranking results for all three ranking criteria, and all different parts of the analysis is presented.
- Finally, Chapter 7 includes the overall results and conclusions as well as some policy insights gained from the project.

2 Policy framework

There is a broad range of policy areas that might affect the development of e-fuels for the transport sector in the Nordic countries. Here, we limit the overview of the policy framework to the most recent and relevant developments within the EU, and to a very brief summary of climate policy ambitions for the transport sector in the Nordic countries.

2.1 Policy framework of the EU

There are two policy developments of the EU that are especially relevant to the development of e-fuels in Europe and in the Nordics, namely the recast Directive on Renewable Energy (RED II) [1], and the commission regulation on the monitoring and reporting of greenhouse gas emissions under EU ETS, which also guides the reporting of carbon capture and utilization (CCU) [2].

The RED II directive was adopted by the EU in December 2018, and encompasses the development of renewable energy as a whole. For the transport sector, it includes a target of 14 % renewable fuels by 2030, of which advanced biofuels should contribute with at least 3.5 %, and biofuels from raw materials that can be used for food or feed can contribute with a maximum of 7 %. In addition, renewable electricity used in transport as well as renewable liquid and gaseous fuels of non-biological origin can contribute to the target. Member states are also allowed to include recycled carbon-based fuels.

In RED II, the e-fuels studied in this report fall under term "renewable fuels of non-biological origin" meaning fuels whose energy content is derived from renewable sources other than biomass. The directive regulates that to be classified as renewable fuels, e-fuels need to be produced from renewable electricity. It also regulates that the GHG emission saving from the use of such fuels should be at least 70 % from 1 January 2021. However, the detailed methodology for calculation of GHG emission reductions for e-fuels is not yet specified in the directive. By 31 December 2021, the Commission shall adopt a delegated act to supplement RED II and to specify the methodology for assessing greenhouse gas emission savings for this type of fuels.

Already now, RED II includes detailed provisions on how to ensure that electricity used for e-fuels is renewable and that there is an element of additionality meaning that the fuel producer is adding to the deployment of renewable energy. These provisions, and how they can be interpreted, are highly relevant to the siting analysis and therefore further described in Section 5.6.

Carbon-containing e-fuels in general derive the carbon from various CO_2-sources. For all other CO_2 sources than ambient air, this is a form of carbon capture and utilization (CCU), where the end use is for energy purposes. A basic requirement for calculating the GHG emission reductions of the e-fuels, is that double-counting of carbon emission reduction from recycled carbon sources and e-fuel products needs to be avoided. This is regulated through the Commission EU ETS regulation on the monitoring and reporting of greenhouse gas emissions [2]. The regulation prescribes that carbon dioxide emissions captured and utilized for other purposes should be allocated to the original CO_2-emitting source. This means that the carbon emitted from the e-fuel in use can be assumed to be zero, similarly to biofuels.

2.2 GHG emission impact from e-fuels and EU regulation

The overall GHG emission impacts from e-fuels are dependent on the emissions due to capture of CO_2 and the production of e-fuels (e.g. emission intensity of electricity used for production of e-fuel) as well as the emission savings assumed due to replacement of fossil transportation fuels. The origin of CO_2 used for the e-fuel production does not have an impact on the tailpipe emission: In any case, the CO_2 used in e-fuel production is physically emitted when the e-fuel is combusted. This holds true for CO_2 from fossil and biogenic origin, as well as for CO_2 from direct air capture (DAC). Further, from a system perspective, the origin of CO_2– fossil or biogenic – does not impact the net effect on total greenhouse gas emissions from utilizing it for e-fuel production. The GHG emission reduction is instead achieved by a reduction of fossil gasoline or diesel use.

According to the current EU legislation, this is handled by counting the CO_2 emitted as emission already at the plant of origin of the CO_2, not in the e-fuel process. If the CO_2 is from fossil source, the CO_2 emissions are fully accounted for at the plant of origin. If the CO_2 is from biogenic sources, it can be counted with zero emissions (as carbon neutral) at the plant of origin, as the same amount of CO_2 as emitted is assumed to be sequestered during the growth of biomass feedstock. This assumption of carbon neutrality holds true, if the biomass is from sustainable origin and the renewal of the carbon stock in the biomass is guaranteed. If the e-fuel is produced from CO_2 by DAC, it can be assumed that the same amount of CO_2 is released from tailpipe as originally captured from atmosphere (similarly to biogenic CO_2). The specific emission impacts related to the DAC are due to emission of energy use for the DAC process.

Based on the existing EU regulation for the EU ETS (Emission Trading Scheme) and the RED II directive, one can conclude that the EU regulation will ensure that emission reductions cannot be double-counted. CO_2 emissions included in the ETS and captured for utilization shall be counted as emissions of the installation where the emissions originate and cannot be transferred to entities not covered by the ETS-directive. This regulation ensures that the GHG reduction of e-fuels is achieved by reduction of fossil fuels in the transport sector. If the carbon emissions were allocated to the transportation fuels instead of the plant of origin, production of e-fuels would be a way to reduce industrial emissions instead of transport sector emissions. What is crucial, however, is that the emission reductions are counted only once.

Since different CO_2 sources and markets are involved when utilizing CO_2 for e-fuel production, one can, however, expect complex market effects, linked to the value of CO_2. The cost of emission reduction, the carbon price and policy measures applied, differ considerably between different energy markets (power system, industry and transport). In addition, the market may value biogenic and fossil CO_2 origin differently, regardless of the similar tailpipe emissions in the end-use. Furthermore, the conditions for using CO_2 as a resource in the longer term may change since the use of fossil energy should be phased out in all sectors. These types of market effects are, however, outside the scope of this study, even though they may be relevant in the future. To understand the total climate impacts of CCU systems and e-fuels, in further studies the GHG emission impacts should be studied at system level, including the overall impacts from biogenic or fossil raw material use at the plant of origin of CO_2, as well as the systemic impacts due to increased electricity use for e-fuel production.

2.3 Policy framework in the Nordic countries

The Nordic countries each have ambitious climate goals and targets for de-carbonizing the transport sector and committed in early 2019 also to working towards carbon neutrality at the Nordic level through the common Declaration on Nordic Carbon Neutrality[2]. This declaration is a commitment to intensify cooperation within a number of areas, including decarbonizing of the transport sector (through an inter-modal shift, efficiency, electrification, and the use of sustainable renewable fuels) and contributing to further development and deployment of CCU.

The policy framework on the national level includes quantitative targets and more specific policy measures.

Norway's climate target for sectors outside the EU ETS (European Union Emission Trading Scheme), such as domestic transport, is a reduction of greenhouse gas emissions by 40% in 2030 compared to 2005 levels. Currently, domestic transport contributes to about 31% of Norway's total greenhouse gas emissions. Norway's Climate Law establishes Norway's overarching climate goal, which is to reduce the total greenhouse gas emissions by 80-95% in 2050 compared to 1990 levels.

In Sweden, the emissions from sectors outside the EU ETS should be reduced by least 63 % in 2030, compared to 1990, and by at least 75 % by 2040.[3] In addition there is a specific target for emissions from domestic transport – except from domestic aviation – which shall be reduced by at least 70 % until the year 2030, compared with

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[2] Declaration on Nordic Carbon Neutrality, Helsinki, 25 January 2019 (https://valtioneuvosto.fi/documents/10616/1457318/Declaration+on+Nordic+climate+neurtality.pdf - accessed 2020-06-19)

[3] A smaller share of this reduction (8 and 2 percentage units, respectively) can be achieved by so called complementary measures, such as investments outside Sweden.

2010. Until 2045, the target is that net emissions of GHG should be zero for Sweden in total. Currently, domestic transportation contributes with about a third of the total Swedish GHG emissions. Of this third, road transport is responsible for more than 90 %.

Finland's emission reduction target for the effort sharing sectors (sectors outside the EU ETS) is to reduce emissions by 39 % in 2030 compared to 2005 levels. Transport sector represent approximately 40 % of Finland's emissions in the effort sharing sectors, which highlights the role of transport sector in achieving the national target. Finland aims to decrease transport sector emissions by 50 % in 2030 compared to 2005 levels. In addition, Finland has set up a working group to prepare a roadmap for fossil-free transport, with a task to describe the means for achieving the 50 % reduction by 2030 and transition to zero-emission transport by 2045 [3]. Around 90 % of Finland's domestic transport emissions originate from road transport [4]

Denmark adopted in broad parliamentary agreement a new binding climate law in December 2019, committing to reach 70 % below its 1990 emissions by 2030 and climate neutrality by 2050.[4] There are no specific targets for the transport sector, except the EU targets and a general target to be independent of fossil fuels by 2050. Currently (2017), the Danish transport sector accounts for roughly 27 % of total Danish GHG emissions [5]. In relation to P2X, Denmark has recently also announced an agreement to construct additionally 6 GW of offshore wind energy (5 GW of those based on so called Energy Islands) and to invest in the development of P2X technology for providing transportation fuels.[5]

In Iceland, the government aim is to make Iceland carbon neutral by 2040. The Climate Strategy from September 2018 puts special emphasis on phasing out fossil fuels in transport, by e.g. support for electrification and biofuel production and banning new registration of fossil fuel cars by 2030.[6] GHG emissions from road transport in Iceland account to about 20 % of total emissions [6]. The first commercial P2X production plant is also situated in Iceland, where Carbon Recycling

[4] https://kefm.dk/aktuelt/nyheder/2019/dec/klimalov/

[5] https://via.ritzau.dk/pressemeddelelse/denmark-ushers-in-new-era-in-renewable-energy-vowing-to-create-worlds-first-energy-islands?publisherId=9426318&releaseId=13595799

[6] https://www.government.is/news/article/2018/09/10/Iceland-launches-new-Climate-Strategy-boosting-efforts-to-reach-Paris-goals/

International produces methanol in the George Olah Renewable Methanol plant since 2011.[7]

3 E-fuel uptake scenarios

The production of e-fuels is dependent on the potential market and uptake of fuels in the development towards a decarbonization of the transport sector. Therefore, the identification of relevant and well-motivated e-fuel uptake scenarios are included as one important task of the project. In this chapter, the purpose and relevance of these scenarios and the approach used is described together with the actual scenarios used.

3.1 Purpose and relevance of uptake scenarios

The uptake scenarios are developed to

- Provide a background for policy insights of the project results.
- Provide guidance on relevant production volumes and scale.
- Provide guidance on which e-fuels to focus on in the site ranking analysis.

The uptake scenarios developed aim to describe the development of the road transport sector in the Nordics, including Denmark, Norway, Finland, Sweden and Iceland. The scenarios consist of the development of the road transport sector at three different levels, which are all inter-related. At all levels, the development is of course dependent on the targets for decarbonization of the transport sector and the measures taken to reach these targets. However, in other respects the driving forces and the relation to the e-fuel potential differ:

- Firstly, the scenarios describe the development of total energy use for road transport in the Nordics. This is driven by the demand for road transport services and by the level of energy efficiency improvements within the system.
- Secondly, the scenarios describe the development of the demand for low-carbon fuels, as part of total energy use within the sector. This development is

[7] https://www.carbonrecycling.is/projects#project-goplant

linked to the level of electrification of road transport, but also to the GHG emission levels of the low carbon fuels and thus remaining fossil fuel shares.
- Finally, the scenarios should describe the development of the types of fuels used for road transport. This is from a demand perspective primarily driven by the vehicle market. The market development can for instance be divided into demand for vehicles that require drop-in diesel and/or gasoline type fuels, utilize dedicated low-carbon fuels (such as methanol or ethanol) and hydrogen-driven vehicles.

The linkage between these demand-oriented scenario levels and the share of e-fuels, contributing to these demands, is weak. Simply speaking, the fuel market does not really make a difference between e.g. bio- and e-methanol or bio- and e-diesel, since the fuel properties are otherwise almost identical. The GHG emission levels of e-fuels compared to their bio-based counterpart may have some impact, but for so-called advanced biofuels the difference compared to e-fuels is in most cases limited.

The factors impacting the share of low-carbon renewable fuels that could potentially be supplied by e-fuels are instead primarily linked to the supply side, the relative cost of fuel production and the availability of resources, such as sustainable biomass and renewable electricity production. These are also the factors that available studies of e-fuel potentials generally are based on.

Consequently, the uptake scenarios in this project are not scenarios for the e-fuel potential per se, but scenarios that can be used to explore the role of e-fuels in the road transport sectors.

3.2 Scenario development approach

Based on the principles described above the following scenario pathways have been developed within the project:

1. An overall development pathway for road transport demand in the separate Nordic countries and combined for the years 2025, 2035 and 2045, divided between demand for electricity and low-carbon fuels (including biofuels, hydrogen and other e-fuels) and remaining fossil fuel demand. This development is based on literature and the most consistent source found, the NETP study from 2016 (see below) [7]. For this background development we

use *one* pathway based on the assumption that the Nordic road transport system fulfils its ambitious GHG emission reduction targets.

2. Three alternative e-fuel scenarios (BASE, LOW and HIGH) describing different penetration levels for e-fuels as a share of total road transport demands. To mirror the uncertainty of the role of e-fuels in road transport, these scenarios are used to illustrate a plausible range and their resulting impact on energy flows. Alternative penetration levels used are based on an aggregate of various e-fuel potential studies, the main ones being Soler (2020, Concawe), Pursiheimo et al (2017), and Ikäheimo et al (2019) [8]–[10].
3. Finally, a fuel market development, describing potential demand for different low-carbon fuels – regardless of production route – is included. This development is based on an aggregate of transport demand scenarios for different Nordic countries and some input from heavy vehicle manufacturers. The results from this part of the uptake scenarios are used partly as input to the calculations for the BASE, LOW and HIGH scenarios above and partly they provide input to which e-fuels to focus on in the site ranking analysis.

The key sources used, and the assumptions based on these are briefly described below.

Nordic Energy Technology Perspectives (NETP2016) study provides an outlook on how to go beyond the 2°C target, towards a carbon neutral energy system in the five Nordic countries. The Carbon Neutral Scenario (CNS) in the study can be viewed as a test of the Paris Climate Agreement: Nordic CO_2 emissions drop by 85% by 2050 (compared with 1990 levels). In CNS transport accounts for the largest share of emissions reduction. Transport requires a dramatic emissions cut by 2050 and the target can be achieved through a three-pronged strategy of reducing transport activity (avoid), shifting to more efficient or less carbon-intensive transport modes (shift), and adoption of more efficient or less carbon-intensive transport technologies and fuels (improve) (see Figure 3.1). Improvements to technologies and fuels play the largest role in transport in the CNS, largely because Nordic countries have already introduced many policies based on 'avoid' and 'shift' strategies. The CNS requires an almost complete phase-out of fossil-fuelled cars and a rapid roll-out of EVs, especially in urban areas. Biofuel imports are needed to decarbonise long-distance transport modes. The data from NETP2016 are used to consistently describe the overall development pathway of road transport demand for all Nordic countries.

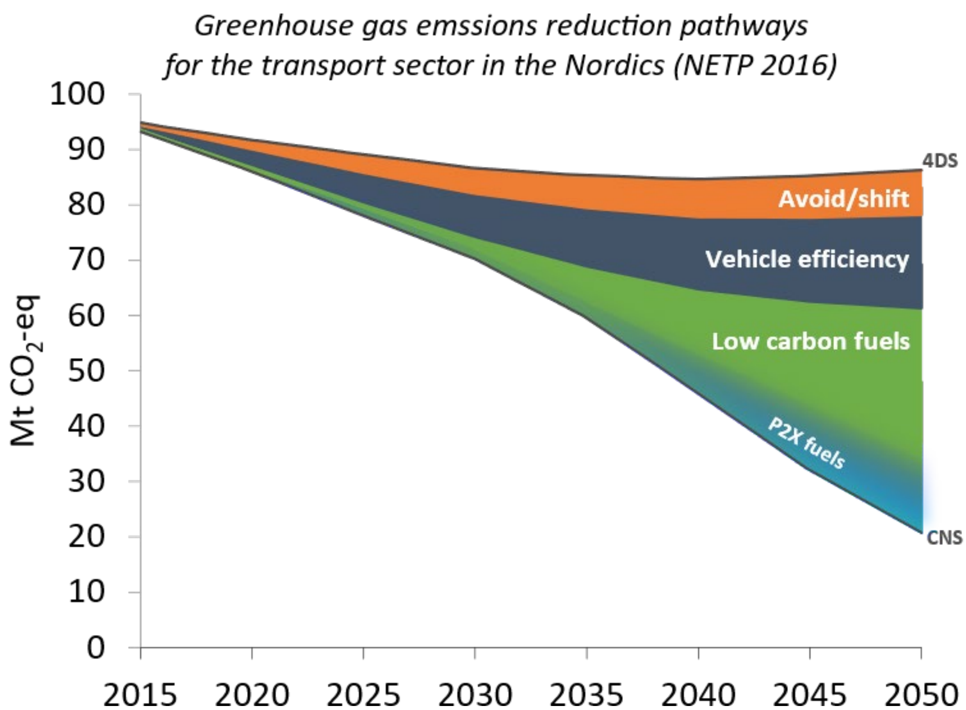

Figure 3.1: Reduction of greenhouse gas emissions from transport sector according to NETP 2016 scenarios illustrating different options for reduction [7]*. An illustration of the potential contribution of e-fuels is added (P2X fuels).*

To check for consistency with national scenarios for road transport demand, the CNS scenario of NETP2016 has been compared to other national studies, including energy scenarios from the Danish Energy Agency [11], a Finnish scenario study for the Finnish energy system [12], a study of the development of the vehicle park in Norway by the Transport economic institute [13], and scenarios from Trafikverket in Sweden [14]. The overall development trends in similar scenarios, striving for carbon neutrality by 2045 or 2050 are found to be similar to the development in NETP2016. However, the increasing shares of electricity use and the decline of fossil fuel use for road transport are in general even more prominent. In the more recent studies, by 2045 electricity shares may be expected to be up to twice of those in NETP2016 (reaching levels of roughly a third of total road transport demand) and fossil fuels use virtually zero. Specific e-fuel shares are in most cases not specified. This development is taken into account when estimating realistic shares for e-fuel penetration.

Recently, Concawe published a detailed literature review and analysis of the role of e-fuels in the European transport system. This study includes a review also of future demand scenarios until 2030/2050. According to this review the potential contribution of e-fuels by 2030 is below 15 % of predicted total EU transport demand by 2030 and below 30 % by 2050, according to most studies. When linking this demand to a realistic ramp-up of available carbon-free electricity in Europe, the report also concludes that literature shows that a production between zero and 50-80 Mtoe/a in 2050 (translating to 0-30% of total transport demand in the same year) would be realistic.[10] This conclusion has been guiding the assumed shares of e-fuel penetration. In this context, it should also be noted that expected fuel shares are lower for road transport than for other transport sectors (aviation and maritime).

Finally, the ERTRAC is currently developing a European roadmap for sustainable energies and powertrains for road transport for reaching well-to-wheel carbon neutrality by 2050, which should be finalized by the end of 2020. In this work different scenarios for fleet mix and for the mix of chemical energy carriers are being developed. Some of these combinations explore chemical energy carriers to be provided by high shares of e-fuels (from 10 up to 100 %). However, since the preliminary scenarios also include fairly extensive electrification, the shares of total road transport demand would translate to substantially lower levels.[8] .

The development of the Nordic power system in this study is analysed by the TheMA power market model (see Section 5.6), which uses three different scenarios for the power market development. The data obtained from the model is used to verify the consistency between e-fuel uptake scenarios and power market development within the present project. In these scenarios power production to cover a demand of power-to-gas is included. In the scenario Emissions Eliminated – which assumes carbon neutrality by 2050 beyond the power sector – electricity demand for total power-to-gas (in practicality, hydrogen) production corresponds to 60 TWh in 2045 for the Nordic countries in total. In the scenario Best Guess – in which EU 2030 targets are fulfilled and the power sector is decarbonized by 2050 – the same figure is about 26 TWh. In this model, the division between different sectors' usage of produced hydrogen, or the share being converted into other products, is not defined.

The national transport demand scenario studies mentioned above include in most cases also developments of specific fuel demands in relation to different transportation segments and types of fuels. Apart from a strong increase in demand for electricity driven vehicles, the various scenarios based on demand side analysis have in common that diesel and gasoline types of fuels are expected to retain the major market shares. The production routes for these fuels are, however, expected to transform from fossil fuels to biofuels, and in some cases e-fuels. In addition, the

[8] Personal communication with Roalnd Dauphin and Marta Yugo, Concawe.

demand for methane is also expected to remain relevant to road transport, but at a lower level. The demand for new fuels, such as methanol or DME is non-existent or very small in these studies. There are some differences between the Nordic countries, the main ones being that the demand for methane is expected to be larger in Denmark and that Finland and Sweden expect larger shares of biofuels. In addition, Denmark and Norway include scenario variants with a strong transformation into a hydrogen driven transport system.

Information received from heavy vehicle manufacturers seem to confirm the findings from the road transport demand scenarios. The main fuels in focus for Scania are for instance synthetic diesel fuels, methane and hydrogen. They view DME, OME (polyoxymethylene ethers) and ammonia as highly unlikely fuels for heavy vehicle road transport. Methanol is considered more interesting, but still not expected to reach any substantial market shares[9]. Recently, Volvo and Daimler launched a joint venture for large-scale production of fuel cell systems for mainly heavy-duty vehicle applications, which prove their interest in hydrogen as a future fuel.[10] The use of hydrogen – or possibly ammonia – as road transportation fuels will also be impacted by future developments on vehicle emission regulations on a European level. In case tailpipe carbon dioxide emission reductions are in focus, non-carbon containing fuels will reach higher shares. Nonetheless can the total share of e-fuels – and the associated necessary production sites/volumes and power demands – be expected to be in the same range.

The Concawe study also includes a market review of different types of e-fuels, primarily based on the total cost of different options. This review shows that the production cost is higher for drop-in liquid fuels, such as FT-diesel, than for methanol, DME and methane. However, when including vehicle and infrastructure related costs, i.e. comparing the whole system cost, total investment costs of alternative routes tend to be at the same order of magnitude. The studies reviewed, generally include methanol, diesel and gasoline, hydrogen, DME and OME for the road transport sector [10]

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[9] Personal communication, Magnus Fröberg, Scania, 2020-03-31
[10] https://www.volvogroup.com/en-en/news/2020/apr/news-3640568.html

3.3 Resulting uptake scenarios

The development pathway used for the road transport fuel demand is, as described above, entirely based on the NETP2016 and its Carbon Neutral Scenario. The pathway describes a decreasing demand for road transport energy use and decreasing share of road transport in relation to total transportation demand. Transport's total energy use in the CNS decreases by over 20% compared to 2000, despite a 70% increase in overall passenger and freight activity. By 2050, fossil fuels account for only 25% of transport final energy demand with EVs having a share of 60% for the passenger vehicle stock. Battery electric vehicles (BEVs) and hybrids account for the majority of EVs, with more limited prospects for hydrogen fuel-cell electric vehicles (FCEVs). The CNS sees biofuels underpinning long-distance, heavy-duty road and marine freight, as well as aviation. In CNS biofuels comprise nearly two-thirds of total final energy use in transport in 2050. Hydrogen deployment for transport vehicles, which may compete with biofuels, is coupled with higher investment risks and higher investment costs for both vehicle manufacturing and the deployment of a fuel distribution infrastructure.

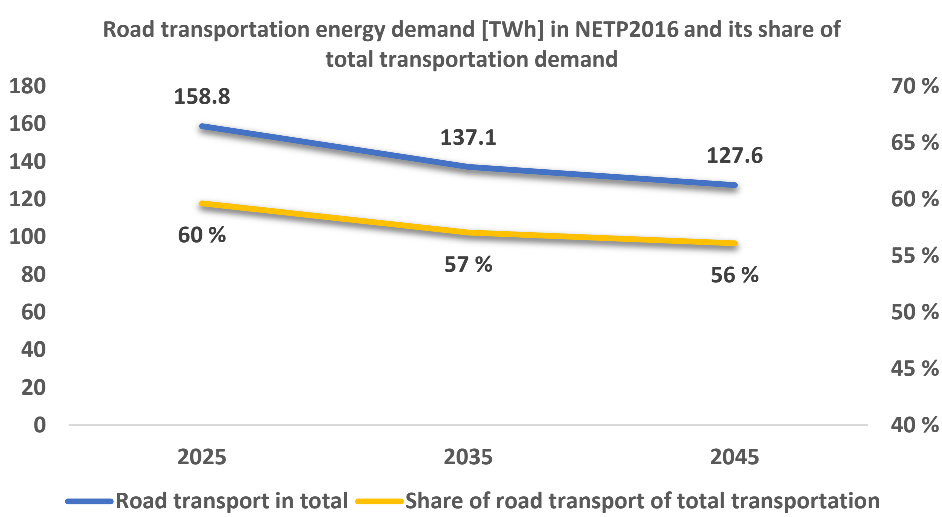

Figure 3.2 Development of road transport energy use in the Nordic countries, and its share of total transport demand (including all fuel types and electricity). Total transportation includes road, rail, air and water transports.

The three e-fuel scenarios developed are described shortly as following:

LOW – describes a lower e-fuel penetration level, which gradually increases up to 5 % of total Nordic road transport demand in 2045. It is based on higher demand for renewable electricity by other sectors than road transport.

BASE – describes a development where the penetration of e-fuels is between LOW and HIGH and gradually increases up to 10 % of total road transport demand in 2045.

HIGH – describes a higher penetration level, which gradually increases up to 20 % of total road transport demand in 2045. It is consistent with the estimated levels of realistic shares of e-fuels by Concawe study and describes a development in which a high share of total e-fuels production is used for road transport.

Note, that in these scenarios, all e-fuel shares are described as shares of *total* road transport demand, and that the shares of fuel demand would be higher.

In addition, a separate **H_2 variant** was calculated as a sensitivity analysis to all above scenarios describing situation where all e-fuels were produced as hydrogen only. This variant describes an extreme development towards hydrogen and is included for comparison, since hydrogen shares are quite low in the other scenarios.

The shares in all respective scenarios are linked to the overall Nordic demand, even though the development may vary strongly between countries. The review of the potential fuel market development has resulted in the following conclusions:

- The demand for renewable drop-in diesel for the heavy-duty transport sub-sector is expected to remain high throughout the studied time period. FT-fuels are therefore included as representing the largest shares of e-fuels in the uptake scenarios.
- Methane is expected to remain a niche fuel for some road transport segments.
- Methanol is not expected to take any substantial market shares for road transport. Nevertheless, production of methanol (and possibly DME), based on e-fuel production routes is relatively efficient and therefore it is still relevant to include in the siting analysis. Further, e-methanol may be produced for other markets, and smaller shares for methanol blend-in or niche markets also within road transport may arise.
- Hydrogen as a fuel for road transport seem to be an option that is either assumed to be negligent or to gain large market shares. Its development is dependent on dedicated efforts for developing a hydrogen society and therefore of a more binary character, but of large interest for the market.
- Other e-fuels, that have been discussed within the project, such as ammonia and OME, have been found to be of less relevance and have therefore been omitted from the study.

Since e-fuels are expected to account for only a share of total demand for each fuel type, exact scenarios for development of total demand for each fuel type are not directly relevant to the purposes of this study. However, based on the conclusions above, the following shares have been assumed for the uptake scenarios described above, see Table 3.1.

Table 3.1 Assumed shares of e-fuel as part of total road transport energy demand (including all fuel types and electricity use).

	LOW scenario			BASE scenario			HIGH scenario		
	2025	**2035**	**2045**	**2025**	**2035**	**2045**	**2025**	**2035**	**2045**
Total share of e-fuels	0.0 %	1.0 %	5.0 %	0.2 %	3.0 %	10.0 %	0.5 %	5.0 %	20.0 %
Share of e-methanol	0.00 %	0.05 %	0.50 %	0.00 %	0.20 %	1.00 %	0.04 %	0.50 %	2.00 %
Share of e-DME	0.00 %	0.05 %	0.50 %	0.00 %	0.20 %	1.00 %	0.04 %	0.50 %	2.00 %
Share of e-methane	0.00 %	0.12 %	0.80 %	0.05 %	0.57 %	1.80 %	0.12 %	0.97 %	3.80 %
Share of FT-liquids	0.00 %	0.73 %	2.59 %	0.15 %	1.98 %	5.59 %	0.30 %	2.98 %	11.59 %
Share of H2	*0.00 %*	*0.05 %*	*0.61 %*	*0.00 %*	*0.05 %*	*0.61 %*	*0.00 %*	*0.05 %*	*0.61 %*

Resulting inputs and outputs in the e-fuel production for total Nordic road transport demand are summarized in Table 3.2. Total e-fuel production for road transportation use and needed electricity for that production is also presented in Figure 3.3. As it can be seen, the total electricity demand in 2045 corresponds to up to three quarters of total electricity for power-to-gas in the THEMA Emissions Eliminated scenario, in the HIGH scenario. In the LOW scenario electricity demand corresponds to about 20 % of total power-to gas demand in Emissions Eliminated scenario and about 40 % of the Best Guess scenario. Thus, these up-take scenarios are estimated to be consistent with the electricity prices used for the siting analysis.

Table 3.2 Inputs and outputs in the e-fuel production for total Nordic road transport demand in the uptake scenarios.

	LOW scenario			BASE scenario			HIGH scenario			
	2025	**2035**	**2045**	**2025**	**2035**	**2045**	**2025**	**2035**	**2045**	
E-fuel share of road fuels	0.0 %	1.0 %	5.0 %	0.2 %	3.0 %	10.0 %	0.5 %	5.0 %	20.0 %	*Unit*
Total e-fuel production	*0.00*	*1.37*	*6.38*	*0.32*	*4.11*	*12.76*	*0.79*	*6.86*	*25.51*	*TWh*
Electricity input	*0.00*	*2.61*	*10.98*	*0.66*	*7.85*	*22.32*	*1.63*	*13.03*	*44.99*	TWh
Electricity input (8760 h/a)	*0.00*	*0.30*	*1.25*	*0.08*	*0.90*	*2.55*	*0.19*	*1.49*	*5.14*	*GW*
Electricity input (2920 h/a)	*0.00*	*0.89*	*3.76*	*0.23*	*2.69*	*7.64*	*0.56*	*4.46*	*15.41*	*GW*
CO2 input	*0.00*	*0.39*	*1.86*	*0.08*	*1.11*	*3.56*	*0.21*	*1.85*	*6.97*	*Mt/a*
Water input	*0.00*	*0.20*	*1.09*	*0.04*	*0.61*	*2.07*	*0.12*	*1.07*	*4.04*	*Mt/a*
Heat output	*0.00*	*0.89*	*3.09*	*0.26*	*2.68*	*6.41*	*0.63*	*4.42*	*13.05*	*TWh*
Oxygen output	*0.00*	*0.44*	*1.98*	*0.10*	*1.32*	*4.02*	*0.25*	*2.19*	*8.10*	*Mt/a*

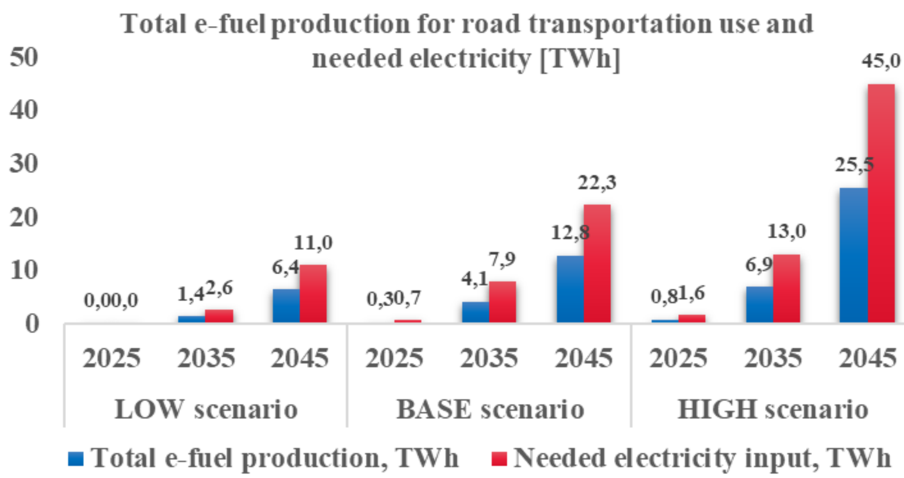

Figure 3.3 Total e-fuel production for use in the road transportation sector and the demand for electricity for the corresponding e-fuel production for the scenarios LOW, BASE and HIGH.

The results from the **H_2 variant** calculated as a sensitivity analysis to all above scenarios describing situation where all e-fuels were produced as hydrogen are presented in Table 3.3. For comparison e.g. in HIGH scenario for 2045 the needed electricity input is about 11 TWh lower in the H_2 variant (34 TWh) than in the base approach (45 TWh, Table 3.2).

Table 3.3 Inputs and outputs in the e-fuel production for total Nordic road transport demand in the uptake scenarios with H_2 variant approach.

	LOW scenario			BASE scenario			HIGH scenario			
	2025	2035	2045	2025	2035	2045	2025	2035	2045	
E-fuel share of road fuels	0.0 %	1.0 %	5.0 %	0.2 %	3.0 %	10.0 %	0.5 %	5.0 %	20.0 %	Unit
Total e-fuel production	0.00	1.37	6.38	0.32	4.11	12.76	0.79	6.86	25.51	TWh
Electricity input	0.00	1.96	8.50	0.49	5.88	17.01	1.22	9.80	34.02	TWh
Electricity input (8760 h/a)	0.00	0.22	0.97	0.06	0.67	1.94	0.14	1.12	3.88	GW
Electricity input (2920 h/a)	0.00	0.67	2.91	0.17	2.01	5.82	0.42	3.35	11.65	GW
Water input	0.00	0.37	1.72	0.09	1.11	3.44	0.21	1.85	6.89	Mt/a
Heat output	0.00	0.48	1.61	0.15	1.43	3.23	0.36	2.39	6.46	TWh
Oxygen output	0.00	0.33	1.53	0.08	0.99	3.06	0.19	1.65	6.12	Mt/a

4 E-fuel production siting and ranking methodology

In order to conduct a ranking analysis of different e-fuel production sites, it is necessary to understand the existing options for plant siting and the associated factors determining the economic and environmental performance of e-fuels at these sites. Based on that framework, it is possible to set up a methodology for ranking sites according to different criteria. The present chapter sets the scene for the ranking analysis.

4.1 Different e-fuel production setups

The analysis conducted in this report is based primarily on consideration of the current energy system, in which power generation remains emissions-intensive in many areas and large-scale physical hydrogen and carbon markets, as well as any transportation infrastructure underpinning them, have yet to be developed.

The efficient setup of e-fuel production depends on a wide range of different factors, the main ones being:

- The availability of renewable electricity and the electricity price,
- Whether a CO_2 source is needed (i.e. whether or not the relevant fuel contains carbon),
- The scale and quality of the CO_2 source,
- The availability of water for hydrogen production,
- The availability of markets for potential by-products (primarily heat and oxygen), and
- The proximity to product markets (especially for gaseous fuels).

From these basic observations, potential e-fuel production sites in this study have been divided into three main categories. The main categories are:

- Production of carbon-containing fuels based on carbon captured from point sources
- Production of carbon-containing fuels based on direct air capture
- Production of non-carbon e-fuels, i.e. hydrogen

4.1.1 Production of carbon-containing e-fuels based on carbon captured from point sources

Since the production of carbon-containing e-fuels involves two distinct processes – the production of hydrogen and then its subsequent transformation into the final product – there are three alternative logistical setups based on CO_2 captured from point sources.

1. Transporting power to a source of carbon and co-locating both hydrogen electrolysis and the subsequent transformation process

In this study we distinguish between large point sources and small-scale CO_2 sources with CO_2 at high CO_2 concentration.

Production of carbon-containing e-fuels, co-located with large point sources of CO_2 can be identified on a specific site-basis. All above-mentioned aspects with respect to e.g. electricity price and CO_2 quality, water availability, as well as by-product and heat revenues, are set by the site conditions. The large point sources of CO_2 allow for relevant amounts of e-fuel production making use of economy of scale effects. Thus, this category, represented by CO_2 sources that are larger than 100 kton/year, has been the starting point for the siting analysis (see Section 4.2.1). Using this starting point is also supported by the analysis included in Section 4.2.2.

Production of carbon-containing fuels co-located with small scale CO_2 sources with CO_2 at high concentration, e.g. biogas plants, has the same site-dependent character (electricity price, water availability, by-product and heat revenue etc.) as the category above. However, the number of potential small-scale CO_2 sources is very large and a register specifying exact sites is not available. The principal advantage is the fact that CO_2 is already upgraded within these plants, avoiding investment in carbon capture units. Difficulties arise with respect to small scale operation and associated high specific costs. An analysis of production cost for this category based on generic data available in literature, where it has already been studied, is presented in Section 4.2.3, including a literature review to relate the potential of small-scale e-fuel production at biogas plants to the large-scale siting analysis performed in the present project.

2. Transporting hydrogen produced at a separate location to a source of carbon for final transformation

This option allows hydrogen to be produced where power is cheap. Producing hydrogen at locations with high availability of low-price electricity and the transporting hydrogen to the location of a suitable CO_2 source makes it possible to more freely combine favorable siting conditions. To what extent this option provides a cost-efficient solution is directly dependent on the relative costs of transporting hydrogen and electric power. Therefore, this relation has been studied separately, on a case study basis, and described in Section 4.2.2. The conclusion is that locating hydrogen production at the CO_2 source – corresponding to the first category – is the most cost-efficient near-term solution. As a result, this category is not analyzed in further detail as part of this study.

3. Transporting carbon to the production site and co-locating both hydrogen electrolysis and the subsequent transformation process.

This allows for production at locations that might benefit from, for example, low power prices or a high willingness-to-pay for any excess heat or oxygen created by the e-fuel production process. This option is dependent on the future development of infrastructure for CO_2 transport, but is unlikely to be relevant in the near- to medium-term.

4.1.2 Production of carbon-containing fuels based on direct air capture

Production of carbon-containing fuels based on direct air capture has identical site requirements as hydrogen, except when it comes to product markets, in which it is identical to other production routes for the same fuel. Further, the production costs will at all sites be considerably higher than other options. Consequently, conclusions regarding siting of this category can be drawn directly from the analysis of other options, without a detailed analysis of this category specifically. This category is thus, apart from here, only briefly included in Chapter 6.

4.1.3 Production of non-carbon e-fuel, i.e hydrogen

Production of hydrogen is not linked to the availability of CO_2 sources at all, but more dependent on power and product markets. However, the methodological approach used to assess production costs of hydrogen at large CO_2 point sources nevertheless provides useful information on the relative attractiveness of various sites since it includes analysis of all of the relevant siting conditions (see Section 4.2.1, for more detail).

It should be noted that distributed hydrogen production, for example at refueling stations, is also a possibility. However, as this production model effectively dispenses with the need to identify specific production sites, it is outside the scope of this project.

4.2 Methodology

4.2.1 Site identification based on CO_2 point sources

For fuels requiring carbon dioxide (i.e. methanol, DME, methane and FT-liquids) the approach adopted in this project was to assume that e-fuel production plants will be co-located with large CO_2 point sources. This makes sense both from a production cost perspective (CO_2 capture from point sources is cheaper than air capture; co-location with large CO_2 sources allows for large-scale plants giving economy of scale benefits) and from an infrastructure perspective (existing industrial sites will have infrastructure for transportation of feedstock and product, network capacity for electricity supply, water handling systems etc.)

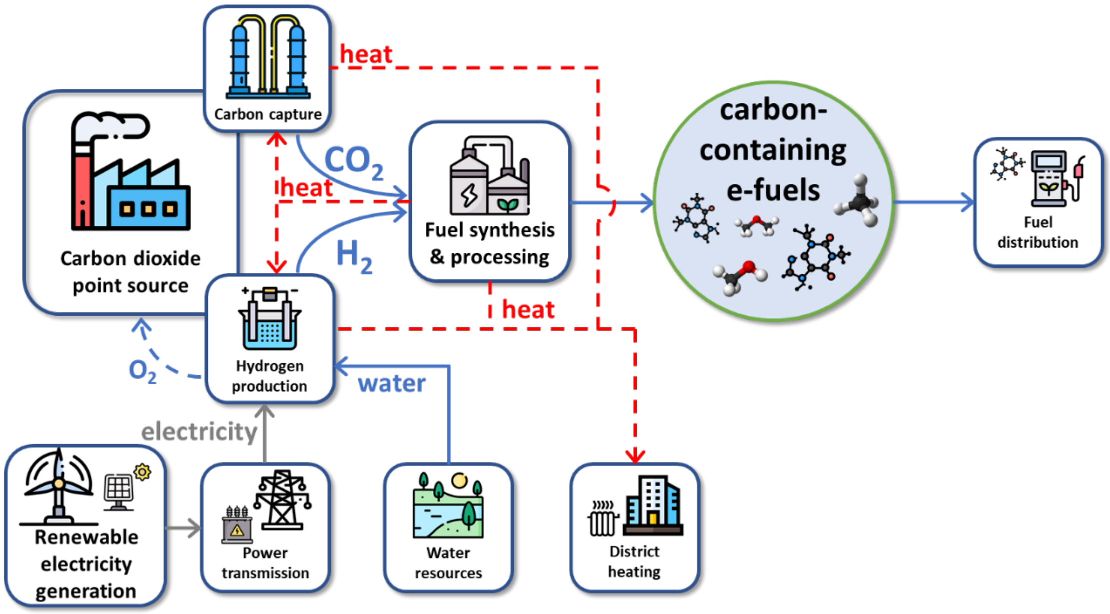

Figure 4.1. Illustration of production of carbon-containing e-fuels at large-scale CO_2 point sources.

Potential production sites – i.e., CO_2 point sources – were identified using the European Pollutant Release and Transfer Register (E-PRTR) [15]. This register is kept by the European Environment Agency and contains information on the release and transfer of 91 key pollutants by industrial facilities located in the European Union member states and in Switzerland, Iceland, Liechtenstein and Norway. For each of the 91 pollutants covered by the register, any industrial facility emitting amounts above certain threshold values are required to report emissions annually to the register. For emissions of carbon dioxide, the emission threshold is 100 000 tonnes per year and applies to the *total* CO_2 emissions of the facility (i.e., including both fossil and biogenic emission). However, facilities reporting CO_2 emissions to the register also report *fossil* CO_2 emissions separately.

Compared to other records containing information on CO_2 point sources (e.g., the European Emissions Trading System – EU ETS [16] – or records kept by national agencies) there are several benefits to using the E-PRTR in the present project. Most importantly, the E-PRTR contains biogenic as well as fossil CO_2 emissions, while most other records only track fossil emissions. The E-PRTR also contains coordinates for all included sites thus allowing for their efficient mapping, which is a prerequisite for assessing water availability (see Section 5.4) and power prices (see Section 5.6).

In addition to total CO_2 emissions, the following data were obtained from the register:

- Site name
- Site location (coordinates; city; country)
- Fossil and biogenic CO_2 emissions
- Industrial branch/activity (by E-PRTRs classification, see [15])

All sites included in the register in 2017 (i.e., emitting more than 100 000 tonnes CO_2 in 2017) were chosen for evaluation in the present work. By comparing the list of sites to the EU ETS registry, national records, and older versions of the E-PRTR (2015 and 2016) a few sites missing from the E-PRTR were identified and added, and a few discrepancies in the E-PRTR were corrected. After these corrections, a total of 232 sites were identified for evaluation in the present work. The sites are distributed over the entire Nordic region (see Figure 4.2) and a complete list of sites – including comments regarding changes made to the 2017 data obtained from E-PRTR – is available in Appendix 9.1.

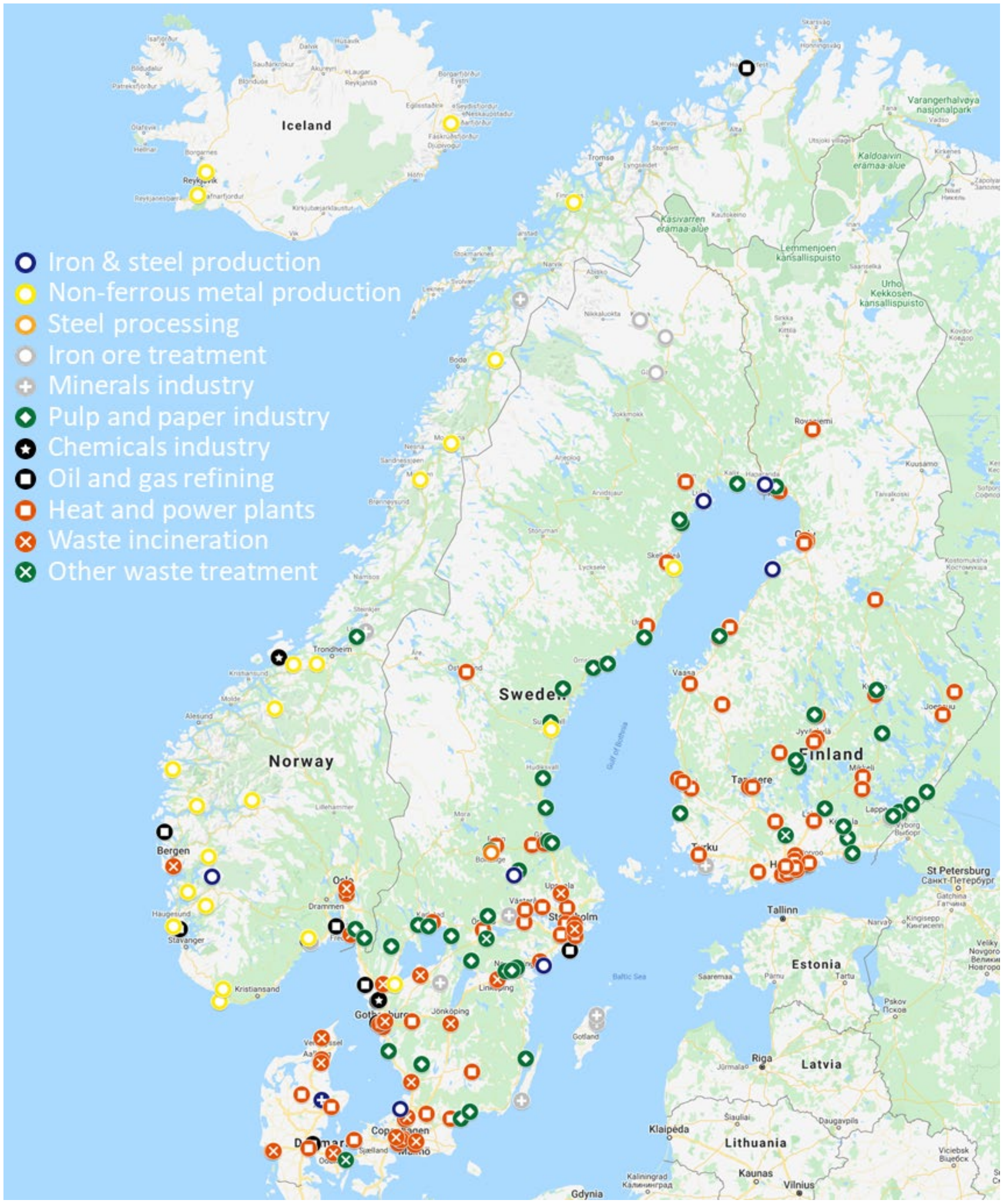

Figure 4.2. The 232 investigated sites for e-fuel production, categorised by industrial activity according to the E-PRTR classification.

4.2.2 Case study of onsite versus offsite hydrogen production

As noted in section 4.1, there are multiple alternative production setups that could be used to produce e-fuels. The work of this study focuses primarily on setups that involve the colocation of electrolysis capacity with existing carbon sources. However, we wanted to check that such a setup was economically rational and, specifically, whether it was not less costly to electrolyse hydrogen at a separate location and then transport this hydrogen to the carbon source for any subsequent transformation.

Importantly, we did not assess the socio-economically optimal setup for the hydrogen economy more generally.

The key factors involved in this comparison are the relative costs of electricity at different locations, since remote electrolysis might allow for access to cheaper power, and the relative costs of transporting power and hydrogen.

Specifically, we contrasted setups in which:

1. Hydrogen production is collocated with the e-fuel production facility and a point source for carbon (onsite production), and
2. Hydrogen is produced close to the point of power generation and then transported to the ultimate e-fuel production facility (offsite production).

These two setups are shown graphically below.

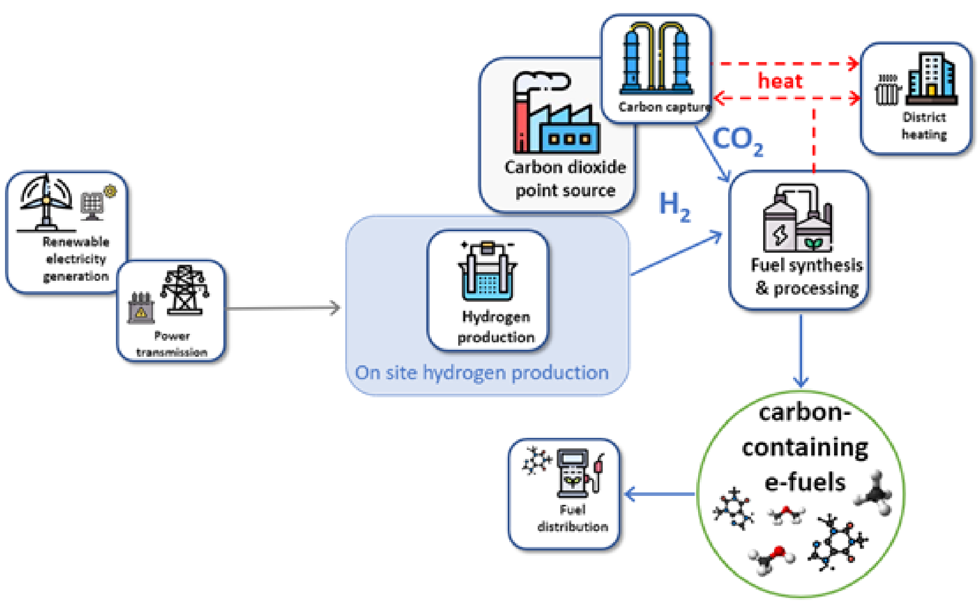

Figure 4.3: Onsite hydrogen production

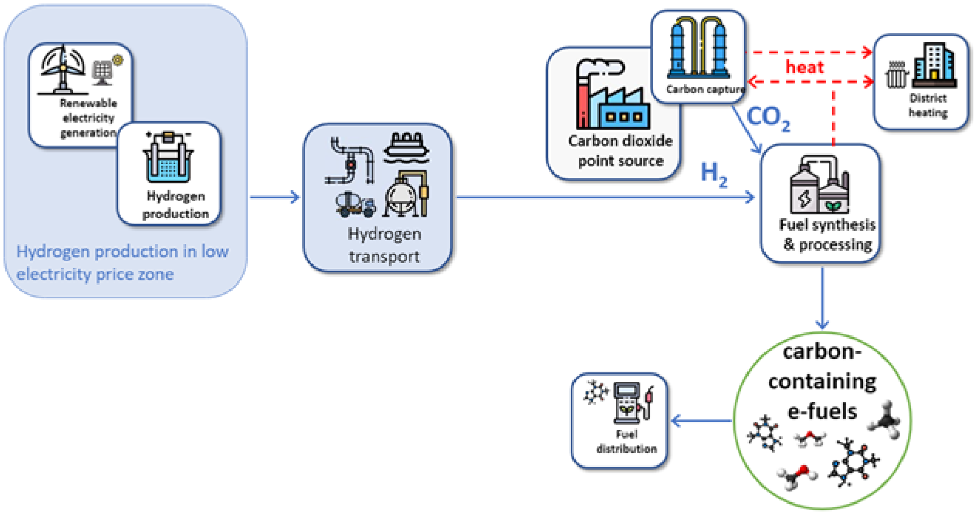

Figure 4.4: Offsite hydrogen production

Thus, energy is principally transported as either electricity or hydrogen depending on the setup. In some cases, we have erred on the side of underestimating the costs of transporting hydrogen, as discussed further below, but overall conclude that transporting hydrogen appears to be the more costly approach for the cases considered.

The analysis consists of a case study in which all cases produce the same volume of fuel. The specific locations examined for P2X production reflect relatively attractive sites in an area with low electricity prices (Luleå, Sweden)[11] and an area with high electricity prices (Aalborg, Denmark). These sites were selected because we wanted to see whether the least cost setup might vary depending on the local cost of electricity.

Six cases were analysed in total, three for each location. These three variants covered onsite hydrogen production and offsite production sourced from Iceland and Norway respectively.

[11] Luleå happens to be the site of the HYBRIT project, which seeks to pilot low-carbon steelmaking through the use of hydrogen. However, for the purposes of these calculations, the Luleå site has been chosen simply to reflect a typical attractive CO_2 point source in a low-power-price region. As such, the specifics of the future development of the HYBRIT project have been excluded from the analysis.

Further details on the various cases are summarised in the table below

Case 1: Onsite hydrogen production close to factory site in Luleå, Sweden • **Includes a buildout of 40 km of power distribution grid, including a high voltage transformer connected to the regional grid.**
Case 2: Offsite hydrogen production in Iceland and transport by ship and pipeline to factory site in Luleå, Sweden • Includes investments in storage and conversion infrastructure in Iceland, as well as costs for ship transport. • Includes investments in 20 km hydrogen grid (built through a rural area) for 'last mile' transport of the hydrogen to the factory. • The ship transport costs are estimated for a distance of 1000 km, although the actual route is around 3500 km. (Lower bound cost) • No cost is assumed for conversion of the hydrogen from liquid to gaseous form. (Lower bound cost)
Case 3: Offsite hydrogen production in Raggovidda, Norway and transport by truck to factory site in Luleå, Sweden • Includes investment in compressor at Raggovidda, as well as costs for truck transport. • The truck transport costs are estimated for a distance of 700 km, though the actual route is around 800 km. (Lower bound cost) • Includes investments in a 20 km gas grid for 'last mile' transport of the hydrogen to the factory.
Case 4: Onsite hydrogen production close to factory site in Aalborg, Denmark • Includes a buildout of 6 km of power distribution grid. • No transformer is needed, only an outgoing feeder to connect to an existing transformer.

Case 5: Offsite hydrogen production in Iceland and transport by ship and pipeline to factory site in Aalborg, Denmark

- Includes investments in storage and conversion infrastructure in Iceland, as well as costs for ship transport.
- Includes investments in 20 km gas grid (built through an urban area) for 'last mile' transport of the hydrogen to the factory.
- The ship transport costs are estimated for a distance of 1000 km, while the actual route is around 1600 km. (Lower bound cost)
- No cost is assumed for conversion of the hydrogen from liquid to gaseous form. (Lower bound cost)

Case 6: Offsite hydrogen production in Raggovidda, Norway and transport by ship to factory site in Aalborg, Denmark

- Includes investments in storage and conversion infrastructure in Raggovidda, as well as costs for ship transport.
- Includes investments in 20 km gas grid (built through an urban area) for 'last mile' transport of the hydrogen to the factory. The ship transport costs are estimated for a distance of 1000 km, while the actual route is around 3000 km. (Lower bound cost)
- No cost is assumed for the conversion of the hydrogen from liquid to gaseous form. (Lower bound cost)

It is very important to note that this analysis assumes that, to the extent that deeper electricity network reinforcement is needed, these costs are not passed on to the e-fuel producer. In contrast, the e-fuel producer must support investment along the fuel length of the hydrogen transportation chain. As such, this case study does not seek to identify the optimal socio-economic setup, it only tests the economic rationality of the assumed colocation production setup by contrasting it against an alternative in which remote hydrogen production is used to access lower cost power. In a scenario in which the hydrogen economy is more developed, and parts of the infrastructure are already built to serve an established hydrogen market, the necessary hydrogen infrastructure investments might be significantly lower.

We identified the infrastructure requirements for each case and calculated its total costs. Details on infrastructure costs can be found in the appendix. All cases include the same CAPEX and OPEX assumptions for the electrolyzer, excepting electricity costs, and consequently, these costs are not shown as a part of the results. The power grid investments were approximated using the power grid map provided by ENTSO-E[17], combined with various cost sources. An illustration of the suggested grid investments can be found in the respective Excel sheet that is part of the database[12]. The infrastructure costs were annualized, and added to the electricity opex costs to provide an annualised cost estimate under different years. Investment costs for power grid infrastructure are annualised over a period of 40 years, while investments in hydrogen infrastructure have an assumed lifetime of 15 years. The shorter lifetime of hydrogen components is chosen to reflect a higher uncertainty regarding the long-term value of the investments. The required Return on Investments (ROI) is assumed to be 6% for all investments. It is important to note that the hydrogen related costs used in this analysis reflect current cost levels. As the P2X-facility and the hydrogen production site might not be up and running until after 2030, it is likely that the actual costs for the hydrogen value chain will be somewhat lower than shown in these cases.

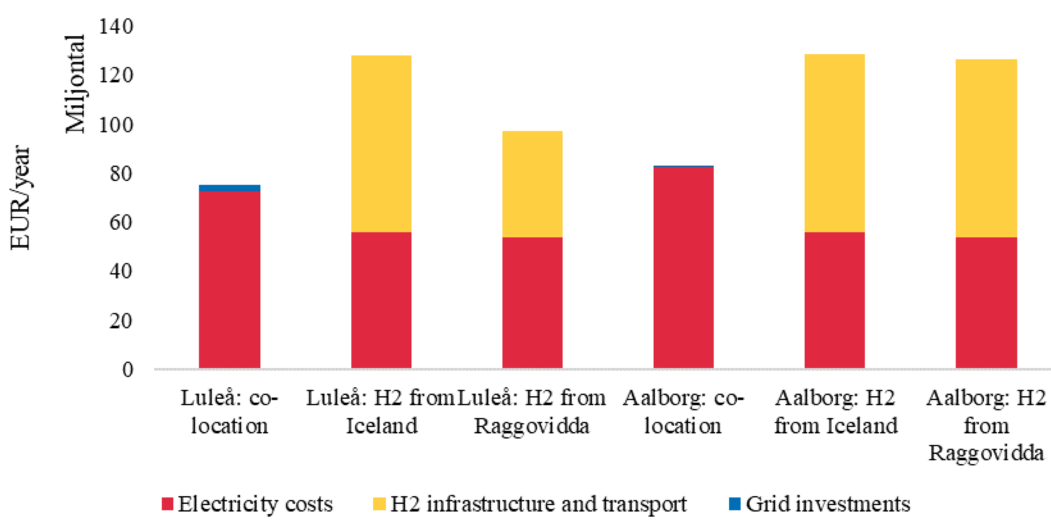

Figure 4.5: Cost of hydrogen production.

As shown in Figure 4.5, locating hydrogen production onsite at the P2X-facility is the cheapest solution, both for the Luleå and the Aalborg cases. The additional

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[12] A database used as basis for the calculations within the present project is publicly available at: www.nordicenergy.org/project/np2x/

investments needed to facilitate transport of hydrogen from Iceland or Raggovidda are far greater than the implied savings from lower cost power. Investments in the power grid are included both for the Luleå and the Aalborg co-location cases. For the Aalborg case, the annualised investment costs are too low to be visible in the figure, as they amount to less than 200 000 EUR/year. For the Luleå case, the annualised grid investments are significantly higher, lying somewhat above two million EUR/year. This is still very low compared to the necessary investments related to hydrogen transport and storage, which end up between 40 and 70 million EUR/year across the different cases. This reflects an important assumption that the additional power network infrastructure required to enable onsite hydrogen production at these locations is fairly limited. This assumption is founded on an expectation that these sites are supplied from additional generation capacity added within the same bidding zone in order to ensure that the e-fuels produced qualify as renewable under the Renewable Energy Directive. This assumption is likely to be more robust in the case of Luleå, which is located in Northern Sweden, where the grid is primarily constrained in terms of its ability to export surplus power.

Although the price of electricity is lower when hydrogen is produced in Iceland and Raggovidda, this is not enough to make up for the high costs of transporting hydrogen, even given the relatively conservative assumptions on hydrogen transportation costs noted above. For offsite hydrogen production to become the preferred option under this analysis, the power price needs to go above 54 EUR/MWh in Luleå, and 76 EUR/MWh in Aalborg, assuming unchanged power prices in Iceland and Raggovidda. As a reference, THEMA estimates a power price of 38 EUR/MWh in Luleå and 45 EUR/MWh in Aalborg.[13] Note that a sensitivity analysis was done to test whether these conclusions would change if one assumed a lifetime of 40 years for the hydrogen components. The sensitivity analysis shows that an increased component lifetime does not impact the results sufficiently to change the conclusion in any of the cases.

It is important to note that the results of this analysis reflect the specific question analysed, namely whether a P2X site with existing power infrastructure should prefer local generation and electrolysis to importing hydrogen produced at a distant, cheaper generation source assuming that it must bear the full costs of the necessary hydrogen transport infrastructure. As such, these results should not be read to

[13] Estimated power prices for 2035, using PPAs specifically

conclude that electrolysis close to low-cost generation and then hydrogen transport is less cost-efficient generally. Indeed, other studies have suggested that centralised hydrogen production and hydrogen transport entails lower socio-economic costs than power transmission.[14]

A summary of the key assumptions underpinning the cost analysis conducted above and the relevant sources is provided in Appendix 9.5. A further description of assumptions and sources can be found in the respective Excel sheet sheet that is part of the database[15].

4.2.3 Case study on e-fuel production based on biogas plants

Biogas plants with biogas upgrade to biomethane quality offer an interesting potential for making use of the separated CO_2 stream – being currently vented to the atmosphere – in order to:

- Increase the carbon conversion efficiency of the biogas plant making use of all carbon feedstock
- Using renewable, intermittent electricity (alternatively renewable hydrogen, if produced elsewhere), storing it in chemicals
- Further upgrade the produced methane to liquid fuels, either directly at the plant or in a central plant.

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[14] See, for example, [25].
[15] A database used as basis for the calculations within the present project is publicly available at: www.nordicenergy.org/project/np2x/

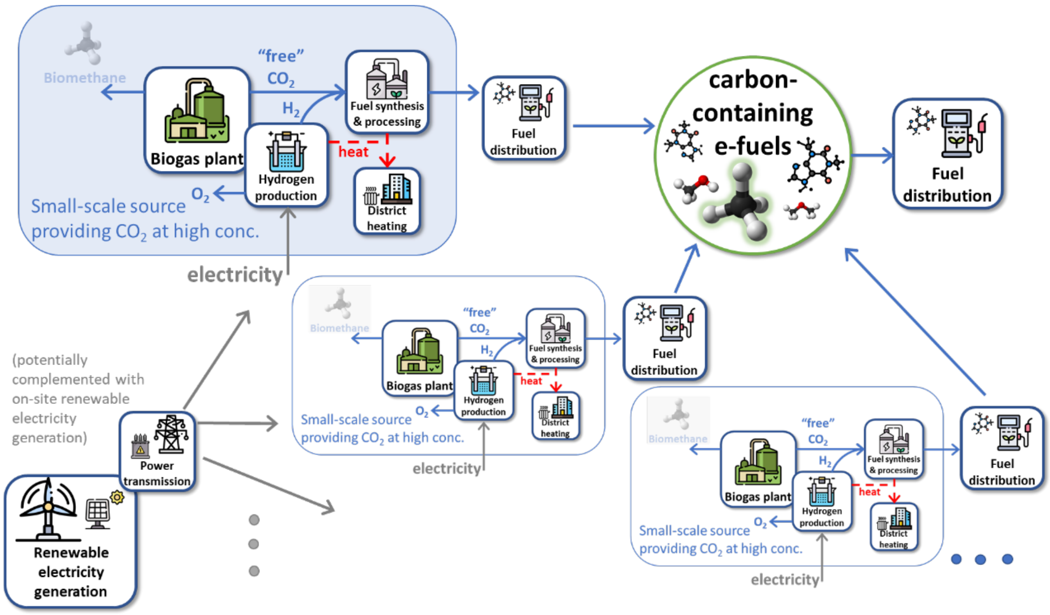

Figure 4.6: Illustration of e-fuel production scenario at multiple small-scale sites.

Several studies have considered this approach and there exist a number of initiatives testing further upgrade of biogas using hydrogen. Villadsen et al. [18] introduce the terminology "second-generation upgrading" for describing the increased use of carbon feedstock from biogas plants even making use of the CO_2 stream. Options for upgrading include biomethane – via catalytic, biological, or photosynthetic upgrade – or biomethanol production. The latter option even considers conversion of the produced methane from anaerobic digestion into methanol, leading to a liquid fuel product at farm scale. Peters et al. [19] also point out methanol as a promising fuel product at biogas farm scale plants. The need for simple processing chains in order to keep down the investment and operating costs favours methanol production, with a potential upgrade of methanol in a larger, central plant.

Examples of demonstration plants and concepts include biological methanation of CO_2 at biogas plants that has been demonstrated in Denmark[16], as well as CO_2 from ethanol production in Finland[17]. Other concepts being proposed on a commercial level

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[16] https://biocat-project.com/ (accessed 2020-05-20)
[17] https://www.st1.com/q-power-and-st1-piloting-synthetic-fuel-production-from-biorefinery-carbon-dioxide (accessed 2020-05-20)

include Fischer-Tropsch fuel production from municipal biogas plants as proposed by e.g. Renovare Fuels[18], but no existing plants are in operation to our knowledge.

The economic aspects of e-fuel production in relation to biogas plants have been investigated by Kouri et al [20] using electrolysis for increasing biomethane yield from biogas plant. They conclude that only under very optimistic assumptions (revenues for by-product oxygen and high price level for heat) small scale e-methane production becomes economically feasible. A recent study [21] points out biomethane-based jet fuel production as an attractive option for low-carbon aviation fuels that could become economically viable in the medium term. Different setups of large-scale central jet fuel production from remote biogas sources and additional CO_2 for carbon-efficient conversion are proposed. The revenues from co-generated heat as well as by-products contribute to a large extent to the economic performance. In addition, risks associated to the dependency on biogas production, being spatially distributed as well as being dependent on subsidies itself, are acknowledged. The superior environmental performance of biogas-based jet fuel over forest biomass-based fuels is stressed as a major benefit, due to biogas production being based on societal waste streams.

To relate the opportunities of biogas-based e-fuel production to the large-scale production assessed as part of the siting analysis, production costs for e-methane at small to medium scale is assessed using the same economic framework.

By co-locating e-fuel production with a biogas plant, almost pure CO_2 is available from the biogas production process and can be utilised for e-fuel production at a very low cost. However, the amount of CO_2 available from biogas production plants is generally very small compared to the large industrial point sources that are the main focus of this work, meaning that specific CAPEX will be higher due to economy of scale effects. Below, electromethane production using CO_2 from biogas plants is compared with production at large industrial point sources.

The evaluation of production costs is based on the assumptions described in Section 5.1-5.5, with the exception that the cost for CO_2 capture at the biogas plants is assumed to be zero. Further, the amount of CO_2 available from the biogas plants was assumed to be 145.7 ton/GWh biogas (based on [22]). Under these assumptions, a preliminary analysis indicated that electromethane production at biogas plants can be cost competitive to large-scale production in the same power price area, when

[18] https://www.renovare-fuels.co.uk/ (accessed 2020-05-20)

biogas outputs exceed roughly 50 GWh/yr. This is a large size for a biogas plant and most plants of that size are in Denmark or Southern Sweden, so the further analysis focused on those regions.

Figure 4.7 gives the supply curve (dotted, each dot representing a biogas plant) for electromethane production at the ten Danish plants with biogas capacity exceeding 50 GWh/year (based on [23]), and compares production costs to those achieved by one of the lowest cost industrial sites in Denmark (Aalborg Portlands cement production plant). As is illustrated in the Figure, the four biogas plants with lowest fuel production costs achieve lower specific fuel production costs than Aalborg Portland, but total production at these plants is below half of the production at the Aalborg plant. To match the total production of Aalborg Portland, higher cost biogas plants must be used, and total production costs will increase above the costs at Aalborg Portland. Also note that production costs significantly exceed those of the identified Nordic site achieving the lowest production costs (Equinor Tjeldborgoddens methanol plant in Norway, indicated in red).

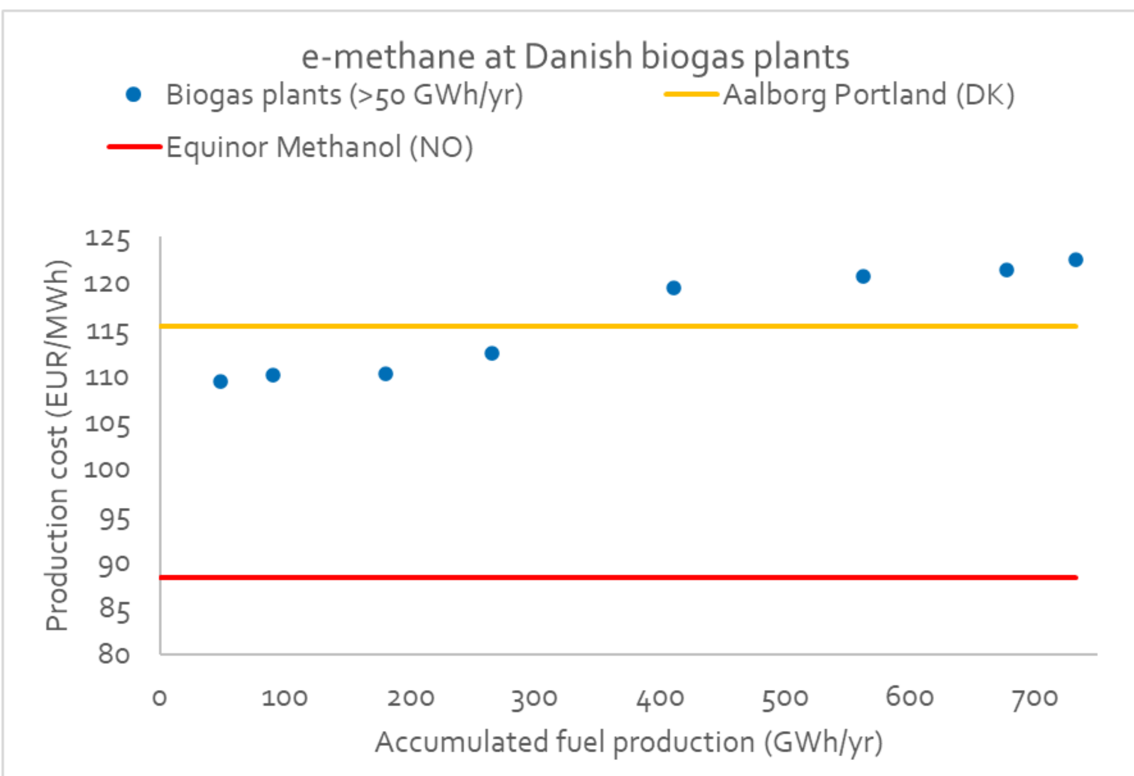

Figure 4.7. Comparison of electromethane production costs at Danish biogas plants and a low-cost Danish industrial point source (Aalborg Portland). The least-cost production site in the Nordics (Equinor Tjeldbergodden Methanol) is included for comparison.

For biogas plants in southern Sweden the situation is similar. This is illustrated in Figure 4.8, which compares e-methane production at the eight biogas plants in southern Sweden with biogas production capacity exceeding 50 GWh/year (based on [24]), to production at a large-scale point source in southern Sweden (the St1b refinery in Gothenburg). Again, small volumes of e-fuel can be produced at low cost at the best biogas plants, but to match the production at the refinery, biogas plants with higher production costs must be used and total fuel production costs will increase above those achieved at the refinery site. Note that e-methane production using CO_2 from the eight Swedish biogas plants with biogas capacity >50 GWh/year only gives around 550 GWh/ year of e-methane, while the St1 refinery has a production capacity exceeding 700 GWh/year.

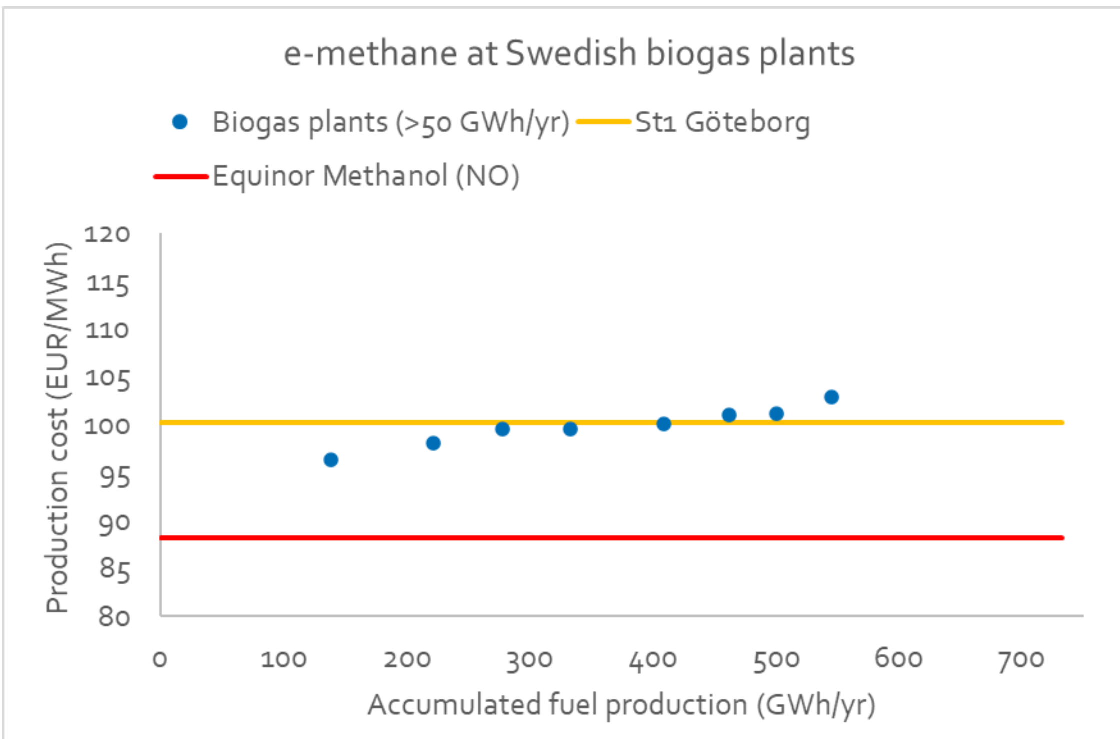

Figure 4.8. Comparison of electromethane production costs at at biogas plants in southern Sweden and a low-cost industrial point source in southern Sweden (St1 Göteborg). The least-cost production site in the Nordics (Equinor Tjeldbergodden Methanol) is included for comparison.

In conclusion, decentralised production of e-fuels using CO_2 from large biogas plants can be cost competitive to larger scale production in the same price area. However, the amounts that can be produced at competitive costs is limited. Further, large-scale biogas plants are mostly located in southern Sweden and Denmark, where power prices are comparatively high. Consequently, production at the biogas plants in these areas will perform worse when compared to large industrial point sources lower power price regions such as Norway or northern Sweden.

4.2.4 Hydrogen production using offshore wind power

Two recent Danish reports have pointed out the potential benefits of locating hydrogen production close to offshore wind power generation. [25], [26] The main reason for doing so is that transporting hydrogen in a dedicated pipeline could be more cost efficient that investing in more power grid capacity in scenarios where hydrogen demand picks-up considerably. The electrolysis capacity could either be sited offshore on a so-called energy island or else close to the landing site for the power generated offshore. The hydrogen produced could then either be used as feedstock for e-fuel production or else distributed elsewhere for use in various hydrogen applications. These reports also note that large central production units for hydrogen production could be an enabler for developing hydrogen infrastructure, which will itself be necessary if hydrogen and e-fuel applications are to be rapidly deployed.

4.2.5 Blue hydrogen

This study focuses on the production of e-fuels, which make use of hydrogen produced using electricity. More specifically, the focus is entirely on hydrogen produced from renewable electricity, so called Green Hydrogen. As noted previously, the development of e-fuels will be affected by wider developments in the hydrogen economy. In this regard, it is important to note that low-carbon hydrogen could also be produced at scale by steam methane reforming (SMR) or auto-thermal reforming (ATR) of natural gas combined with CCS, so-called Blue Hydrogen. In literature the upper limit for the capture rate is often assumed at 85-90% for SMR and above 90% for ATR. However, this hydrogen will not be renewable.

The relative competitiveness of hydrogen from electrolysis and hydrogen from natural gas with CCS depends on the trajectory of growth in hydrogen demand, technology and infrastructure development. The literature indicates that large-scale production of hydrogen from natural gas with CCS is possible at a lower cost than hydrogen from electrolysis in the short to medium term. Hydrogen Council estimates that cost of Blue hydrogen in Europe could drop from 2,1 USD/kg inn 2020 to 1,8 USD/kg in 2030, while hydrogen production based on offshore wind could from a current level of 6 USD/kg to 2,5 USD/kg in 2030. [27], [28] However, if hydrogen consumption is decentralized (e.g. in transport), the cost of distribution might be higher for hydrogen from natural gas with CCS as it is more dependent on scale to achieve cost reductions than electrolysis. Over time, some studies point out that the reduced cost of electrolysis and renewable power generation could make hydrogen for electrolysis increasingly competitive.

To the extent, that blue hydrogen penetrates the hydrogen market, siting of production of synthetic fuels would be located close to the production sites for blue hydrogen.

4.3 Methodological approaches based on ranking perspective

4.3.1 Fuel production cost ranking

The cost ranking of sites for the production of carbon-containing e-fuels, co-located with large point sources of CO_2, and for large-scale production of hydrogen (see below), is based on the E-PRTR site list described in Section 4.2.1**.** Based on this list, a database has been created including all relevant cost data for each specific site. The type of costs included are:

- Capital investment costs and operational costs for electrolysis unit, carbon capture unit and fuel synthesis plant
- Costs of process inputs, such as electricity (and heat)
- Potential revenues from by-products such as oxygen and heat.

The input data and assumptions used for all these cost items are described in Chapter 5. The production of renewable e-fuels is directly linked to the availability of renewable electricity production and the cost of electricity is vital. The power system is a complex system in itself and the development of electricity price highly system dependent. Further, the REDII regulations linked to the accounting of renewable electricity shares have a major impact. Therefore, the development of electricity cost is based on the TheMa power market model of the Nordic power system and the extraction of prices from this model has been adapted to the REDII provisions. The methodological details are further described in Section 5.6.

Cost data are introduced in the database separately for the all the fuels included in the study (i.e. methanol, DME, methane, FT-liquids, and hydrogen) as well as for the three different years in focus (2025, 2035 and 2045).

For the e-fuel hydrogen, a CO_2 supply is not necessary and potential production sites are not determined by CO_2 availability. However, as noted above, hydrogen production was in this project still only evaluated at the sites that were considered for production of carbon containing fuels. While this imposes an unnecessary constraint on potential production sites, the investigated point sources cover all electricity price areas and offer widely differing potentials for utilisation of the by-products heat and oxygen (see below). Consequently, the production cost range for these sites is expected to closely match the production cost range for all possible sites in the Nordics.

By introducing cost data, as described above, for all the specific sites in the database a full ranking of sites for all fuels and all years is possible. However, because of uncertainty in data input one should be careful in drawing conclusions based on the exact ranking position of a specific site. Rather, in drawing results from the database, focus is put on identifying the major factors impacting the ranking as well as the larger cost steps between types of production sites.

4.3.2 Greenhouse gas emission reduction ranking

Potential production sites are ranked by their GHG emission reduction potential, evaluated according to RED II sustainability criteria for all fuel alternatives in relation to their corresponding fossil counterpart.

Currently, the sustainability criteria for e-fuels are still in development phase, and as described above, the methodology for assessing greenhouse gas emission savings for this type of fuels is not yet specified. For the purpose of this project, the current RED II methodology for transport fuels is applied. The assumptions made concerning the aspects not yet covered by RED II calculation rules are explained below in Section 5.7.

Using the RED II methodology, the potential emission savings are almost entirely determined by the carbon intensity of electricity supply and to some degree by the potential for heat exports, which allows emission allocation based on energy content. While electricity emission factors mainly differ between *countries,* the potential for heat exports can vary significantly between production sites, implying that a site-specific ranking (and not just a ranking of the Nordic countries) is possible also from a GHG perspective.

The calculation of GHG emissions for each specific site is integrated in the e-fuel production site database (see above).

4.3.3 Infrastructure aspects ranking

The infrastructural conditions are highly relevant to the siting of e-fuel production. There are, however, different types of infrastructural aspects that impact the siting differently. In this study they have been grouped into three types:

- **Production-related infrastructure**, including the availability of network capacity for electricity supply, water availability and treatment facilities and the linkage to by-product markets such as oxygen and heat demand near-by. These infrastructural aspects are all site specific. Further, the quantitative cost aspects related to them are mostly already included in the cost ranking of sites.
- **Fuel distribution infrastructure**, mainly including the need for adding infrastructure for distribution of fuel from the production site to fuel users (filling stations). This infrastructure is both dependent on type of fuel and on the specific production site and its remoteness to demand centers.
- **Transport infrastructure,** including refueling station infrastructure or vehicle drivetrains which are directly related to type of fuel rather than production site. These infrastructural aspects are not covered in the present project.

The ranking impact of infrastructural aspects is further discussed for the first two of these types. However, in addition to infrastructural related cost data already included in the cost ranking, quantitative data for the time period and specific sites of this study would be too time-consuming to gather and too uncertain to be relevant. Therefore, a more qualitative methodology was used for the ranking of sites based on infrastructural aspects and the data behind this ranking is not included in the site specific e-fuel production database[19].

For production-related aspects the analysis has been limited to a general discussion, linked to principal types of locations, rather than a ranking as such. Ranking of sites based on fuel distribution infrastructure has been made in relation to both type of e-fuel produced and type of site location. Further, the implications of this principle ranking for the top ranked sites based on cost and GHG emissions are discussed.

5 Input data and assumptions

To identify and evaluate the potential e-fuel production sites in the Nordics according to the ranking criteria mentioned above, a number of underlying assumptions and models have been used. The major input data and assumptions for the respective

[19] A database used as basis for the calculations within the present project is publicly available at: www.nordicenergy.org/project/np2x/

areas are given in the following sections. A worked example of fuel production cost calculations is available in the report Appendix (Section 9.7).

5.1 E-fuel production

The conceptual process flow chart of a general e-fuel production plant is presented in Figure 1.1, illustrating the most important sub-processes (electrolysis, carbon capture and fuel synthesis), process inputs (electricity, water and carbon dioxide) and outputs (e-fuel, heat and oxygen). This sub-chapter describes the sub-processes electrolysis, carbon capture and fuel synthesis and technical assumptions made for their modelling in the present work. Resulting mass and energy balances for all fuels are given in Section 5.1.4.

The e-fuel plants are assumed to operate at 80 % capacity utilization. The size of the e-fuel plants is constrained by the size of the CO_2 source and an upper size limit of 200 MW_{el} imposed on the electrolyser (corresponding to roughly 100 MW fuel production). The electrolyser size limit corresponds to an annual CO_2 utilisation of roughly 200 ktonnes, meaning that only parts of the available CO_2 will be utilized for industrial sites with emissions exceeding 200 ktonnes/year. For hydrogen production, a 200 MW_{el} electrolyser is considered for all investigated sites.

5.1.1 Electrolysis

During electrolysis of water, water reacts to form oxygen and hydrogen. This reaction is performed in so-called electrolysis cells and consumes energy which is supplied to the cell in the form of electricity and, in some cases, heat. The electricity demand of the electrolysis reaction is given by the change in Gibbs free energy (ΔG = 237.2 kJ/mol H_2 at standard conditions), while the heat demand is given by the term $T\Delta S$ (48.6 kJ/mol H_2). At increasing temperatures, ΔG decreases while $T\Delta S$ increases. Consequently, the electricity consumption of the electrolysis cell can be decreased at the expense of increasing heat demand by operating at higher temperatures. Electrolysis cells are generally divided into low-temperature cells (approximately 20-90°C) and high temperature cells (800-1000°C). In low temperature cells, heat generation due to losses at the cell electrodes exceed the heat demand of the reaction, implying that electricity is the only energy input and that cooling is required. Conversely, in high temperature cells, heat must be added to the cell in order to cover the reaction heat demand. [29]–[31]

There are two main low temperature technologies – alkaline electrolysis and PEM (Proton Exchange Membrane) electrolysis – of which the former can be considered more mature in large-scale installations. On the other hand, high-temperature technologies are still in early stages of development. [32]

Two technologies for hydrogen production were considered in this report. For a base case, the more established technology of alkaline electrolysis was chosen, while the developing high temperature technology SOEC is discussed in relation to the ranking results Section 6.1.1. The conversion efficiency of both alkaline electrolysis technologies was assumed to increase over the studied period (2025-2045). For 2025, operating parameters were based on [32] and are given in Table 5.1, below. The alkaline electrolyser efficiency was assumed to increase by 5 %-points in 2035 and by an additional 5 %-points in 2045. The excess heat of the alkaline electrolyser has been adjusted accordingly.

Table 5.1. Assumed operating parameters for alkaline electrolysers.

Alkaline electrolyser	**2025**	**2035**	**2045**
Power demand ($MJ/MJ_{H2,LHV}$)	1.54	1.43	1.33
Power demand (kWh/kg_{H2})	51	48	44
Excess heat ($MJ/MJ_{H2,LHV}$)	0.46	0.35	0.25
Excess heat (°C)	60-80	60-80	60-80

5.1.2 Carbon capture

A multitude of technologies have been proposed for capturing CO_2 from the flue-gases emitted by industrial processes or heat and power plants, including systems for separation using e.g. membranes, pressure swing adsorption or cryogenic distillation of liquified gas. The most developed technologies are, however, based on separation using chemical solvents. These technologies rely on contacting the CO_2-containing gas with a liquid absorbent which selectively captures CO_2. CO_2 is then obtained from the absorbent by heating in a separate vessel (regeneration) and the regenerated absorbent is reused [33].

The specific size (i.e., per tonne of CO_2) of the necessary equipment, and the steam demand of the regeneration step, decreases with increasing CO_2 concentration in the flue-gas, implying that the costs of CO_2 capture decrease with increasing CO_2

concentration in the flue gases [34]. Potential process modifications that could increase CO_2 concentration, such oxy-fuel combustion and pre-combustion capture, are less relevant for industrial processes and have not been taken into account in this report.

CO_2 absorption from flue gas using a monoethanolamine (MEA) absorbent was selected as the technology for carbon capture from point sources in the present work, due to its commercial availability and benchmark status in the literature. The assumed operating parameters were based on [34] and [35], and are summarized in Table 5.2. Note that the process steam demand decreases with increasing CO_2 concentration in the flue gas.

Table 5.2. Assumed operating parameters for CO_2 capture using MEA-based CO_2 absorption.

	MWh/tonne CO_2	**Temperature (°C)**
Steam demand	$0.66 \cdot (\text{vol-\%}\ CO_2)^{-0.127}$	120
Electricity input	0.07	-
Excess heat	0.72	100–60

5.1.3 Fuel synthesis

Fuel synthesis from CO_2 and H_2 is similar to synthesis of fuels from syngas obtained from e.g. biomass gasification that has been extensively studied for biofuel production. The overall stoichiometry for the four e-fuel pathways is:

Methane:	$CO_2 + 4\ H_2 \leftrightarrow CH_4 + 2\ H_2O$	ΔH = -165 kJ/mol
Methanol:	$CO_2 + 3\ H_2 \leftrightarrow CH_3OH + H_2O$	ΔH = -50 kJ/mol
DME:	$2\ CO_2 + 6\ H_2 \leftrightarrow CH_3OCH_3 + 3\ H_2O$	ΔH = -123 kJ/mol
FT-liquids:	$CO_2 + 3\ H_2 \leftrightarrow -CH_2- + 2\ H_2O$	$\Delta H \approx$ -116 kJ/mol

The above reactions can proceed via different sub-steps, with the most important being the reverse water gas shift reaction:

Reverse water gas shift: $CO_2 + H_2 \leftrightarrow CO + H_2O$ ΔH =+41 kJ/mol

During FT-Liquids synthesis a range of products with varying chain length – varying from light hydrocarbons (CH_4, C_2H_6, C_3H_8, C_4H_8), naphta (C_5- to C_{12}-chains), kerosene-Diesel fuel (C_{13}- to C_{22}-chains), as well as low- and high-molecular-weight waxes – are produced. The chain length distribution is a function of catalyst and process setup and product upgrade is necessary to obtain the proper fuel blend(s) aimed at.

The overall reactions for fuel synthesis are exothermal, implying a loss in chemical conversion efficiency, but even allowing for using the generated excess heat for both upstream processes (e.g. carbon capture) and downstream product upgrade (e.g. water removal and removal/recycle of unwanted by-products). There exist a large number of possible process setups for the synthesis of the e-fuels, for more details see e.g. Hänggi et al. [36] or Brynolf et al. [32]

For the purpose of the present study, conversion efficiencies of the considered technologies for production of carbon-based fuels from hydrogen have been based on the work of Brynolf et al. [32] and are given in Table 5.3.

Table 5.3. Conversion efficiencies of e-fuel production technologies.

	Methanol	**DME**	**Methane**	**FT-liquids**
Conversion efficiency (LHV_{fuel}/LHV_{H2})	0.79	0.80	0.77	0.73

5.1.4 Overall mass and energy balances

Process inputs and outputs of the carbon-based e-fuel production plants are summarized in Table 5.4 below. For the integrated production chain it has been assumed that excess heat from fuel synthesis will be utilized for carbon capture, implying that the total steam demand of the carbon capture process equals the heat demand of the capture process less the excess heat from fuel synthesis. The excess heat from electrolysis and cooling of the carbon capture process was assumed to be available for export.

Table 5.4. Process inputs and outputs for production of the e-fuels considered in this report. Due to the assumed increase in electrolyser efficiency, three values are given for electricity input and electrolyser heat output (year 2025, 2035 and 2045, respectively).

	Unit per MWh fuel	**Methanol**	**DME**	**Methane**	**FT-liquids**	**Hydrogen**
Electricity input	MWh	1.95 1.81 1.69	1.92 1.79 1.67	2.00 1.86 1.73	2.11 1.96 1.83	1.54 1.43 1.33
CO_2 input	tonne	0.28	0.29	0.21	0.28	0

Steam demand[1,3]	MWh	0.14	0.15	0	0.04	0
Available excess heat[2,3]	MWh	0.78 0.64 0.52	0.79 0.65 0.53	0.75 0.61 0.48	0.83 0.68 0.55	0.46 0.35 0.25
Oxygen output	tonne	0.3	0.3	0.3	0.3	0.3
Steam demand (carbon capture)[3]	MWh	0.24	0.25	0.18	0.24	0
Excess heat (electrolyser)	MWh	0.58 0.44 0.32	0.58 0.44 0.32	0.60 0.46 0.33	0.63 0.48 0.35	0.46 0.35 0.25
Excess heat (synthesis)	MWh	0.1	0.1	0.2	0.2	0
Excess heat (carbon capture)	*MWh*	0.20	0.21	0.15	0.20	0

[1]*Carbon capture steam demand less excess heat from fuel synthesis*
[2]*Excess heat from electrolyser and carbon capture*
[3]*Assumes 13 vol-% CO_2 in flue gases, see Table 5.2*

5.2 E-fuel production costs

E-fuel production costs have been based primarily on the work by Brynolf et al. [32] which reviews published production cost estimates for several e-fuel production concepts, considering both present and future (2030) production costs. In this report, investment cost estimates have been based on the *present* costs given by Brynolf et al., with some adaptions made to electrolyser costs in 2035 and 2045 (see below). A worked example of fuel production cost calculations is available in the report Appendix (Section 9.7).

The financial parameters assumed in this report are:

- Interest rate: 5 %
- Plant lifetime: 25 years
- Plant utilisation: 80 % (7000 hours/year)

E-fuel production costs have been calculated using the cost function below which is a slight modification to the cost function proposed by Brynolf et al. [32]:

$$TC\left[\frac{€}{MWh}\right] = I_{electrolyser} + I_{fuel\,synthesis} + I_{CO2capture} + C_{stack} + C_{electricity} + C_{water} + C_{steam} + O\&M - P_{heat} - P_{oxygen}$$

The total production cost (TC) in €/MWh is made up of

- Annualised investment cost I_i for electrolyser, fuel synthesis plant and carbon capture unit, respectively
- Annual operating costs C_i for electrolyser stack replacement, electricity, water (cooling and process water) and steam (for carbon capture)
- Annual operation and maintenance costs, *O&M*
- Annual by-product revenues P_i

Investment cost items include both direct (equipment purchased) and indirect (installation, engineering, contingency etc.) costs. Direct investment costs for the electrolyser and fuel synthesis plants were primarily based on *present* costs given in [32] and developed into cost functions on the form

$$Investment\ (kEUR) = a \cdot (sizing\ parameter)^b$$

For the electrolyser, no economy of scale effects were assumed (i.e., *b=1*) which is in line with the assumption made in [32]. Since electrolyser plants of the size considered in this work (100-200 MW_{el}) have not yet been built the actual scaling factor is uncertain. However, given the modular nature of the technology (especially at large scale), using b=1 seems reasonable. Additionally, this is the value used by [32] for electrolysers up to twice the size considered in the present work. The investment costs given in [32] were considered high (1100 kEUR/MW power in 2025), given recent developments. Specifically, NEL Hydrogen recently received a purchase order from Nikola for an 85 MW unit with an order volume "in excess" of 30 MUSD, corresponding to about 300 kEUR/MW[20]. The Danish Energy Agency [37] adopts investment cost of 600 kEUR/MW for 2020 for alkaline electrolysers, decreasing to 550 and 500 kEUR/MW in 2030 and 2050, respectively. Given the wide range in cost estimates, the value of 600 kEUR/MW from [37] was used for 2025, while costs were assumed to be 25 % lower in 2035 and 50 % lower in 2045. Note however that the specific

[20] https://nelhydrogen.com/press-release/nel-asa-receives-purchase-order-from-nikola-2/ (accessed 2020-08-14)

electrolyser cost will be the same for all investigated sites and therefore not affect the cost-based site ranking.

For fuel synthesis, the cost function parameters given in Table 5.5 were developed to fit cost data given by Brynolf et al. for different plant sizes, and costs were assumed to be constant throughout the studied time period. **Note**, that for both the electrolyser and the fuel synthesis, indirect investment costs were taken as 100 % of the direct costs, indicating that the *total* investment cost is twice that given by the parameters in Table 5.5.

Table 5.5. Cost function parameters for calculating direct investment costs for electrolysis and fuel synthesis.

Equipment	Sizing parameter	a			b
		2025	*2035*	*2045*	
Alkaline electrolyser	MW power	600	450	300	1
Methane plant	MW fuel	970	970	970	0.7
DME plant	MW fuel	1710	1710	1710	0.7
Methanol plant	MW fuel	1710	1710	1710	0.7
FT-liquids plant	MW fuel	2220	2220	2220	0.7

Investment costs for carbon capture are not explicitly accounted for by Brynolf et al. and have instead been based on the work by Garðarsdóttir et al. [34] which gives cost functions for MEA based carbon capture for six different CO_2 concentrations in the flue gas ranging from 5-30 vol%. For each evaluated site, the cost function corresponding to the concentration closest matching that of the CO_2 source was used (see also Section 5.3 for information on CO_2 sources). The cost functions are on the form

$$\text{Investment [kEUR]} = \text{a} \cdot \left(\frac{CO_2 \text{ flowrate [kg/s]}}{CO_2 \text{ concentration [vol\%]}} \right)^{\text{b}}$$

and their parameters are given in Table 5.6 (including both direct and indirect costs). Note that the investment costs are assumed constant throughout the studied period.

Table 5.6. Cost function parameters for calculating total (direct+indirect) investment costs for carbon capture.

vol% CO_2	a	b
5	3080	0.60

9	3030	0.61
13	3350	0.65
20	5310	0.56
24	4170	0.65
30	3210	0.74

O&M are the operation and maintenance costs for the plant and calculated as 4 % of the *direct* investment cost (i.e., excluding indirect costs) for the electrolysis and fuel synthesis plant [32], plus 4 % of the *total* investment costs for the carbon capture plant [34].

The cost for electrolyser stack replacement, C_i (relevant for alkaline electrolysers) is the annualised cost for two stack replacements during the plant lifetime. The annualised cost of each replacement was assumed to equal 50 % of the annualised electrolyser investment cost, i.e. $C_{stack} = I_{electrolyser}$ for the two replacements.

Assumed prices for water, steam, oxygen, and excess heat are given in Table 5.7 and were taken to be constant throughout the studied period. Details on power prices can be found in Section 5.6.3. Corresponding annual costs or revenues were calculated based on the mass and energy balances described in Section 5.1.4, with by-product uptake limited by nearby demand as described in Section 5.5.

Table 5.7. Assumed utility and by-product prices. Power prices are treated separately in Section 5.6.3.

Steam (EUR/tonne)	Heat (EUR/MWh)	Oxygen (EUR/tonne)	Process water (EUR/tonne)	Cooling water (EUR/tonne)
17	25	50	1	0.02

5.3 Carbon dioxide sources

The overall approach to identifying CO_2 point sources for electrofuel production is described in Section 4.2.1. Besides location, the two properties of the CO_2 source that are of importance in this work are total annual CO_2 emissions and concentration of CO_2 in the emitted flue gases.

The total CO_2 emissions is one of the factors determining the size of the e-fuel plant (the other being the 200 MW_{el} upper bound on electrolyser input) and is therefore of importance for the cost ranking (due to economy of scale effects, see Section 5.2).

The CO_2 concentration in the flue gases affects the cost of the carbon capture process, with higher concentrations implying lower (specific) capture costs (see Sections 5.1.2 and 5.2).

Obtaining actual flue gas CO_2 concentrations for all sites investigated in the present work would be an extremely time-consuming task requiring individual contacts with process engineers at each site. Instead, CO_2 concentrations have been decided for each site using generic estimates based on the industrial activity indicated in E-PRTR (see Section 4.2.1).

The CO_2 concentration estimates are uncertain and instead of attempting to arrive at exact numbers, each industrial activity was sorted into the concentration category given in Table 5.8 which was judged to agree best with the actual CO_2 concentration. Note that the six CO_2 concentration categories in Table 5.8 correspond to the six concentrations for which detailed cost data has been obtained (see Section 5.2).

The CO_2 concentration assessments were primarily based on [34], although complementary sources have been used for e.g. non-ferrous metals production and some chemical plants. A more detailed table, including references and additional assumptions is available in Appendix 9.2.

Table 5.8. Estimated flue gas CO_2 concentration for the various industrial activities performed at potential e-fuel production sites.

vol% CO_2	Industrial activity
5	Aluminium smelters; silicon production; petrochemical cracking; heat and power plants (gaseous fuel); methanol production; iron ore treatment
9	Refineries without hydrogen production; heat and power plants (liquid fuel); copper production; ferrochrome production; steel processing; oxo-synthesis
13	pulp and paper; refineries with hydrogen production; heat and power plants (solid fuel); ethanol production
20	Minerals industry (cement and lime); iron production (direct reduction process)
24	Integrated iron and steel mills (blast furnace process); ferromanganese production; hydrogen production (steam methane reforming)
30	Ammonia production; TiO_2 production; secondary steel production

5.4 Water resources

The water availability in each potential production site was identified in the project. The water scarcity evaluation was based on AWARE-methodology (Available WAter REmaining) developed by WULCA-working group (www.wulca-waterlca.org). A multi-stakeholder group of water and LCA experts from academia, different industries and public institutions forms the WULCA working group, founded in 2007. The group focuses on water use assessment and water footprinting from a life cycle perspective. One of the main objectives of WULCA group is to provide harmonization towards freshwater use and water impact assessment. Publicly available AWARE water scarcity factors act as a tool in this harmonization work.

AWARE provides country specific and watershed specific values for water scarcity on monthly and yearly level, separately for agricultural and non-agricultural usage, considering the local availability and demand of water. The AWARE factors are in a range from 0.1 to 100, with a value of 1 corresponding to the world average, and a value of 10, for example, representing a region where there is 10 times less available water remaining per area than the world average. The factors are provided as a Google Earth layer (Aware v.1.2, April 2016), which was used for identifying the water scarcity in each potential site in the project.

The site-specific information was collected from the Google Earth layer as watershed specific non-agricultural factors.

In general, the Nordic Countries have good sources of water. This was also visible in the site specific information, when watershed specific non-agricultural factors were collected from the Google Earth layer for each site. In total, 232 locations were identified. 79 sites (34%) had a water scarcity factor <1.0; 120 sites (52%) between 1.0-1.9; 14 sites (6%) between 2.0-2.9; 11 sites (4,5%) between 3.0-5.9; and only 8 sites (3,5%) had a factor >10.0. The country average non-agricultural water scarcity factors for Nordic Countries are all below 2.0 (compared to European average of 5.9 and to Global average of 20.3 for non-agricultural water scarcity). In addition to the fresh water availability, the condensate water and/or desalinated sea water could be available at sites. Thus, the water scarcity is not expected to be a limiting factor for site selection.

5.5 By-product use

The potential by-products of the e-fuel process are heat and oxygen. While the amount of by-product produced per MWh fuel can be determined directly from the heat and mass balances of the fuel production plant (Section 5.1.4), the actual amount sold will be limited by nearby demand. For the rankings developed in this work, site specific limits to the by-product uptake were imposed using the methodology described in this section.

5.5.1 Heat

Heat is a local resource and although solutions for long distance transport of heat have been proposed, excess heat must realistically be used close to its source. This means that excess heat sales from e-fuel plants will be limited by nearby heat demand. The investigated fuel production plants have three main sources of excess heat: electrolysis, fuel synthesis and the carbon capture process. Since it was assumed that excess heat from fuel synthesis will be used to cover (part of) the heat demand for carbon capture (see Section 5.1.4), this heat cannot be sold.

In this work, annual heat deliveries from the investigated e-fuel plants were assumed to be limited by nearby district heating demand, which was estimated using *Halmstad University District Heating and Cooling Database (HUDHC)* , a database containing information on district heating and cooling networks in the Nordic region (publicly available via e.g. [38]) . Specifically, the database contains information on which areas have district heating networks and estimates of the annual residential and service sector heat demand of those areas. The area names given in HUDHC (city names or similar) were matched to the site location names given in the E-PRTR to determine which potential e-fuel production sites are in areas with district heating demand.

For e-fuel plants located in district heating areas, the maximum amount of heat that can be sold was assumed to be 25 % of the annual residential and service sector heat demand of the area. There are several reasons for using a number substantially lower than 100 %. Firstly, most of the excess heat is rejected from the electrolyser at low temperatures (<80 °C) meaning other heat sources will be required in the district heating network to guarantee that target temperatures are met. Secondly, it is reasonable to assume that the district heating companies want to maintain a certain degree of control of the production units in the network – i.e., to limit the dependence on excess heat from plants whose primary operating goal is different than maintaining district heating deliveries. Thirdly, experience says that industrial plants in general find it difficult to market excess heat, and even those that have contracts with district heating companies sell less than all available heat.

5.5.2 Oxygen

Production plants within several industrial branches (e.g. iron and steel, pulp and paper) use oxygen in their production processes. For large-scale plants, oxygen is often produced on-site but may also be imported. Within this project, oxygen deliveries from the e-fuel production plants were assumed to be limited by the oxygen demand of the co-located industrial sites. While oxygen may also be (compressed/liquefied and) exported to off-site users, this option carries an additional cost and – more importantly for the scope of this project – is less site-specific, i.e., it does not contribute to production cost differences between sites. A similar argument can be made for locating new industrial users (e.g. fish-farms) close to the e-fuel plant.

In this work, site specific oxygen demands were estimated using a case-study based approach where the relation between CO_2 emissions and O_2 demand was assumed constant for all plants within the same industrial branch. Using this approach, oxygen demand was estimated for one site in each industrial branch and scaled to the other sites by the CO_2 emission ratio.

Oxygen demand was primarily estimated using data from a 2017 report on industrial oxygen demand in Finland [39] which covers iron and steel, pulp (and paper), oil refining and certain branches of chemicals and non-ferrous metal production. Complementary data was obtained for some sites using e.g. company environmental reports and similar. Assumed oxygen demands are summarised in Table 5.9. and a more detailed version of the table (including references and additional assumptions) is available in Appendix 9.3. Only those industrial branches where a significant oxygen demand was identified have been included in the table. Note that the oxygen demand of methanol production is heavily dependent on the production pathway. The number given in the table applies to production using autothermal reforming, which is the pathway used at the only methanol plant included in this work. For methanol production using e.g. steam reforming, there is no oxygen demand.

For comparison, the fuel production process generates around 1000-1500 tonnes O_2 per ktonne CO_2 input (depending on the produced fuel, see mass and energy balances in Section 5.1.4). This means that – if *all* CO_2 emissions are utilised for fuel production – only sites with an oxygen demand higher than this number can export all the produced oxygen.

Table 5.9. Estimated oxygen demand in relation to reported CO_2 emissions for industrial activities considered in this work. The table includes only activities for which significant oxygen demand has been identified.

Industrial activity	tonne O_2/ktonne CO_2 emitted
Pulp (and paper)	11
Integrated iron and steel mills (blast furnace process)	90
Secondary steel production (electric arc furnace process)	160
Copper production	1480
Ferromanganese production	70
Steel processing	350
Oxo-synthesis	1060
Methanol production	1160
VCM production	350

5.6 Power market model, electricity price levels and network capacity

5.6.1 TheMA fundamental power market model

To analyze future power prices, we use THEMA's in-house power market model, TheMA. TheMA is a fundamental power market model that covers Europe and the Nordics. This tool allows the forecasting of future price developments by simulating power market dynamics. This essentially means that the model tries to meet demand at the least possible system cost. The price for each hour is determined by the marginal cost of the marginal plant that must be dispatched to meet demand. To solve the cost minimization problem, the model uses linear programming (LP) techniques to find an optimal solution. Equivalently, a fundamental market model can be considered as a welfare maximization problem under a set of constraints. The constraints include static constraints (for example plant availabilities) and inter-temporal constraints (e.g. start-up optimisation constraints).

For this analysis, we use the results of THEMA's Best Guess and Emissions Eliminated scenarios from February 2020 [40]. The results in each scenario describe the power prices and the energy mix if a certain path towards decarbonization is pursued. In the Best Guess scenario, it is assumed that the EU 2030 targets are fulfilled and the power sector is decarbonized by 2050. It is also assumed that electricity demand will increase due to sector coupling and that the EU ETS emissions cap will be tightened. The Emissions Eliminated scenario is more climate-friendly and considers a world in which the Paris Agreement is fulfilled and carbon neutrality achieved by 2050 even beyond the power sector. This entails a phase-out of coal-fired power plants by 2040 and no use of natural gas after 2050. Power demand growth is expected to be higher due to increased electrification and increased production of hydrogen and synthetic fuels for the decarbonization of the heating and transport sectors.

Modelling Power-to-Hydrogen in the TheMA Model

Within the TheMA model, we model a market for power-to-hydrogen. Based on a set of assumptions for the demand and cost of hydrogen, the model optimizes investment in hydrogen production sites to cover demand, the production of hydrogen from electricity, power generation from hydrogen (X2P) and the trade of hydrogen between zones and from other sources.

Aggregate demand for hydrogen (excluding gas-to-power demand) was defined as an input to the model based on the levels estimated in the two 1.5-degree scenarios developed by the European Commission in 2018 [41]. Aggregate EU-wide hydrogen demand was distributed across countries and price zones according to these zones' energy use and political ambition for the deployment of hydrogen. To allow the model to endogenously invest in electrolysis capacity to meet the demand for hydrogen, electrolysis costs were specified based on assumptions taken from the IEA [42]. The model then determines the best locations for electrolysis facilities with a cost-optimal capacity and utilization factor. In addition, the TheMA model computes the trade of hydrogen between price zones, within constraints of assumed infrastructure availability, and the use of hydrogen from external sources such as imports from outside Europe or blue hydrogen produced from natural gas. All power-to-hydrogen production parameters are co-optimized with power dispatch on an hourly basis.

5.6.2 Model results

After modeling the power market under the assumptions described above, the power prices from 2025-2045 are determined for both scenarios and shown in the Appendix in Table 9.5. As an example, power prices in the Best Guess Scenario in 2035 are illustrated in Figure 5.1. Power prices are higher in the Emissions Eliminated scenario due to the higher carbon prices needed to reduce GHG emissions and as a result of the higher electricity demand needed to decarbonize other sectors. The lowest future power market prices are likely to be found in Iceland and in the Norwegian bidding zones, particularly in Northern Norway (NO4 and NO3).

Note that Iceland was not modeled using the TheMA model. The power price estimates for Iceland are based on expected PPA prices, while the renewable energy generation shares are based on installed capacity. The reason for this is that the Icelandic power system is isolated from international markets and all power is sold through PPAs. Generally, under this setup, the generation company (mostly Landsvirkjun) owns a portfolio of assets and enters into agreements with large industrial users and retail companies to sell electricity at a certain price. Because of this, these PPA prices are the effective market price in the country and mostly represent the LCOE of the generation company's asset portfolio (mainly hydropower and geothermal in Iceland's case). Our price estimates for Iceland, therefore, are based on the combined LCOE of these technologies. By using the average LCOE of projects in [43] and in [44], we obtain an estimate on the typical costs in the country. To align with the modeled scenarios used for the other Nordic regions, PPA prices in Iceland are higher in the Emissions Eliminated scenario, where we assume that Iceland becomes interconnected with the United Kingdom. Based on the effect international interconnectors have, the price levels increase by about 2 EUR/MWh in 2035 and 0.5 EUR/MWh in 2045 compared to the Best Guess Scenario.

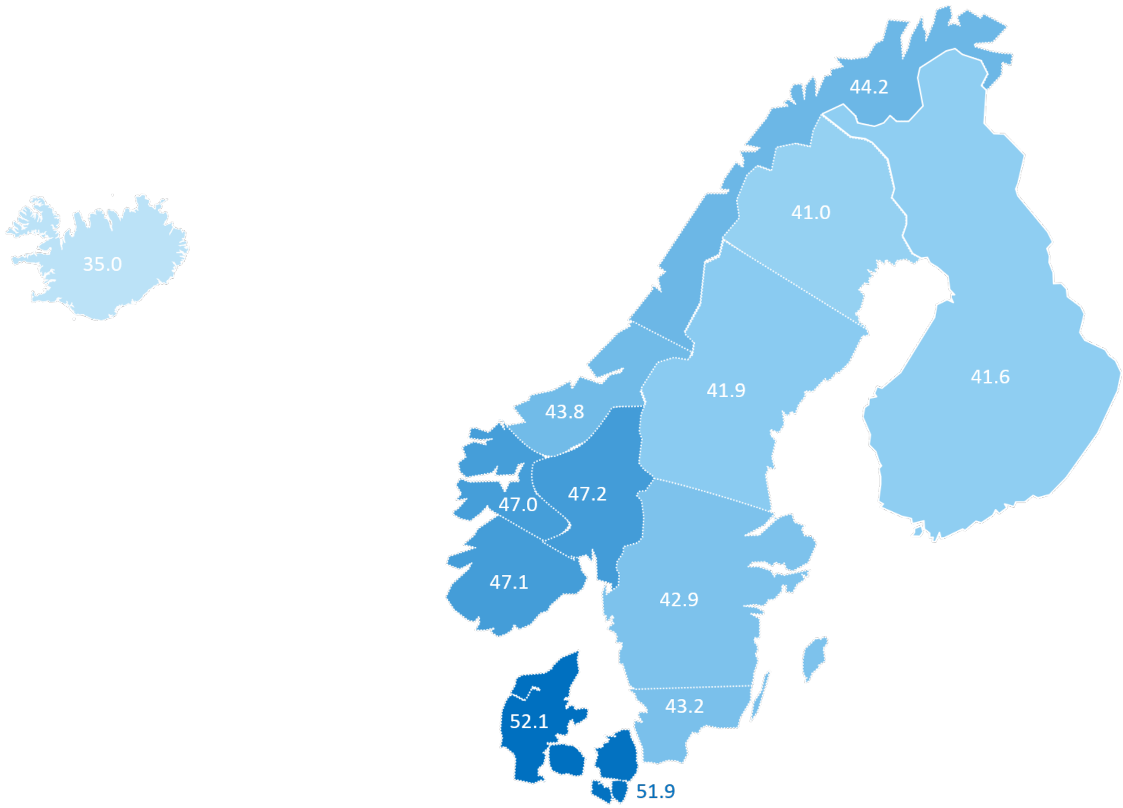

Figure 5.1: Power price in EUR/MWh in 2035 based on TheMA model results

The share of renewable energy in the generation mix increases under both scenarios. By 2045, most of the bidding zones start reaching a very high share of renewable generation (nearing 100%) and the gaps between low- and high-renewable generation regions close. For most bidding zones (notably in Norway, Sweden and Iceland), the renewable share is already quite high in 2025 and therefore no big changes in the renewable share are observed during the modelling period. For others, such as Denmark and Finland, an increase can be observed between 2025-2045 as the climate goals outlined in the scenarios are met. The resulting shares for each scenario can be observed in Table 9.6

5.6.3 Relevant electricity cost for P2X production

Our approach to the estimation of electricity costs has been significantly influenced by assumptions about the operating behavior of P2X production facilities. In particular, we assume that operators will wish to realize the highest possible utilization of their electrolysis capacity, given the high capital costs associated with this capacity, effectively choosing to run this capacity as much as is practically possible. We also assume that they will seek to ensure that a significant share of their production qualifies as renewable under the recast Renewable Energy Directive.

The detailed regulation establishing e-fuels' eligibility for classification as a renewable transport fuel has yet to be drafted. Consequently, we have had to make some assumptions as to what sort of operational setup would produce renewable e-fuels based on the text of the recast Renewable Energy Directive. Box 1 below reproduces key elements of the relevant legal text.

Box 1. Excerpts from the Recast Renewable Energy Directive

Recital 59:

> *"Guarantees of origin which are currently in place for renewable electricity should be extended to cover renewable gas."*

Recital 90:

> *"To ensure that renewable fuels of non-biological origin contribute to greenhouse gas reduction, the electricity used for the fuel production should be of renewable origin. The Commission should develop, by means of delegated acts, a reliable Union methodology to be applied where such electricity is taken from the grid. That methodology should ensure that there is a **temporal and geographical correlation** between the electricity production unit with which the producer has a bilateral renewables power purchase agreement and the fuel production. For example, **renewable fuels of non-biological origin cannot be counted as fully renewable if they are produced when the contracted renewable generation unit is not generating electricity**. Another example is the case of electricity grid congestion, where **fuels can be counted as fully renewable only when both the electricity generation and the fuel production plants are located on the same side in respect of the congestion**. Furthermore, there should be an **element of additionality**, meaning that the fuel producer is adding to the renewable deployment or to the financing of renewable energy." [Emphasis added]*

Article 25.2:

> *"The greenhouse gas emissions savings from the use of renewable liquid and gaseous transport fuels of non- biological origin shall be at least 70 % from 1 January 2021."*

Article 27.3:

> *""where electricity is used for the production of renewable liquid and gaseous*

transport fuels of non-biological origin, either directly or for the production of intermediate products, the average share of electricity from renewable sources in the country of production, as measured two years before the year in question, shall be used to determine the share of renewable energy.

However, electricity obtained from direct connection to an installation generating renewable electricity may be fully counted as renewable electricity where it is used for the production of renewable liquid and gaseous transport fuels of non-biological origin, provided that the installation:

(a) comes into operation after, or at the same time as, the installation producing the renewable liquid and gaseous transport fuels of non-biological origin; and

(b) is not connected to the grid or is connected to the grid but evidence can be provided that the electricity concerned has been supplied without taking electricity from the grid.

Electricity that has been taken from the grid may be counted as fully renewable provided that it is produced exclusively from renewable sources and the renewable properties and other appropriate criteria have been demonstrated, ensuring that the renewable properties of that electricity are claimed only once and only in one end-use sector.

By 31 December 2021, the Commission shall adopt a delegated act in accordance with Article 35 to supplement this Directive by establishing a Union methodology setting out detailed rules […]"

On the basis of this text, we conclude that:

- "Grid electricity may be counted as fully renewable" provided that appropriate criteria have been demonstrated. Specifically, we assume that if a P2X producer buys power, and possibly Guarantees of Origin, through a Power Purchase Agreement (PPA) from a new onshore windfarm within the same bidding zone, any e-fuel produced with this power will be fully renewable. The signing of a PPA with new renewable generation assets, possibly combined with the associated cancellation of any associated Guarantees of Origin, is expected to provide a sufficiently robust link to be able to demonstrate the simultaneity of generation and consumption and the additionality of generation as required by recital 90. Similarly, the requirement that the generation asset be within the same bidding zone is considered sufficient to demonstrate that the power is not behind a transmission congestion, as also required by recital 90.

- Where e-fuels are produced using grid electricity and no further criteria are demonstrated in relation to the power's source, "the average share of electricity from renewable sources in the country of production, as measured two years before the year in question, shall be used to determine the share of renewable energy". As such, a share of the e-fuel produced using this power may still be renewable.

We have assumed, therefore, that P2X producers seek to source their electricity from new onshore wind capacity within the same bidding zone using a PPA, but that they will supplement this power supply with general grid electricity where wind output from the linked assets is insufficient to run the electrolysis capacity at full-load. The PPA may also cover Guarantees of Origin so as to enable the P2X producer to certify the source of the renewable power acquired via the PPA. Given this setup, in which some grid power is used, the e-fuel produced will, in general, be primarily, but not 100%, renewable in origin.

We have considered that, in practice, P2X producers may choose to restrict production during periods of high-power prices. However, we have concluded that, given the observed volatility of prices, accounting for this additional complexity was unlikely to materially affect the relative competitiveness of P2X production sites. As such, we have not accounted for the presence of a cut-off price for power.

The share of power sourced from new wind assets, instead of general grid supplies, is a commercial decision taken by the P2X producer and would ultimately depend on the additional value associated with gaining renewable accreditation for the e-fuel output. Since we have little basis on which to estimate this additional value, we have made the simplifying assumption that the PPAs used to source the P2X production facilities' power needs cover a portfolio of wind assets in the same bidding zone such that the median output of the associated wind assets is equal to the full-load demand of the P2X producer's electrolysis capacity (See Figure 5.2). As such, in half of all hours, the P2X producer's electricity demand can be fully supplied by the associated wind assets. In the other half, at least some demand is met by grid electricity. An obligation to supply power equal to the median output of the assets is referred to as a P50 obligation.

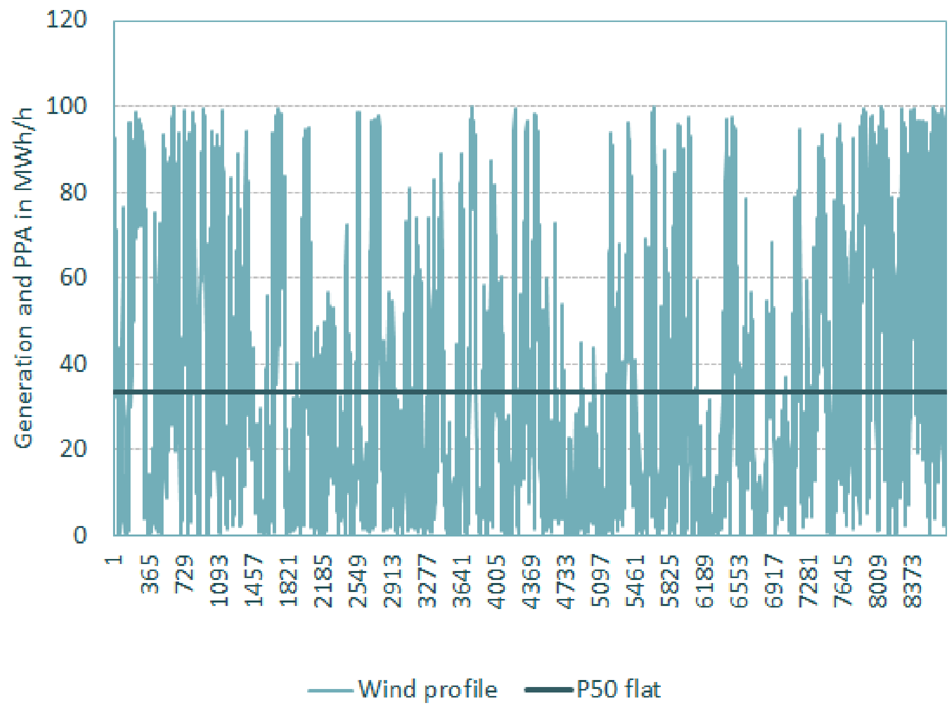

Figure 5.2 Illustration of a P50 obligation for a power producer, in which half of the produced volume is above the P50 line and the other half below.

As can be seen in Figure 5.2, the wind asset will not be able to satisfy the obligation during some hours and will have to purchase energy from the grid to do so, resulting in so-called sleeving costs. Likewise, when the asset produces more than the obligation, it can sell the extra power to the grid. This entails both costs and revenues that need to be accounted for to offer a price in a PPA agreement. To completely capture the costs experienced by the asset owner, the PPA price is determined by considering the operating costs and the expected cash flows from buying and selling energy from/to the grid (see below). Where required to ensure that the e-fuel produced can be classified as renewable, we assume that the PPA covers the provision of the Guarantees of Origin associated directly with the wind output used by the P2X producer. No Guarantees of Origins are assumed to be purchased to cover any grid power used.

$$PPA\ Price = LCOE\ (EUR/MWh) + \frac{Sleeving\ Costs - Revenues\ (EUR)}{Energy\ (MWh)}$$

$$Sleeving\ costs = \sum_{i=0}^{N} Power\ Price_{i}(EUR/MWh) \times (P50\ Obligation\ (MWh) - Generation_i(MWh))$$

$$Selling\ Revenues = \sum_{j=0}^{M} Power\ Price_{\ j}(EUR/MWh) \times \left(Generation_j\ (MWh)\ -\ P50\ Obligation\ (MWh)\right)$$

Where i represents the hours in which the obligation was higher than the generation from the asset and j represents the hours in which the generation was higher than the obligation

The LCOE, power prices, and maximum energy yield for a wind asset differs in each zone, and therefore the offered PPA prices are different for each area, favouring those zones with high wind energy yields and lower power price levels. Interestingly, a trend can be observed between power prices and wind in-feed. Since low prices are almost always correlated with higher volumes of wind production, the selling price is typically lower than the buying price (when purchasing or selling from/to the grid). However, in some instances, this might not be the case (e.g. when penetration of wind is low). However, in the future, as more wind energy enters the mix, the energy production from variable renewable sources becomes increasingly correlated with power prices, resulting in higher sleeving costs and negative cash flows associated with the use of grid power.

Due to technological improvements and economies of scale, the LCOE of wind assets is expected to decrease over time, countering the effect of increasing sleeving costs. Zones with lower price levels, such as NO3 and NO4, offer the most attractive PPA agreements, which is to be expected as lower power prices allow for lower sleeving costs. Figure 5.3 illustrates the PPA prices for Nordic price zones in the Best Guess Scenario in 2035. All results for PPA prices in both Best Guess and Emissions Eliminated are summarised in 5.3.

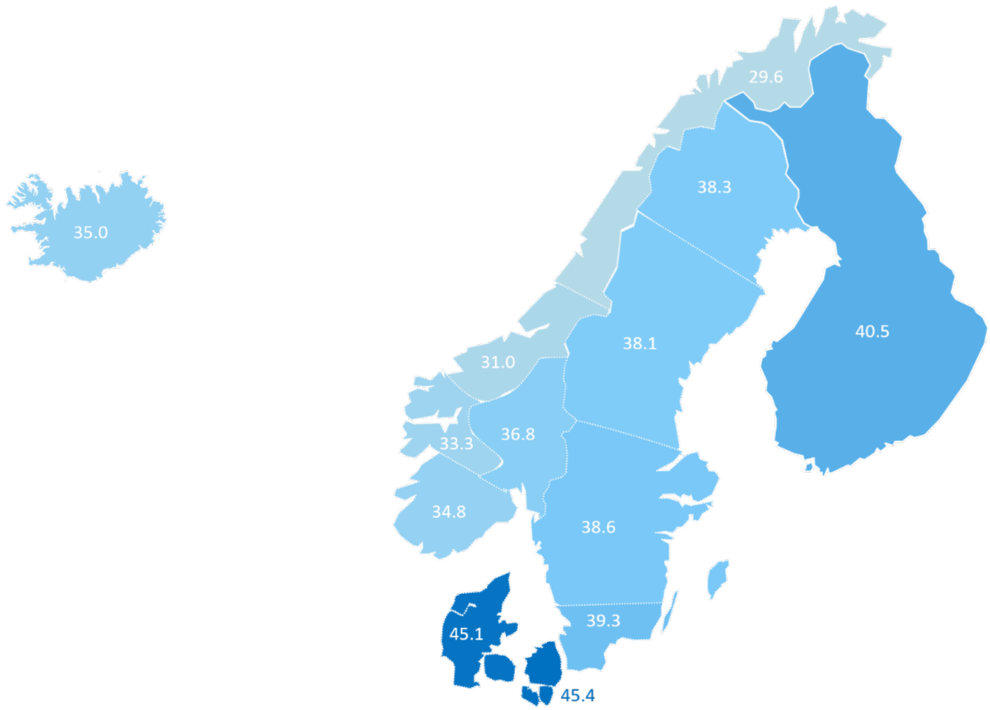

Figure 5.3: PPA prices in EUR/MWh in the Best Guess Scenario in 2035

To effectively calculate the degree of renewable energy used to produce a specific e-fuel, it was necessary to determine the share of electricity purchased from the grid that itself had a renewable origin. To do this, we have used "the average share of electricity from renewable sources in the country of production, as measured two years before the year in question", consistent with the drafting of the recast Renewable Electricity Directive. The total RES shares shown below, reflect the share of renewable energy in all of the power consumed by the P2X producer (i.e. considering both the volumes acquired directly from a wind assets through the PPA, which are 100% renewable, and the volume of RES acquired through the grid power). Figure 5.4 illustrates the results share of RES from purchased power in the Best Guess Scenario in 2035. The detailed numbers for all zones, years and scenarios are shown in 5.4. While differences in RES shares are still visible in 2035, the resultant e-fuel production is almost 100% renewable for most zones by the end of the modelling period.

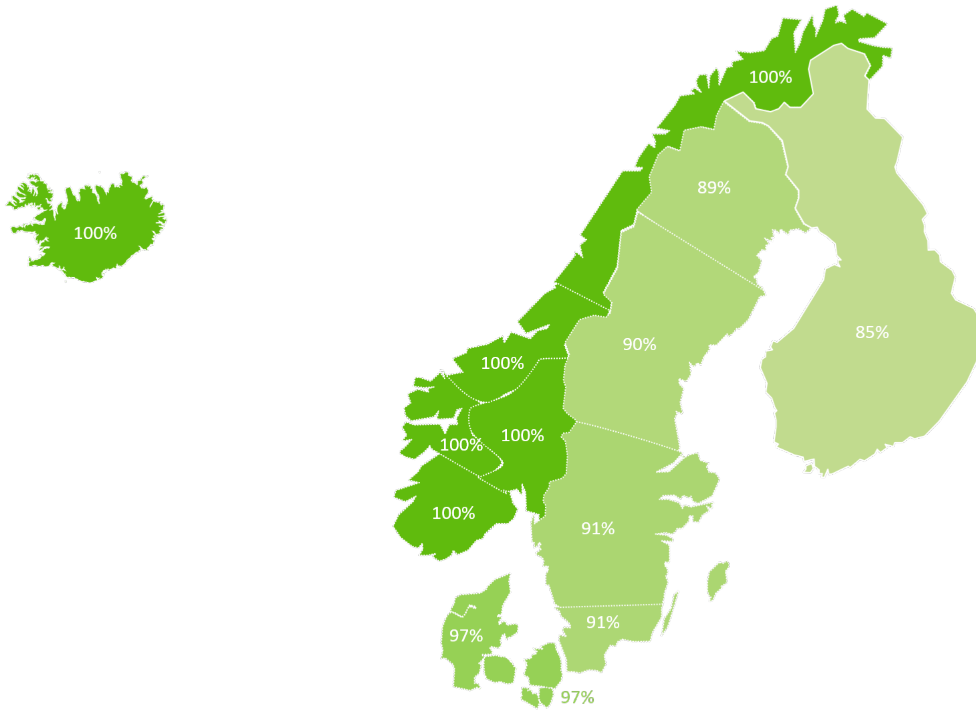

Figure 5.4: Share of RES from PPA agreeement in the Best Guess Scenario in 2035

We also calculated the carbon intensity of generation per zone (See Table 9.9). From these results, one can see that some regions, such as Denmark, experience a dramatic decrease in the carbon-intensity of generation. These are largely triggered by the shutdown of fossil fuel generation capacity to meet climate goals. By 2045, the emissions levels of most regions are very low compared to the initial levels from 2025. This is especially true in the Emissions Eliminated scenario, in which emissions fall faster to achieve emissions neutrality by 2050.

5.6.4 Network capacity

In addition to the cost of power, one also needs to consider whether sufficient network capacity is available to accommodate the increased demand for power resulting from e-fuel production. Although the power model does not contain sufficiently granular network data to answer this question definitively, it does nevertheless provide a useful indication of high-level congestion constraints within the Nordic power system.

If all power transfers in the system were happening on a copper plate with uniform conductivity, i.e. without any network limitations on transfer capacity, the power price in all zones would be the same. Location would cease to be a relevant factor. In reality, existing infrastructure and available network capacity constrains how much electricity can be transferred at any given time. Price differences occur between price zones precisely because network capacity is insufficient to allow low-cost power to displace high-cost power. A zone with a power surplus and limited export capacity will experience lower prices than a zone that relies on power imports over existing cross-zonal connections.

The input data for the TheMA model includes detailed information on cross-zonal transmission capacity and accounts for all planned extensions to such capacity. The resulting power prices, therefore, reflect the impact of present and future network constraints at bidding zone borders. As an example, Figure 5.1: Power price in EUR/MWh in 2035 based on TheMA model results shows the power prices in Nordic price zones in 2035 based on TheMA model results. It can be seen that power prices in Northern Sweden are the lowest, which reflects the fact that there is a large volume of wind power in SE1 and SE2 and limited transfer capacity to major centers of demand in the South.

Areas with lower prices, therefore, reflect zones in which there is a surplus of generation and insufficient network capacity to export this cheap power to neighboring zones. Adding additional demand to such low-price zones will, in general, help to reduce pressure on cross-zonal capacity by absorbing some of this excess supply, limiting the market pressure to export power. Adding additional demand in low power price zones should not, therefore, be constrained by limits to cross-zonal network capacity. This does not mean that additional network capacity may not be required within-zone and, indeed, the large absolute scale of these facilities as considered in the cost estimates suggests that some local network modifications will likely be needed to accommodate them. However, there is little basis on which to credibly estimate available grid capacity at a local level in the distant future and therefore differentiate between sites on this basis, as this will be heavily reliant on projections of local grid use.

5.7 Greenhouse gas reductions

The GHG emission reduction potential, so called "emissions saving" is evaluated according to RED II sustainability criteria for all fuel alternatives in relation to their corresponding fossil counterpart.

$$\text{Emission saving} = \frac{\text{emissions of fossil comparator - emissions of studied fuel}}{\text{emissions of fossil comparator}}$$

According to RED II, the GHG emissions are calculated for the whole life cycle of a fuel, including all the emission related to the inputs needed in the fuel production process. The functional unit of the analysis is one MJ of fuel, and the total life cycle emission of the studied fuel is compared to a corresponding life cycle emission of a fossil counterpart. Currently, for fuels used in transportation this fossil comparator is defined to be 94 gCO_2/MJ. The comparator for renewable liquid and gaseous transport fuels of non-biological origin is not yet defined, so the current value for transport fuels is used. The emission saving limit required from "renewable liquid and gaseous transport fuels of non-biological origin" is 70%.

For allocating emissions between the produced fuel and its potential co-products, RED II uses energy allocation. This is the case, even if the co-product is not used for energy purposes. In this study, GHG emissions are allocated to the co-product heat, according to the heat demand in the region. No emissions shall be allocated to the co-product heat if there is no demand for the heat in the region (e.g. district heating / industrial process needs). User can also choose to study results without allocation to heat, as the impact to the GHG emission saving result is significant. In the case of e-fuels studied here, energy allocation prevents allocating emissions to co-product oxygen, as oxygen does not have lower heating value (LHV). This can be considered problematic if the co-product oxygen is used and substitutes oxygen produced elsewhere.

For the emission of electricity used in the process, the RED II currently requires use of average emission of the region, if the production plant is connected to the grid (two-year lagged country averages). If the production facility gets renewable electricity directly from a production plant not connected to the grid, the emission intensity of the plant in question can be used. The rules for the definition of the emission intensity of electricity used for "renewable liquid and gaseous transport fuels of non-biological origin" is not yet defined, and there might be new ways to prove the use of renewable electricity. For e-fuel plants using the PPA set-up described in Section 5.6.3, the emission factor of electricity sourced from the renewable asset was taken to be zero meaning that the overall electricity emission factor for all electricity input was calculated as the grid average times the fraction of electricity input sourced from the grid. The used emission factors are summarized in Table 5.10.

The captured CO_2 used in the process is assumed to have zero emissions (Meaning that the emissions shall be counted in the facility where the CO_2 is captured). One needs to be careful to avoid double counting the benefits of CO_2 capture. Clear rules for defining the emission of CO_2 capture and use are needed in the Commission's delegated act on GHG calculation rules for e-fuels.

Table 5.10. Used emission factors for electricity (Best Guess scenario)

EMISSION FACTORS, electricity	2025	2035	2045	
Direct connection with renewable production	0	0	0	gCO_2/kWh
Norway, grid average	1,5	1,3	1,2	gCO_2/kWh
Sweden, grid average	21	17	18	gCO_2/kWh
Finland, grid average	80	43	43	gCO_2/kWh
Denmark, grid average	102	22	15	gCO_2/kWh
Iceland, grid average	0	0	0	gCO_2/kWh

Other process emissions are given in Table 5.11 and include the potential emissions of catalysts and chemicals used in the process. These emissions are included based on the study by Liu et al. [45], and represent a rough estimation on the scale of these type of emissions. In addition, the emission of transport and distribution of final fuel is included based on the default values presented in the current RED II for similar type of fuels from biomass origin.

Table 5.11. Emission factors for other process emissions

Other emissions		
Transport and distribution of final fuel	2,0	gCO_2/MJ_fuel
Chemicals and catalysts	0,1	gCO_2/MJ_fuel

5.8 Infrastructure

To support the ranking analysis based on infrastructural demands, data from literature, relating to different types of production sites and to different fuels are used. This section describes the data used and the resulting categorization. Ranking results are then presented in Section 6.3.

5.8.1 Production-related infrastructure

In this section the infrastructural conditions for different production sites linked to electrical network capacity, available water supply, industrial infrastructure for integration synergies, and the closeness to district heating systems are summarized and clarified, based on data and literature reviewed above. On the level of detail of this analysis, these conditions can be considered the same regardless of which fuel is produced. As noted before, these aspects are all included in the cost ranking above and a ranking of sites based on production-related infrastructure specifically, has therefore not been made.

Electrical network capacity. As noted in Section 5.6.4, all or most production sites for e-fuel are, due to the large amount of electric power needed, expected to need local network modifications and additions (within the same prize zone). At the same time all the sites linked to CO_2 point sources, which primarily are in focus of this study, are industrial sites with a relatively well-developed electrical infrastructure. The transmission capacities across different price zones are mirrored in the electricity price, so that lower priced zones have more well-developed electric infrastructure.

Available water supply. Data on water supply indicate that all sites have satisfactory access to water and that this is not an aspect that considerably distinguishes them in terms of their infrastructural situation. There may be other site specific water related infrastructure, such as availability of water treatment facilities. However, information at this level of detail is out of scope for this study.

Industrial infrastructure. Siting e-fuel production in connection with an existing industrial site provides an infrastructural advantage in itself. All specific sites included in this study are larger-scale industrial sites with basic industrial infrastructure. Thus, these have infrastructural advantages, compared to green-field sites that could be in question for, for instance, hydrogen production. Some types of industrial sites have additional advantages, such as industries with a high demand for the by-product oxygen in its processes (as e.g. the pulp and paper and iron and steel sectors) or with already built-up storage facilities (as refineries).

Closeness to district heating systems. Sites that are located close to larger cities with district heating systems (or other large heat sinks) have an infrastructural advantage since e-fuel production will generate a heat surplus, which can then be utilized. Fuel distribution infrastructure.

5.8.2 Fuel distribution-related infrastructure

Input data for categorization of fuel distribution-related infrastructure are based on the literature review below. The infrastructural demands are primarily described in relation to the various fuels produced, but also depend on where the production is located.

The cost of infrastructural demands, including distribution, storage and filling stations has been estimated as high, medium, minor or none by Kramer et al [1]. The costs are then put in relation to the infrastructural cost of conventional fossil diesel and gasoline use. According to Kramer et al, the costs for the fuels included in this study would be classified in the following way:

- Methanol and DME – minor
- Methane - medium
- FT-liquids – none
- Hydrogen - high

In Soler [10], positive and negative characteristics of different e-fuels are described in relation to their lower heating value, storability, additional infrastructure and need for powertrain development. In this overview, demand for additional infrastructure is identified for hydrogen, ammonia, DME and OME while no additional infrastructure demand is expected for methane, methanol, diesel, gasoline and jet-fuel.

In line with these references, the fuels included in this study have been sorted qualitatively, based on current infrastructural situation for fuel distribution to customers, on a gradual scale from high to low level of available infrastructure (see Table 5.12).

Table 5.12 Qualitative sorting of type of fuels included in the study, from currently high (green) to low (red) level of available fuel distribution infrastructure. Here, the sorting is related to the type of fuel only and the location of fuel production is not taken into account.

Fuel category	Fuels in study
Drop-in liquid fuels	Synthetic diesel and gasoline (FT-liquids)
New liquid (and semi-liquid) fuels	Methanol, DME
Gaseous fuels w infrastructure	Methane
Gaseous fuels wo infrastructure	Hydrogen

The infrastructural conditions for distribution of fuels over longer distances, from production sites to demand centers, are dependent on both type fuel and the location of the production site. Kramer et al [1] estimated the energy demands for longer distance distribution of different fuels, with fossil diesel as reference case. Also in this respect, the infrastructural cost for hydrogen is considerably higher than for other fuels, while additional infrastructural costs for FT-liquids can be considered negligible.

In the Nordic context, the situation for methane differs somewhat from the general picture, since natural gas distribution grids – in which also e-methane could be distributed - are only available in parts of the Nordics. Connected natural gas grids are available in Denmark and in the southern region of Sweden (including the most southern region of Skåne, and the Swedish west coast). In addition, a limited natural gas grid covers the southern and south-eastern parts of Finland. In Norway, there are natural gas production, some industrial gas use along the Norwegian coast and transmission lines to Germany, Belgium, France and the UK, but no distribution grid in Norway. Therefore, the gas infrastructure in Norway benefits methane production in Norway, but not for the Nordic road transport market, which is in focus of this study. In addition to these natural gas grids there are local biomethane grids in several areas.[21]

In addition to these fuel related aspects, the main infrastructural aspect that is directly dependent on the location of the fuel production site is the availability of a harbor. A harbor facilitates standard transportation solutions for all liquid fuels and for methane as LNG. The other aspect that should be taken into account is the proximity between the production site and larger fuel demand centers, consisting of more densely populated areas.

Based on these references and principle observations, four different types of regions for fuel production sites with differing infrastructural conditions for fuel distribution have been defined (see also Figure 5.5):

- Remote locations without harbour (1) – This region includes primarily the northern inland areas in Sweden and Finland. It could also include Norwegian mountain areas and the Icelandic inland. Those areas, however, lack industrial CO_2 source sites.
- Central locations without harbour (2) – This type of region differ from the former, in terms of the size of the regional fuel market and of available road and rail transportation infrastructure. The region consists primarily of inland areas in southern Norway, Sweden and Finland.

[21] https://www.norskpetroleum.no/en/production-and-exports/the-oil-and-gas-pipeline-system/

- Location with a harbour (3) – All production sites that have nearby access to a sea harbour can be considered equal from a fuel distribution point-of-view regardless of their remoteness to Nordic fuel demand centers.
- Region with distributed NG grid (+NG) – In addition to the other aspects determining region, the availability of a distributed natural gas grid connected to methane fuel stations impacts specifically the conditions for distribution of e-methane. In the Nordics, such grids are available primarily in Denmark and southwest of Sweden, and to some extent in southeast of Finland. Regions with larger-scale distribution grids for bio-methane (not included in the map, below) could also have an advantage in this respect.

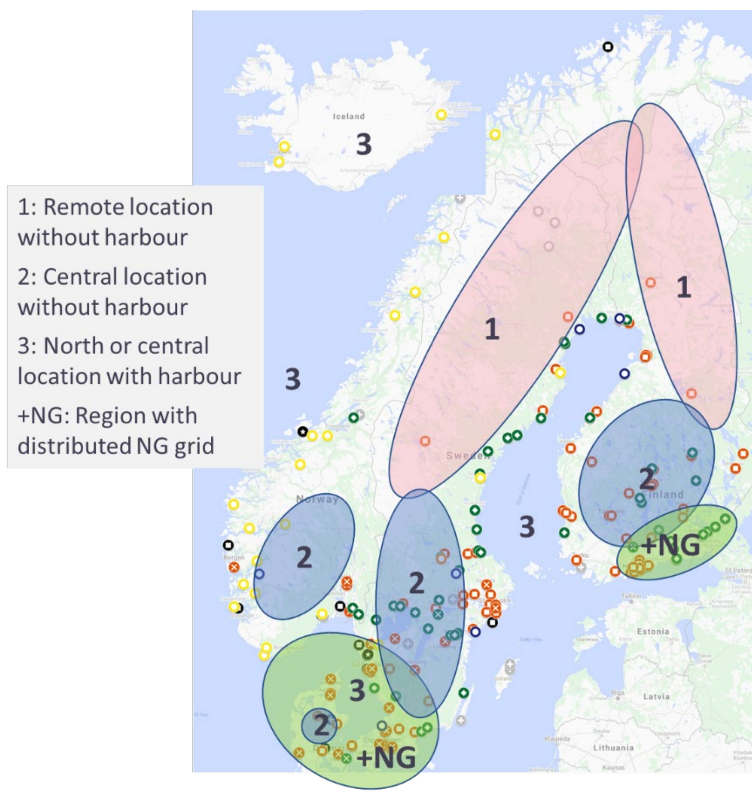

Figure 5.5 Principle illustration of the geographic expansion in the Nordics of the four types of regions described above.

6 Ranking results

In the present chapter the main results from the ranking of e-fuel production sites is presented, as well as the effect of changes to major input parameters and assumptions on the results discussed.

6.1 Ranking based on fuel production cost

Final cost rankings vary depending on fuel (affecting the relative importance of CAPEX and OPEX) and year (affecting power prices, electrolyser efficiency and electrolyser CAPEX). For carbon containing fuels, site rankings are very similar and a unified site ranking accounting for all carbon containing fuels and operating years was developed. First, average production costs for the three investigated years (2025, 2035, 2045) were calculated for each fuel and used to develop fuel specific site rankings. A unified ranking for carbon containing fuels was then developed based on the average site rank for the different fuels and is presented in Table 6.1, including the 15 best sites according to the unified ranking. For each of these sites, the table also gives the cost ranking for each investigated fuel. The production cost rankings for hydrogen are presented in Table 6.2. Complete rankings for each fuel can be obtained via the project database[22]. Note that the rankings in this report are based on the PPA set-up for electricity supply and the TheMA Best Guess scenario (see Section 5.6.1). Results for grid electricity prices and/or the Emissions Eliminated scenario can be obtained via the project database.

Cost-differences between best and worst-case locations are mainly related to differences in electricity cost, size of the plant (economy of scale) and potential by-product revenues. The importance of low electricity costs is the main reason why all the best 15 sites are in Sweden or Norway, and especially the Norwegian sites benefit from low electricity prices. The best identified site (Equinor's methanol production plant at Tjeldbergodden, Norway) combines low electricity prices with a high oxygen demand – allowing the e-fuel plant to sell all produced oxygen – and economy of scale benefits due to CO_2 emissions that are enough to accommodate the maximum plant size (200 MW_{el} electrolyser) assumed in this work.

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[22] A database used as basis for the calculations within the present project is publicly available at: www.nordicenergy.org/project/np2x/

The remaining Norwegian sites in Table 6.1 achieve low production costs mainly because of low electricity prices, while the Swedish sites at the top of the ranking also benefit significantly from by-product revenue and to some extent from economy of scale (all Swedish sites in the top 15 list can accommodate the maximum e-fuel plant size). Specifically, e-fuel production plants co-located with iron & steel mills or the Swedish copper-production plant (Rönnskärsverken) can export significant amounts of oxygen, and for Rönnskärsverken and SSAB Luleå the entire oxygen production can be exported. Similarly, the large district heating demand of the Swedish city Gothenburg means that e-fuel plants co-located with any of the city's two refineries (Preem and St1) have the potential to export all excess heat. The potential for heat exports also explains the presence of five waste incineration plants among the 15 best sites, as waste incineration plants are typically located close to district heating areas.

The best ranking sites for carbon-containing fuel production can produce roughly 10-11.5 TWh of e-fuel annually, the exact number depending on e-fuel and operating year. This is in line with the base case scenario for e-fuel demand in 2045 at 12.8 TWh/year (Table 3.2). Note however that the production volume at most of the 15 sites is constrained by the assumed maximum electrolyser size (200 MW_{el}), and that significantly larger volumes can be produced if all CO_2 available at those sites is utilized.

The ranking of hydrogen production sites (Table 6.2) differs to some extent from the ranking of carbon containing fuels. For hydrogen production, the amount of by-product per MWh fuel is lower. Since the conversion loss from hydrogen to carbon containing fuel is avoided, less hydrogen must be produced per MWh of final fuel product, meaning less by-product (heat and oxygen) from the electrolysis process per MWh fuel product. This is especially true for heat exports since excess heat from carbon capture is lost as well. Consequently, opportunities for by-product revenue are not as important for hydrogen, which further increases the importance of low power costs – although this effect is partly countered by the fact that less electricity is needed. Therefore, the hydrogen ranking contains only sites in Norway (13 out of 15 sites) and northern Sweden – while Swedish sites with large potential for heat exports (refineries and waste incineration plants, see Table 6.1) which perform well in the ranking of carbon containing fuels – are not among the best sites for hydrogen production.

Under the electrolyser size constraint used in this work (200 MW_{el}), roughly 15 TWh/year hydrogen can be produced at the 15 best sites (the exact number depending on the assumed operating year, affecting the electrolyser efficiency). This number exceeds e-fuel demand in the base case scenario for 2045 (12.8 TWh, Table 3.2). Of course, larger volumes can be produced if larger electrolysers are used.

To illustrate the factors that drive total production costs and the difference between sites with low and high production costs, Figure 6.1 compares methanol production in 2035 for the two best performing sites (the Equinor Methanol plant and the SSAB Luleå steel mill) to two of the most expensive production sites (Leca's clay aggregate plant in Randers, Denmark and LKAB Svappavaara's iron ore treatment facility in northern Sweden).

The importance of power costs is evident and accounts for 50-70 % of total production costs for the four sites. In general, differences in power costs also explain a significant share of the difference between the most and least expensive production sites. This is exemplified by a comparison between Leca Randers and Equinor Tjeldbergodden. The total difference in production cost is 34 EUR/MWh, of which 26 EUR/MWh can be attributed to power costs. The importance of by-product utilisation is also evident and despite a potential for heat exports from the Leca Randers site, the high potential for oxygen sales at the Equinor site gives a 5.4 EUR/MWh difference in by-product revenue for the two sites. On the other hand, carbon capture is expected to be cheaper at the Leca site due to higher CO_2 concentration, giving a 4.5 EUR/MWh benefit over the Equinor site (adjusted for size difference). The remaining cost difference (7.0 EUR/MWh) can be attributed to economy of scale effects – Leca Randers is one of the smallest included sites while the Equinor site can host an e-fuel plant at the maximum plant size.

Given the importance of power costs in the previous comparison, it is interesting to note that the sites LKAB Svappavaara and SSAB Luleå show a similar difference in production costs (29.1 EUR/MWh) despite being located in the same power price area. E-fuel plants located at the SSAB site can export the entire oxygen production and some heat, while only small amounts of heat can be exported from the LKAB site. This gives a total difference in by product revenue of 16.0 EUR/MWh (mainly due to oxygen exports). Remaining differences are due to economy of scale (7.9 EUR/MWh) and carbon capture costs (5.2 EUR/MWh, corrected for economy of scale). Once again, the LKAB site is one of the smallest included sites while the SSAB sites can easily accommodate the largest e-fuel plant size considered in this study.

As indicated above, the site rankings for different carbon containing fuels are very similar and the general conclusions drawn for methanol in the analysis above also holds for the other three carbon containing fuels. For hydrogen, the importance of power costs is even higher while by-product revenues are less important. Of course, differences in CO_2 concentration are not relevant and since the same plant size is evaluated at all locations, economy of scale has no impact on the hydrogen ranking.

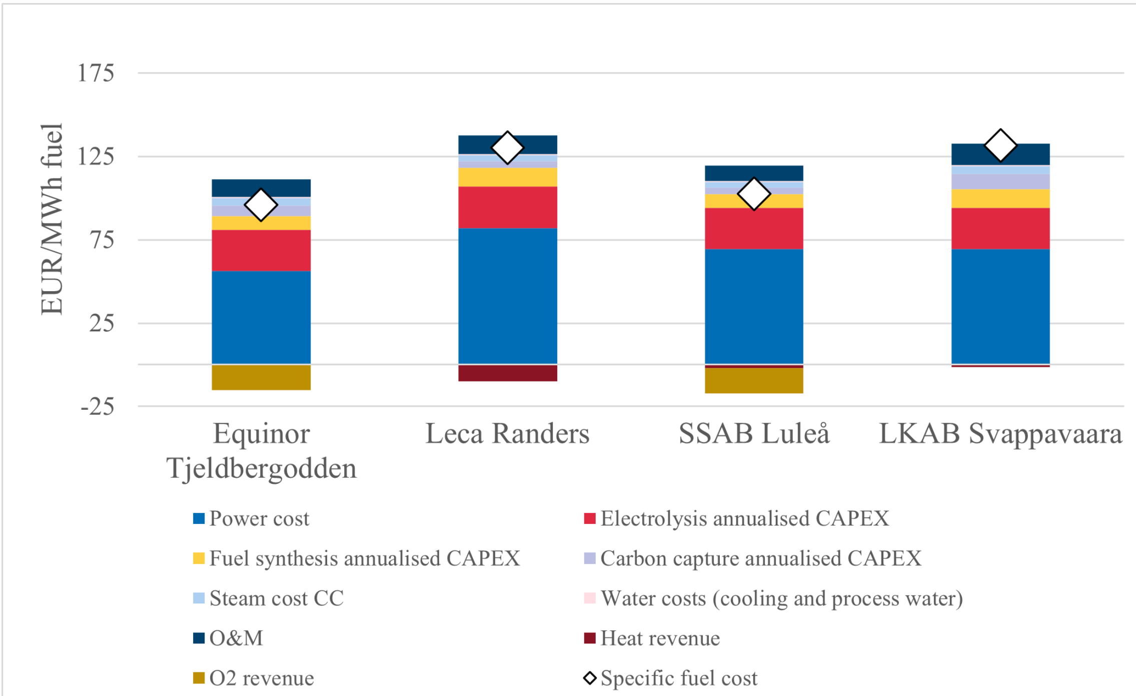

Figure 6.1. Production cost breakdown for two high-cost and two low-cost production sites

Table 6.1. The 15 best sites for carbon-based e-fuel production, ranked by fuel production cost. The table is sorted by average rank for the four investigated carbon-based e-fuels and the rankings for each fuel are given in columns 4-7.

Site	Branch	Price area	MeOH rank	DME rank	CH_4 rank	FT-liquids rank
Equinor Tjeldbergodden	Chemicals (Methanol)	NO3	1	1	1	1
SSAB EMEA AB i Luleå	Iron and steel	SE1	2	2	2	2
Fortum Oslo Varme	Waste incineration	NO1	3	3	3	3
Norcem Kjøpsvik	Minerals industry (cement)	NO4	4	4	5	4

Elkem Rana AS	Non-ferrous metals (FeSi)	NO4	7	7	8	6
HÖGDALENVERKET	Waste incineration	SE3	5	5	11	8
Sävenäsverket	Waste incineration	SE3	5	5	11	8
Rönnskärsverken	Non-ferrous metals (Cu (Pb, Zn))	SE1	9	9	6	5
Finnfjord	Non-ferrous metals (FeSi)	NO4	8	8	8	6
Hammerfest LNG	Natural gas processing	NO4	12	13	10	10
St1 Refinery AB	Oil and gas refining	SE3	10	10	14	11
Preem AB Preemraff Göteborg	Oil and gas refining	SE3	10	10	14	11
Ferroglobe Mangan Norge AS	Non-ferrous metals (FeMn)	NO4	14	14	7	14
Haraldrud energigjenvinningsanlegg	Waste incineration	NO1	15	15	4	16
Sysavs avfallsförbränningsanläggning	Waste incineration	SE4	13	12	16	13

Table 6.2 The 15 best sites for hydrogen production, ranked by fuel production cost.

Site	**Branch**	**Price area**	**H_2 rank**
Equinor Tjeldbergodden	Chemicals (Methanol)	NO3	1
SSAB EMEA AB i Luleå	Iron and steel	SE1	2
Rönnskärsverken	Non-ferrous metals (Cu (Pb, Zn))	SE1	3
NORETYL AS	Chemicals (olefins and	NO2	4

	VCM)		
Ferroglobe Mangan Norge AS	Non-ferrous metals (FeMn)	NO4	5
Alcoa Mosjøen	Non-ferrous metals (Al)	NO4	6
Norcem Kjøpsvik	Minerals industry (cement)	NO4	7
Elkem Rana AS	Non-ferrous metals (FeSi)	NO4	7
Elkem Salten	Non-ferrous metals (Si)	NO4	7
Finnfjord	Non-ferrous metals (FeSi)	NO4	7
Hammerfest LNG	Natural gas processing	NO4	7
Fortum Oslo Varme	Waste incineration	NO1	12
Haraldrud energigjenvinningsanlegg	Waste inceneration	NO1	12
Hydro Aluminium, Sunndal	Non-ferrous metals (Al)	NO3	14
NorFraKalk	Minerals industry (lime)	NO3	15
Norske Skog Skogn	Pulp and paper industry	NO3	15

6.1.1 Sensitivity to price levels and technology choices

This section discusses the impact that some important technology choices (electrolyser technology, direct air capture for CO_2 supply) and price levels (electricity input and by-products) have on the rankings given in Table 6.1 and Table 6.2.

Solid Oxide Electrolyser Cells (SOEC)

Given the importance of electricity prices, it is relevant to discuss the effect of increasing electrolyser efficiency, which would lead to decreased electricity consumption. By using the high temperature technology SOEC rather than alkaline electrolysis, the power-to-hydrogen efficiency can be increased to around 80 %. However, the amount of excess heat suitable for export will decrease. [32]

An analysis indicates that using solid-oxide electrolyser cells at 80 % efficiency would not significantly decrease the importance of power costs. For hydrogen production, there would be only minor differences in the site ranking and for carbon containing fuels, the sites in northern Sweden and Norway would still be at the top of the list. However, sites which benefit from high heat exports in the base case (oil and gas refineries, waste incineration plants), would now be less competitive and all sites in price region SE3 and SE4 (southern Sweden) would be replaced by additional Norwegian sites with lower power costs.

To conclude, the use of SOEC seems to increase the importance of low power costs, at least for carbon containing fuels. This is because the amount of excess heat is lower, which decreases the importance of high potential for heat exports.

Direct air capture

If CO_2 were captured directly from the air rather than from point sources, all sites would use the same CO_2 source and differences relating to the concentration of the CO_2 source would be cancelled. However – as was indicated in the above discussion relating to Table 6.1 and Figure 6.1 – CO_2 capture costs are not a major contributor to cost differences between sites and that the overall ranking for a case using direct air capture would be very similar to that given in Table 6.1. However, direct air capture technologies are significantly more expensive and total production costs would increase.

Electricity price scenario *Emissions Eliminated*

In the alternative price scenario – Emissions eliminated – of the TheMA power market model, electricity prices are higher and differences between market regions increase. In this scenario, location in a low power price region is even more important and the sites in southern Sweden (price regions SE3, SE4) are less competitive compared to the sites in northern Sweden and Norway. However, all sites in southern Sweden that are among the fifteen best sites in the base case for carbon containing fuels, would still be among the 20 best sites under electricity price scenario *Emissions Eliminated*.

For production of hydrogen, where low power prices are already more decisive in the base case, the choice of electricity price scenario has only minor implications for the cost ranking.

Higher by-product prices

By-products have a significant impact on the ranking. If higher by-product prices were assumed (for example, a 50 % increase), the three best performing sites for carbon fuel production – which already have significant by-product revenues – would keep their position. However, Norwegian sites in metals and minerals industry (see Table 6.1) have comparatively small by-product potential and would end up at the bottom or just outside of the fifteen best ranking sites. Instead, Swedish copper producer Rönnskärsverken (with high oxygen sales potential) and the refineries and waste incineration plants in Table 6.1 (with high heat export potential) would advance towards the top of the ranking. Under this scenario, Finnish steel producer SSAB Raahe would also be one of the fifteen best sites, due to high potential for oxygen sales.

For hydrogen production, the trend is the same and some of the Norwegian sites with low by-product potential towards the end of Table 6.2 would be replaced by sites in southern Sweden with high potential for heat exports, making the final ranking similar to the base case for carbon containing fuels (i.e., Table 6.1).

No by-product revenue

If no by-products were sold, power prices would have a huge influence on the ranking, for carbon containing fuels as well as for hydrogen production. For hydrogen production, the ranking would be strictly by power price region, while the carbon source would still have some impact on the ranking of carbon containing fuels. For hydrogen production, the sites in price region NO4 (see Table 6.2) would achieve lowest production costs, followed by sites in price region NO3. Consequently, there would be eight sites achieving lower production costs than Equinor Tjeldbergodden – which achieves the lowest production costs in the base case.

For carbon containing fuels the results would be almost identical, with sites in price regions NO4 and NO3 outperforming all other sites due to low power prices. However, in this scenario, the site Norcem Kjøpsvik would perform better than the other sites in NO4 and top the list due to high flue gas CO_2 concentration. The site Equinor Tjeldbergodden would be ranked twelfth, due to comparatively low CO_2 concentrations.

6.1.2 National rankings

Cost based rankings on a national level are available in Appendix 9.6 and are discussed briefly in this section.

Sweden

The best sites in Sweden combine relatively low power prices with high potential for by-product utilization. Co-location with SSAB:s iron and steel mills in Luleå and Oxelösund, with the copper-plant Rönnskärsverken in Skellefteå or with Perstorp:s oxy-synthesis plant in Stenungsund, offers potential for high oxygen exports. Alternatively, co-locating e-fuel production with waste incineration plants located close to the major cities Stockholm, Gothenburg, Malmö, or with the two large oil refineries (St1 and Preem) in Gothenburg offer significant potential for heat exports.

Out of these sites, the low power prices of northern Sweden make SSAB Luleå (iron and steel) and Boliden Rönnskärsverken (copper-production) the Swedish sites with lowest production costs.

Norway

For hydrogen and carbon-containing fuels, the Norwegian sites included in this project achieve very low production costs – challenged only by sites in Sweden with significant by-product revenue. In general, the Norwegian sites are competitive because of low power prices, while potential for by-product revenue (especially from heat sales) is comparatively low. However, the best performing Norwegian sites combine low power prices with high by-product potential.

Equinor Tjeldborgodden (a methanol production plant) has the lowest production cost for carbon containing fuels as well as hydrogen and has significant potential for oxygen sales to the methanol plant. For carbon containing fuels, the second-best site is Fortum Oslo Varme (waste incineration) which is close to Oslo's district heating grid. For hydrogen production, the second-best site is instead Noretyl A/S which has a significant oxygen demand. As discussed above, potential for heat exports is less important for hydrogen production, and Fortum Oslo Varme ranks lower (tenth) for hydrogen production.

Finland

Under the PPA-contract assumed in this work, Finnish power prices are higher than those in Sweden and Norway and Finnish sites are generally not competitive with sites in those countries. However, the best performing Finnish site – iron and steel mill SSAB Raahe – ranks very well in a Nordic perspective and is the 20th best site for production of carbon containing fuels while ranking 22nd for production of hydrogen. Similar to the Swedish iron and steel mill SSAB Luleå (ranking 2nd for production of all fuels, Table 6.1 and Table 6.2) this site benefits from large potential for oxygen exports, comparatively cheap carbon capture and economy of scale effects.

Other high-ranking sites from a Finnish perspective are mainly pulp and paper mills (some oxygen exports, large plant size), another iron and steel mill (Outokumpu Chrome) and the Finnsementti Cement plant (low capture costs, large plant size).

Denmark

Denmark has comparatively few industries emitting more than 100 ktonne CO_2/year, although there are several waste incineration plants and thermal heat and power plants above that number. In a Nordic perspective, the Danish power prices are high and Danish sites are not competitive with sites in low cost areas such as Norway or Sweden. There are however several sites with high potential for district heating exports and the best Danish sites include waste incineration plants close to larger cities, and the cement producer Aalborg Portland, all of which benefit from potential heat exports.

As discussed in Section 4.2.3, co-locating e-fuel production with large Danish biogas plants is likely cost-competitive to co-location with the larger point sources mentioned above. However, total fuel volumes that can be produced at low cost are lower.

Iceland

There are only three Icelandic plants emitting more than 100 ktonne CO_2/year and they are all producing aluminium. Therefore, all Icelandic sites achieve very similar production costs. However, one of the aluminum producers – Norðurál Grundartanga – has some potential for heat exports and achieves slightly lower production costs than the other two.

6.2 Ranking based on GHG emission reduction

The site rankings based on GHG emission reduction are determined by the electricity emission factors and the potential for heat exports (allowing emission allocation to the co-produced heat). Using the PPA set-up for electricity supply, electricity emission factors are determined primarily by grid emission factors (two year lagged country averages, see Section 5.6.3) and – to a minor extent – the shares of electricity sourced from the grid and the wind asset. This later factor shows some variation between power price areas, meaning that electricity emission factors will vary between power price areas and not only between countries.

The fifteen sites achieving the highest emission reductions are listed in Table 6.3 These sites achieve the highest emission reduction – and their relative ranking stays the same – for all considered fuels and production years. For sites further down the list, fuel and production year do however have some impact on ranking. The sites included in Table 6.3 are all located in Iceland (with zero-carbon grid electricity) or in Norway, where emission factors for the PPA set-up are below 0.5 gCO_{2eq}/kWh for all investigated years. For comparison, no sites outside Norway and Iceland have emission factors below 5 gCO_{2eq}/kWh. Even if by-product allocation is not considered for the Icelandic and Norwegian sites, the low electricity emission factors are enough to outperform sites in the other Nordic countries.

Note that the rankings in this report are based on the PPA set-up for electricity supply and the TheMA *Best Guess scenario* (see Section 5.6.1). Results for grid electricity and/or the *Emissions Eliminated scenario* can be obtained via the project database[23].

Table 6.3. The 15 best sites for e-fuel production, ranked by GHG emission reduction. This list is identical for all considered fuels and production years.

Site	Branch	Price area	GHG rank
Alcoa Fjarðaál	Non-ferrous metals (Al)	IS	1
Norðurál Grundartanga	Non-ferrous metals (Al)	IS	1
Alcan á Íslandi hf.	Non-ferrous metals (Al)	IS	1
Haraldrud energigjenvinningsanlegg	Waste incineration	NO1	4
Fortum Oslo Varme	Waste incineration	NO1	5
FREVAR - Forbrenningsanlegget	Waste incineration	NO1	6

[23] A database used as basis for the calculations within the present project is publicly available at: www.nordicenergy.org/project/np2x/

Norske Skog Saugbrugs	Pulp and paper	NO1	7
BIR Avfallsenergi	Waste incineration	NO5	8
Borregaard AS, avd. spesialcellulose	Pulp and paper	NO1	9
Alcoa Mosjøen	Non-ferrous metals (Al)	NO4	10
Hammerfest LNG	Natural gas processing	NO4	11
Elkem Salten	Non-ferrous metals (Si)	NO4	11
Norcem Kjøpsvik	Minerals industry (cement)	NO4	11
Elkem Rana AS	Non-ferrous metals (FeSi)	NO4	11
Finnfjord	Non-ferrous metals (FeSi)	NO4	11

It should be noted that the emission reductions achieved by the sites in Table 6.3 are virtually identical (between 97.5 and 97.8 %), and that under the PPA set-up all sites in all countries and for all time periods achieve emission reductions exceeding 80 % – i.e., are well above the 70 % reduction threshold set by the REDII.

The set-up described above describes the main approach used in this project. However, for comparison, Figure 6.2 and Figure 6.3 illustrate example results of the GHG emission calculations for production plants sourcing the entire electricity consumption from the grid, using emission factors for 2025. The 70% emission saving limit of the RED II is illustrated with a red dashed line. It is evident that sites in Norway, Sweden and Iceland reach the 70 % threshold using grid electricity even if no heat is exported, while sites in Denmark do not reach the limit in 2025, even if all heat is exported. Since electricity production is expected to be de-carbonized in all countries, the emission threshold is met also for Finland and Denmark in the years 2035 and 2045, with a similar development as for hydrogen (see Figure 6.4).

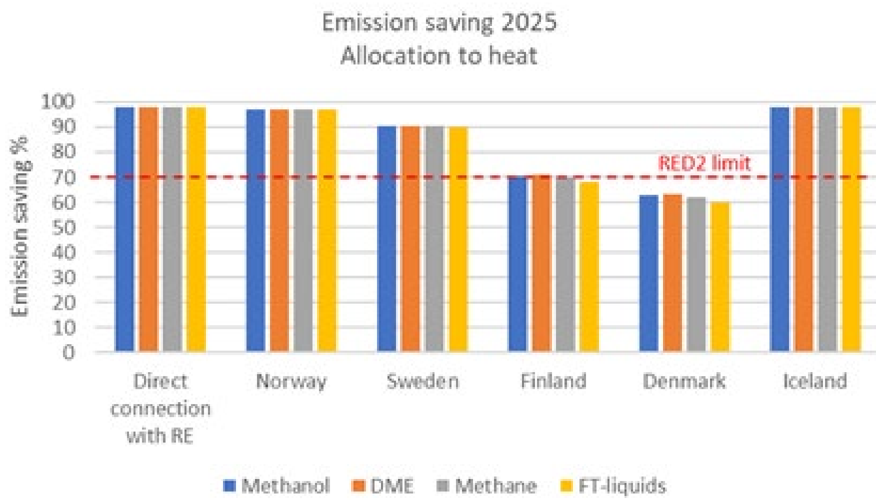

Figure 6.2. Emission saving of the studied fuels with 2025 country average grid emission for electricity and allocation for co-product heat (all heat is assumed to be used)

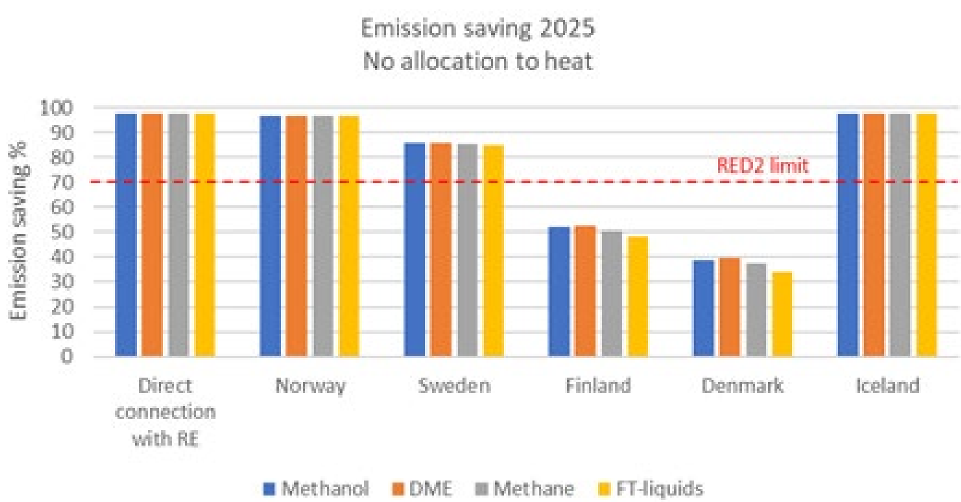

Figure 6.3. Emission saving of the studied fuels with 2025 country average grid emission for electricity and no allocation for co-product heat (no need for heat in the region)

Emission saving results were calculated also for hydrogen with assumptions on the improvement of electrolyser efficiency. Electrolyser efficiency was estimated to be 0.65, 0.7 and 0.75 for years 2025, 2035 and 2045, respectively. The emission of electricity developed similarly as for e-fuels. As the efficiency of the electrolyser improves, less electricity is used for the process. On the other hand, less co-product heat is produced and bigger share of emissions is allocated to the hydrogen.

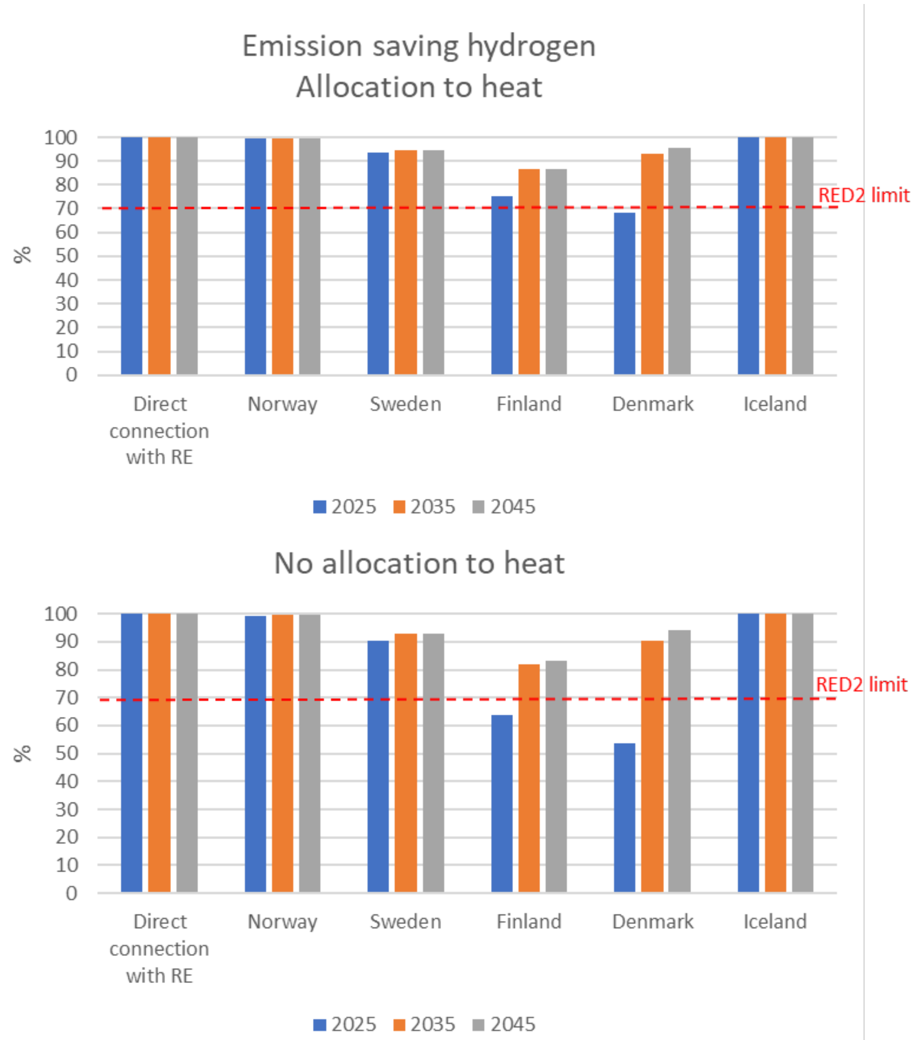

Figure 6.4 Emission saving results for hydrogen with country average grid emission for electricity for the years 2025, 2035 and 2045. Above: including allocation for co-product heat (all heat is assumed to be used); below: no allocation for co-product heat (no need for heat in the region).

It should be noted that the RED II does not represent a full life cycle analysis. More detailed studies on each production site are needed to estimate the GHG emissions of the fuel production more accurately, and to be able to compare the sites in detail. In addition, the GHG emission saving calculations made according to the RED II criteria do not represent a comprehensive analysis on the climate impacts of increasing the production of e-fuels in the Nordic region. To make a more complete analysis on the overall impacts, one would need for example to compare a scenario of increasing the e-fuels production to a baseline without the increased production, and see e.g. the marginal impacts on the emissions of electricity in the region. Thus, there is clearly a need for a wider study on the subject.

6.2.1 Sensitivity analysis on selected parameters

The GHG emission results depend significantly on the emission of electricity used in the e-fuel process. Figure 6.5 shows an example on how the emission saving result changes in relation to the emission of electricity. Figure 6.5 also illustrates the sensitivity of the emission saving result to the allocation of emissions to heat. If no heat can be exported (there is no need for heat in the region) the emission saving result gets more sensitive to the changes of the emission factor of electricity.

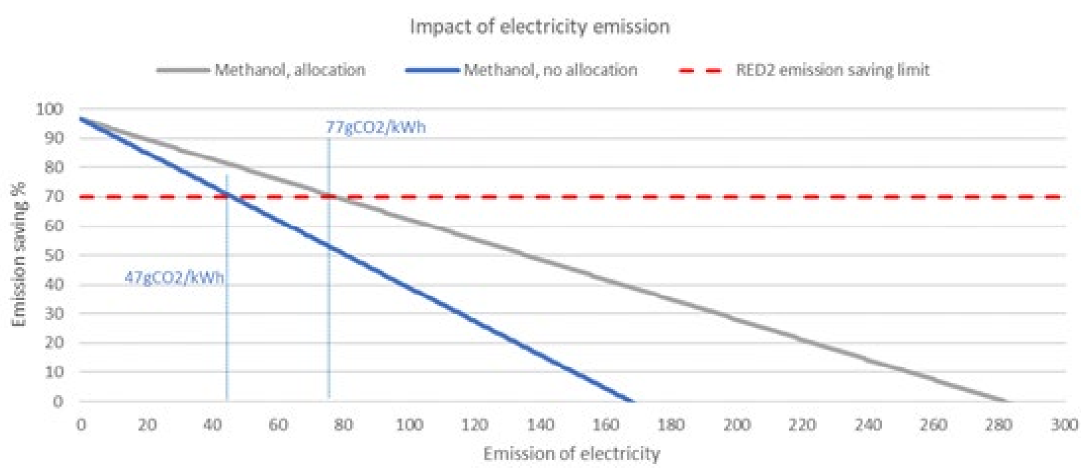

Figure 6.5. Impact of the emission intensity of electricity and allocation to heat on the emission saving result. Example with methanol.

6.3 Ranking based on infrastructure aspects

Based on the qualitative data and discussion provided in Section 5.8, a qualitative ranking of sites (and types of sites) has been made for distribution-related infrastructure only.

The ranking of e-fuel production sites based on the availability of fuel distribution infrastructure is, as discussed in Section 5.8, dependent on both the type of e-fuel produced and the location of the site. The primary conditions of the latter being the availability of a harbor, the closeness to fuel demand center, and – for methane – the availability of a natural gas grid.

Combining the factors described in Section 5.8, a qualitative ranking of both types of aspects for the Nordics and the fuels included in this study, can be illustrated as in Table 6.4. This ranking is valid for the current situation and certainly for the first year in focus for this study (the year 2025). In 2035 or 2045, the situation may have changed, but only if dedicated actions and large investments in the development of infrastructure for the lower ranked alternatives (such as hydrogen) are made.

Table 6.4 Qualitative ranking of e-fuel production sites, based on distribution-related infrastructure.

Type of e-fuel produced / Site location	E-diesel and e-gasoline	Methanol, DME	Methane	Hydrogen
Northern, inland areas (primarily in north Sweden and Finland)				
Central inland areas, close to fuel demand centers (Denmark, south Norway, Sweden and Finland)				
All coastal locations with a harbour (north and central, all countries)				
Areas with a distributed natural gas/bio-methane grid (primarily Denmark and southwest of Sweden)				

When relating this general ranking to the specific top-ranked sites from a fuel production cost perspective, it is clear that many of these have access to a harbour - and therefore can be placed in the most favourable category also from a distribution infrastructure perspective - but not all. The waste incineration plants on the list have in several cases not direct access to a harbour, which seem to the case also for the two non-ferrous metals industries in Norway. The latter are also in the northern part of Norway, and thus not in close location to demand centres, which would mean that they would be categorized as "yellow" or worse for all types of e-fuels, from an infrastructure perspective. For methane production, the top-ranked sites in south and west Sweden (refineries and waste incineration plants) are especially advantageous ("green") from this perspective. When looking at the top-ranked sites for hydrogen production cost and for GHG emissions, the picture is similar in that most sites have access to harbour, except most waste incineration and non-ferrous metal plants.

On the other hand, all sites in Denmark and in the south-west of Sweden - which are not top-ranked from an overall Nordic cost perspective - would be "green" or "yellow" for the distribution of all e-fuels except hydrogen ("orange"), since they are located either in coastal locations or close to demand centres (or both), and in areas with a distributed methane gas grid.

7 Conclusions and policy insights

The ranking analysis in the present study clearly points out the most important site-specific factors for achieving low e-fuel production costs:

- low power prices,
- potential by-product revenue (heat and oxygen),
- the size of the production plant.

Other aspects such as the concentration of the CO_2 source (affecting capture costs) were less important for the final production cost ranking results. The ranking analysis has been performed with focus on four carbon-containing e-fuels (methanol, DME, FT-liquids and methane) and hydrogen. However, an important conclusion is that the ranking results for the different carbon-containing fuels is largely independent of the exact e-fuel produced, why the results are deemed relevant also for other carbon-containing fuels.

Given the large impact of low power prices, Norwegian sites have a significant presence among the sites achieving the lowest e-fuel production costs. The Norwegian sites include plants for the production of chemicals, cement and non-ferrous metals. Other relevant sites include iron & steel mills in Sweden and Finland, which combine large plant sizes with potential by-product revenue from oxygen sales, and relatively low power costs for power and carbon capture. On the other hand, potential heat exports to district heating networks imply that production sites located in or nearby major cities can achieve low production costs, as is exemplified by e.g. the two refineries located in Gothenburg, Sweden, which also have lower power costs than similar sites in Denmark or Finland.

The most significant factor affecting the GHG emission results is the emission intensity of the electricity used. In addition, the ability to allocate emissions to the co-product heat produced in the e-fuel production (i.e. is there demand for heat in the region) can have a significant impact on the results. With the operational setup for power supply considered in this work, namely with power sourced from a portfolio of onshore wind sites complemented by grid power, all investigated sites achieve emission reductions exceeding the 70 % emission saving limit of the RED II. The very low electricity emission factors of the Norwegian and Icelandic electricity grids mean that the highest emission reduction (>95 %) are achieved for sites located in these countries. Hydrogen achieves higher GHG reductions due to a higher conversion efficiency from electricity to e-fuel.

Finally, the e-fuel production sites included in this study have been ranked qualitatively, based on the current infrastructural situation for fuel distribution to customers. Access to a harbor, being an important infrastructural criterion, is the case for nearly all top-ranked sites with respect to production costs. However, some sites resulting in favorable production costs are less favorable from an infrastructure perspective due to their remoteness. On the other hand, all sites in Denmark – not being top-ranked from an overall Nordic cost perspective – have very favorable infrastructural prerequisites, with access to natural gas grid and proximity to demand centers.

The best-performing locations will depend on developments in the e-fuels market and the future development of the European energy system. The best logistical setup for e-fuel production will depend on how the costs of transporting the inputs and final product stack up against variations in power costs, the extent to which the power consumed is renewable, the availability of CO_2 and opportunities to use surplus heat. Co-location at CO_2 sites is assumed to be the best near-term choice to allow for a rapid ramp-up of e-fuel production. Changes within the energy system may change these results.

The greenhouse gas emission savings have been analysed according to RED II. It should be noted that the RED II does not represent a full life cycle analysis. More detailed studies on each production site are needed to estimate the GHG emissions of the fuel production more accurately, and to be able to compare the sites in detail. In addition, the GHG emission saving calculations made according to the RED II criteria do not represent a comprehensive analysis on the climate impacts of increasing the production of e-fuels in the Nordic region. To make a more complete analysis on the overall impacts, one would need for example to compare a scenario of increasing the e-fuels production to a baseline without the increased production, and see e.g. the marginal impacts on the emissions of electricity in the region. Thus, there is clearly a need for a wider study on the subject.

Future developments in the energy system and the complex interactions of e-fuels with the energy system, make it necessary to adopt a larger perspective on the role of e-fuels and P2X processes in general, that were outside the scope of this study. The presented results however can be used for e-fuel siting strategies both on a Nordic and national level, for evaluation of e-fuels GHG reduction potential in relation to other options, as well as a basis for further studies encompassing a larger framework.

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9 Appendix

9.1 Changes and additions to the E-PRTR database

Table 9.1. Changes and additions to the E-PRTR list of large industrial point sources of CO_2

Site	Comment
Nordjyllandsverket (DK)	Missing from E-PRTR (2017). Included based on data from the EU-ETS (2017)
Stora Enso, Varkauden tehtaat (FI)	Missing from E-PRTR (2017). Included based on data from company environmental report (2017).
Metsä Board, Simpele (FI)	Missing from E-PRTR (2017). Included based on E-PRTR data from 2016.
Alholmens Kraft Oy (FI)	Missing from E-PRTR (2017). Included based on E-PRTR data from 2016.
KUOPION ENERGIA HAAPANIEMEN VOIMALAITOS (FI)	Missing from E-PRTR (2017). Included based on data from the EU-ETS (2017)
DONG ENERGY POWER A/S – Skærbækværket (DK)	Missing from E-PRTR (2017). Included based on data from the EU-ETS (2017)
I/S VESTFORBRÆNDING, GLOSTRUP (DK)	Missing from E-PRTR (2017). Included based on data from the EU-ETS (2017)
Energnist Esbjerg (DK)	Missing from E-PRTR (2017). Included based on E-PRTR data from 2016.
Alcoa Mosjoen (NO)	Missing from E-PRTR (2017). Included based on data from the EU-ETS (2017)
SSAB Raahe (FI)	E-PRTR number for 2017 is too low. Data from EU-ETS (2017) has been used instead[1].
Vaskiluodon Seinäjoen (FI)	E-PRTR number for 2017 judged to be incorrect after comparison with EU-ETS. Included using E-PRTR data for 2016.
Neste Naantalin (FI)	E-PRTR number for 2017 judged to be incorrect after comparison with EU-ETS. Included using EU-ETS data (2017).

[1] Note that emissions for the steel plant and the co-located power plant (Raahen Voima) are reported separately in E-PRTR but as one installation in EU-ETS. However, even after combining the separate emissions from E-PRTR the resulting number is too low. It was assumed that the E-PRTR number for the power plant is correct and the emissions of the steel plant was calculated by subtracting the E-PRTR power plant figure from the total emissions in the EU-ETS.

9.2 CO_2 concentration of point sources

Table 9.2. Approximate CO_2 concentration in the flue gases of various industrial activities considered in this work.

vol% CO_2	Industrial activity
5	Aluminium smelters; silicon production; petrochemical cracking; heat and power plants (gaseous fuel); methanol production; iron ore treatment
9	Refineries without hydrogen production; heat and power plants (liquid fuel); copper production; steel processing; oxo-synthesis
13	pulp and paper; refineries with hydrogen production; heat and power plants (solid fuel); ethanol production; FeSi and SiMn production
20	Minerals industry (cement and lime); iron production (direct reduction process); Ferrochrome production
24	Integrated iron and steel mills (blast furnace process); ferromanganese production; hydrogen production (steam methane reforming)
30	Ammonia production; TiO_2 production; secondary steel production

Table 9.3. References and comments relating to the assessment of CO_2 concentrations in the flue gases of industrial activities considered in this work. The notes refer to the numbered list below the table.

Industrial activity	Note	Reference
Aluminum smelters	-	[46]
Silicon production	-	[47], [48]
Petrochemical cracking	-	[34]
Methanol production	-	[49]
Iron ore treatment	1	[50]
Refineries without hydrogen production	-	[34]
Copper production	2	[51]
Ferrochrome production	-	[52]

Steel processing	3	[53]
Oxo-synthesis	4	-
Pulp and paper	-	[34]
Refineries with hydrogen production	-	[34]
Ethanol production	5	-
FeSi and SiMn production	-	[48],[54],[55]
Minerals industry (cement and lime)	-	[34]
Iron production (direct reduction process)	6	[56]
Integrated iron and steel mills (blast furnace process)	-	[34]
Ferromanganese production	-	[55]
Hydrogen production (SMR)	-	[34]
Ammonia production	-	[57]
TiO_2 production	7	[56], [58]
Secondary steel production (electric arc furnace process)	8	[53],[59]

1. Estimate based on data for the cement kilns (Table entry: Minerals industry) and the comparison between iron ore kilns and lime kilns given in [50].
2. Roughly half of the CO_2 derives from the slag fuming plant where the concentration has been estimated to 13-15 % based on [51]. Remaining sources (e.g. fuel boilers fired by oil) likely have lower concentrations and the overall has been estimated to about 10 %.
3. Estimate based on fuel and fuel-to-air ratio given in [53]
4. Estimate based on detailed process knowledge. Small amounts of CO_2 at relatively high concentrations derive from syngas production. Large amounts at relatively low concentration are available from combustion of fuel gas and gaseous and liquid by-products. Average concentration likely around 10 %.
5. Solid fuel boiler using process residue
6. One plant for the production of sponge-iron (direct reduced iron) is included in this work. This plant uses coal as the reducing agent but natural gas for heat supply. The CO_2 concentration has been estimated based on [56] (which uses coal for heat supply and as the reducing agent) and heat supply contribution has been adjusted to reflect a process using natural gas.
7. Most of the process emissions derive from the rotary kiln used for pre-reduction of ilmenite ore using coal [58]. CO_2 concentrations were estimated based on [56].
8. CO_2 source concentrations based on [59]. Relative sizes of emission sources based on [53].

9.3 Industrial oxygen demands

Table 9.4. Oxygen demand for industrial activities considered in this work. The table notes refer to the numbered list below the table.

Industrial activity	tonne O_2/ktonne CO_2 emitted	Note	References
Chemical pulp (and paper)	10	1	[39],[60]
Integrated iron and steel mills (blast furnace process)	90	2	[39]
Secondary steel production (electric arc furnace process)	160	3	[39]
Copper production	1480	4	[39], [61]
Ferromanganese production	70	5	[62], [63]
Steel processing	350	6	[64]
Oxo-synthesis	1060	7	[65]
Methanol production	1160	8	[66]
VCM production	350	9	[67], [68]

1. 28.1 kg O_2 per ADt pulp [39]. Converted to the O_2/CO_2-ratio using CO_2 emission and pulp production data for Södra Cell Värö [60].
2. Based on oxygen consumption and CO_2 emissions of SSAB Raahe in 2015. Oxygen consumption based on [39].
3. Based on oxygen consumption and CO_2 emissions of Outokumpu Tornio. Oxygen consumption based on [39].
4. The oxygen consumption of the copper production plant included in this work (Boliden Rönnskärsverken) was estimated from the oxygen consumption of Boliden Harjavalta given in [39] assuming that the two plants use the same amount of oxygen per unit copper production. Production data for the two plants were obtained from [61].
5. Twice the stoichiometric amount required to decrease the FeMn carbon content from 7wt% to 1wt% [63]. CO_2/O_2 ratio calculated using FeMn production and CO_2 emissions of Eramet Porsgrunn [62].

6. Based on environmental report of SSAB Borlänge [64].
7. Based on CO_2 emissions of Perstorp OXO and the environmental report of its oxygen supplier, AGA Stenungsund [65].
8. Based on production data for Equinor Tjeldbergodden [66]. Please note that this plant uses autothermal reforming. Methanol plants using other processing routes may have different oxygen demand (e.g. zero for steam reforming plants).
9. Oxygen consumption in VCM production based on [67]. CO_2/O_2 ratio calculated based on CO_2-emissions and VCM production of the Noretyl Stathelle plant [68].

9.4 Results from the TheMA power market model

Table 9.5 Power Prices under the Best Guess and Emissions Eliminated Scenarios

Prices in EUR/MWh	**Best Guess**			**Emissions Eliminated**		
	2025	**2035**	**2045**	**2025**	**2035**	**2045**
SE1	37,03	40,96	38,35	47,59	52,97	51,98
SE2	37,19	41,93	39,78	47,67	53,79	52,41
SE3	38,32	42,94	44,69	50,02	55,01	55,16
SE4	38,32	43,17	44,19	50,02	55,73	54,66
NO1	40,42	47,22	42,97	55,47	56,95	54,32
NO2	41,07	47,11	41,92	56,94	56,49	53,84
NO3	38,80	43,76	37,70	50,07	54,43	50,17
NO4	38,56	44,20	37,37	49,20	53,25	49,66
NO5	40,06	47,01	42,81	55,01	56,64	53,68
DK1	43,50	52,08	48,38	63,44	65,40	61,22
DK2	43,38	51,90	49,82	63,05	68,27	64,48
IS	40,00	35,00	32,00	40,00	35,00	32,00
FI	37,77	41,59	41,33	50,49	57,93	60,32

Table 9.6 Renewable Energy Share of Generation for all analyzed bidding zones under the Best Guess and Emissions Eliminated Scenarios.

Prices in EUR/MWh	**Best Guess**			**Emissions Eliminated**		
	2025	**2035**	**2045**	**2025**	**2035**	**2045**
SE1	97 %	97 %	98 %	97 %	97 %	97 %
SE2	96 %	96 %	97 %	96 %	96 %	97 %
SE3	27 %	31 %	80 %	29 %	36 %	64 %
SE4	77 %	76 %	81 %	86 %	84 %	89 %
NO1	99 %	99 %	99 %	99 %	99 %	99 %

NO2	100 %	100 %	100 %	100 %	100 %	100 %
NO3	100 %	100 %	100 %	100 %	100 %	100 %
NO4	99 %	99 %	99 %	99 %	99 %	99 %
NO5	100 %	100 %	100 %	100 %	100 %	100 %
DK1	69 %	90 %	93 %	71 %	90 %	93 %
DK2	66 %	81 %	86 %	64 %	83 %	88 %
IS	100 %	100 %	100 %	100 %	100 %	100 %
FI	31 %	35 %	48 %	30 %	38 %	52 %

Table 9.7 Estimated PPA prices for the Best Guess and Emissions Eliminated Scenarios

Prices in EUR/MWh	**Best Guess**			**Emissions Eliminated**		
	2025	**2035**	**2045**	**2025**	**2035**	**2045**
SE1	38,62	38,34	38,34	40,58	38,60	36,86
SE2	38,62	38,12	38,42	40,97	38,69	37,56
SE3	39,13	38,64	37,79	41,38	39,63	37,82
SE4	39,11	39,26	39,35	41,50	41,54	39,23
NO1	38,03	36,75	34,28	38,19	37,17	34,08
NO2	35,39	34,77	33,35	35,72	35,26	33,10
NO3	33,21	31,05	28,97	33,51	31,53	29,14
NO4	32,50	29,56	26,48	32,69	29,65	26,43
NO5	35,09	33,28	30,78	34,94	33,59	30,84
DK1	39,30	45,10	44,07	42,12	48,17	44,82
DK2	39,05	45,41	44,50	43,02	47,56	45,27
IS	40,00	35,00	32,00	40,00	37,00	32,50
FI	41,11	40,45	40,77	43,16	43,39	43,57

Table 9.8 Effective Renewable Share of energy acquired through a PPA agreement for the Best Guess and Emissions Eliminated Scenario

RES share -PPA	**Best Guess**			**Emissions Eliminated**		
	2025	**2035**	**2045**	**2025**	**2035**	**2045**
SE1	88.28 %	89.46 %	95.66 %	88.51 %	90.27 %	94.56 %
SE2	88.56 %	89.72 %	95.76 %	88.79 %	90.51 %	94.69 %
SE3	90.46 %	91.43 %	96.47 %	90.65 %	92.08 %	95.57 %
SE4	89.81 %	90.84 %	96.23 %	90.02 %	91.55 %	95.27 %
NO1	99.77 %	99.93 %	99.94 %	99.77 %	99.93 %	99.94 %
NO2	99.70 %	99.91 %	99.92 %	99.70 %	99.91 %	99.92 %
NO3	99.73 %	99.92 %	99.93 %	99.73 %	99.92 %	99.93 %

NO4	99.75 %	99.92 %	99.93 %	99.75 %	99.93 %	99.94 %
NO5	99.74 %	99.92 %	99.93 %	99.74 %	99.92 %	99.93 %
DK1	91.29 %	97.31 %	98.32 %	91.71 %	97.95 %	98.68 %
DK2	90.57 %	97.09 %	98.18 %	91.03 %	97.78 %	98.57 %
IS	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
FI	81.55 %	85.42 %	89.19 %	82.40 %	86.49 %	90.97 %

Table 9.9 Carbon intensity per zone for the Best Guess and Emissions Eliminated Scenarios

Carbon intensity (gCO_2/kWh)	**Best Guess**			**Emissions Eliminated**		
	2025	**2035**	**2045**	**2025**	**2035**	**2045**
SE1	11.97	11.80	10.32	11.98	11.83	11.62
SE2	13.16	12.84	10.98	13.16	12.51	11.10
SE3	21.76	14.78	22.19	21.38	13.52	15.01
SE4	78.31	51.37	35.64	45.87	33.14	18.97
NO1	3.80	3.60	3.26	3.80	3.53	3.17
NO2	0.99	0.49	0.44	1.00	0.48	0.39
NO3	0.20	0.17	0.16	0.20	0.16	0.14
NO4	3.02	2.96	2.85	3.02	2.89	2.71
NO5	0.79	0.79	0.79	0.79	0.79	0.70
DK1	123.04	21.44	13.92	64.89	17.13	11.57
DK2	65.88	29.45	18.49	69.67	23.40	14.70
IS	0.00	0.00	0.00	0.00	0.00	0.00
FI	79.50	42.91	42.98	63.43	40.27	35.18

9.5 Input data for case study on hydrogen transport

Table 9.10 Electrolyzer assumptions

		Comment	**Source**
Operational hours	80 %	Of the time	Consistent with siting cost model
Kg H_2 per day	75 000 kg/day	Estimated daily hydrogen production for plant of 200 MW with 60% efficiency and 80% operational hours	Consistent with siting cost model

Table 9.11 Power grid and power price assumptions

		Comment	Source
Build-out distribution grid	276 000 EUR/km		[15]
Transformer station (high voltage)	23 000 000 EUR/station		[16]
Outgoing feeder	312 000 EUR/station	Double bus bar 132 kV	[15]
Lifetime grid components	40 years		Assumed
ROI	6%		Assumed
Power price Luleå (SE1)	38 EUR/MWh	PPA Price for year 2035	See section 5.6.3
Grid tariff Luleå	19 000 000 EUR/year	Grid tariff for Swedish customers with consumption of 140 000 MWh/20MW lie between 15-25 mSEK/year incl mva. Multiply this number by 10 to approximate cost for our 1 750 000 MWh/200 MW facility.	[17]
Power price Aalborg (DK1)		PPA Price for year 2035	See section 5.6.3
Grid tariff Aalborg	19 000 000 EUR/year	Assumed to be similar to Sweden	[17]

		Comment	Source
Power price Iceland	40 EUR/MW	Based on average cost of a portfolio of hydro an geothermal power.	See section 5.6.3
Power price Raggovidda	39 EUR/MW	LCOE + 10%	See section 5.6.3

Table 9.12 Hydrogen infrastructure and transport assumptions

		Comment	Source
Hydrogen pipe CAPEX (rural area)	545 000 EUR/km		[18]
Hydrogen pipe CAPEX (urban area)	1 000 000 EUR/km		[18]
Pipe transport OPEX	478	EUR/MW/year	[18]
Lifetime pipelines	15 years		Assumed
Compressor CAPEX	273 000 EUR	Compression to 70 Mpa	[18]
Compressor OPEX	0,4 EUR/kg H_2		[19]
Liquification (CAPEX + OPEX)	0,5 EUR/kg H_2		[19]
Ship transport (CAPEX + OPEX)	0,5 EUR/kg H_2	For transport of 1000 km	[19]

		Comment	Source
Truck CAPEX	136 500 EUR/truck		[20]
Truck transport OPEX	1,1 EUR/kg H_2	Includes CAPEX for three UMOE 20 feet pressure containers per vehicle. Not including truck. 700 km distance.	[21]
15 days storage in tank (CAPEX + OPEX)			[19]
ROI	6%		Assumed

9.6 National production cost rankings

Norway – Carbon containing fuels

Table 9.13. The ten best sites (cost-ranked) for production of carbon containing e-fuels in Norway

Site	Branch	Price area	National rank	Overall rank
Equinor Tjeldbergodden	Chemicals (Methanol)	NO3	1	1
Fortum Oslo Varme	Waste incineration	NO1	2	3
Norcem Kjøpsvik	Minerals industry (cement)	NO4	3	4
Elkem Rana AS	Non-ferrous metals (FeSi)	NO4	4	5
Finnfjord	Non-ferrous metals (FeSi)	NO4	5	9
Hammerfest LNG	Natural gas processing	NO4	6	10
Ferroglobe Mangan Norge AS	Non-ferrous metals (FeMn)	NO4	7	13
Haraldrud energigjenvinningsanlegg	Waste incineration	NO1	8	14
NORETYL AS	Chemicals (olefins and VCM)	NO2	9	16
Elkem Bremanger	Non-ferrous metals (FeSi and Si)	NO3	10	17

Norway – Hydrogen

Table 9.14. The ten best sites (cost-ranked) for production of hydrogen in Norway

Site	Branch	Price area	National rank	Overall rank
Equinor.Tjeldbergodden	Chemicals (Methanol)	NO3	1	1
NORETYL AS	Chemicals (olefins and VCM)	NO2	2	4
Ferroglobe Mangan Norge AS	Non-ferrous metals (FeMn)	NO4	3	5
Alcoa Mosjøen	Non-ferrous metals (Al)	NO4	4	6
Hammerfest LNG	Natural gas processing	NO4	5	7
Elkem Salten	Non-ferrous metals (Si)	NO4	5	7
Norcem Kjøpsvik	Minerals industry (cement)	NO4	5	7
Elkem Rana AS	Non-ferrous metals (FeSi)	NO4	5	7
Finnfjord	Non-ferrous metals (FeSi)	NO4	5	7
Fortum Oslo Varme	Waste incineration	NO1	10	12

Finland – Carbon containing fuels

Table 9.15. The ten best sites (cost-ranked) for production of carbon containing e-fuels in Finland

Site	Branch	Price area	National rank	Overall rank
SSAB Europe Raahe	Iron and steel	FI	1	20
Stora Enso Oulu	Pulp and Paper	FI	2	54
Outokumpu Chrome	Iron and steel	FI	3	55
Keravan Voimalaitos	Thermal heat and power	FI	4	64
UPM Kymmene Kaukas	Pulp and paper	FI	5	82
Finnsementti Lappeenranta	Minerals industry (cement)	FI	6	94
Metsä Fibre Joutseno	Pulp and paper	FI	7	95
Powerflute	Pulp and paper	FI	8	104
Metsä Fibre Rauma	Pulp and paper	FI	9	110
UPM Kymmene Pietarsaari	Pulp and paper	FI	10	117

Finland – Hydrogen

Table 9.16. The ten best sites (cost-ranked) for production of hydrogen in Finland

Site	Branch	Price area	National rank	Overall rank
SSAB Europe Raahe	Iron and steel	FI	1	22
Stora Enso Oulu	Pulp and paper	FI	2	59
Keravan Voimalaitos	Thermal heat and power	FI	2	59

Pori Energia, Aittaluodon voimalaitos	Thermal heat and power	FI	4	70
Outokumpu Chrome	Iron and steel	FI	5	85
UPM Kymmene Kaukas	Pulp and paper	FI	6	105
Metsä Fibre Joutseno	Pulp and paper	FI	7	115
Powerflute	Pulp and paper	FI	8	125
Metsä Fibre Rauma	Pulp and paper	FI	9	135
Finnsementti Lappeenranta	Minerals industry (cement)	FI	10	142

Sweden – Carbon containing fuels

Table 9.17. The ten best sites (cost-ranked) for production of carbon containing e-fuels in Sweden

Site	Branch	Price area	National rank	Overall rank
SSAB EMEA AB i Luleå	Iron and steel	SE1	1	2
Sävenäsverket	Waste incineration	SE3	2	6
Rönnskärsverken	Non-ferrous metals (Cu (Pb, Zn))	SE1	2	6
Högdalenverket	Waste incineration	SE3	2	6
Preemraff Göteborg	Oil and gas refining	SE3	5	10
St1 Göteborg	Oil and gas refining	SE3	5	10

Sysavs avfallsförbränningsanläggning	Waste incineration	SE3	7	15
SSAB Oxelösund	Iron and steel	SE3	8	24
Boländeranläggningarna	Waste incineration	SE3	9	25
Perstorp OXO	Chemical industry (oxo-synthesis)	SE3	10	30

Sweden – Hydrogen

Table 9.18. The ten best sites (cost-ranked) for production of hydrogen in Sweden

Site	Branch	Price area	National rank	Overall rank
SSAB EMEA AB i Luleå	Iron and steel	SE1	1	2
Rönnskärsverken	Non-ferrous metals (Cu (Pb, Zn))	SE1	2	3
VÄRTAVERKET	Thermal heat and power	SE3	3	23
Sävenäsverket	Waste incineration	SE3	3	23
St1 Refinery AB	Oil and gas refining	SE3	3	23
HÄSSELBYVERKET	Thermal heat and power	SE3	3	23
JORDBRO KRAFTVÄRMEVERK	Thermal heat and power	SE3	3	23
Sävenäs Kraftvärmeverk	Thermal heat and power	SE3	3	23

Denmark – Carbon containing fuels

Table 9.19. The ten best sites (cost-ranked) for production of carbon containing e-fuels in Denmark

Site	Branch	Price area	National rank	Overall rank
I/S VESTFORBRÆNDING, GLOSTRUP	Waste incineration	DK2	1	49
I/S AMAGERFORBRÆNDINGEN	Waste incineration	DK2	2	58
FJERNVARME FYN AFFALDSENERGI A/S	Waste Incineration	DK1	3	80
Aalborg Portland A/S	Minerals Industry (cement)	DK1	4	103
RENO NORD I/S	Waste incineration	DK1	5	111
Leca Danmark A/S	Minerals industry (others)	DK1	6	152
Energnist Esbjerg	Waste incineration	DK1	7	158
A/S DANSK SHELL-RAFFINADERIET	Oil and gas refining	DK1	8	164
Equinor Refining Denmark A/S	Oil and gas refining	DK2	9	168
Fortum Waste Solutions A/S	Waste incineration	DK1	10	191

Denmark – Hydrogen

Table 9.20. The ten best sites (cost-ranked) for production of hydrogen in Denmark

Site	Branch	Price area	National rank	Overall rank
I/S VESTFORBRÆNDING, GLOSTRUP	Waste incineration	DK2	1	77
I/S AMAGERFORBRÆNDINGEN	Waste incineration	DK2	1	77
FJERNVARME FYN AFFALDSENERGI A/S	Waste Incineration	DK1	3	111
Aalborg Portland A/S	Minerals Industry (cement)	DK1	4	143
RENO NORD I/S	Waste incineration	DK1	4	143
Energnist Esbjerg	Waste incineration	DK1	6	190
Leca Danmark A/S	Minerals industry (others)	DK1	7	191
A/S DANSK SHELL-RAFFINADERIET	Oil and gas refining	DK1	8	192
AVV I/S Forbrændingsanlægget	Waste incineration	DK1	9	193
Equinor Refining Denmark A/S	Oil and gas refining	DK2	10	194

Iceland – Carbon containing fuels

Table 9.21. The three Icelandic sites included in this project, ranked by carbon containing e-fuel production cost

Site	Branch	Price area	National rank	Overall rank
Norðurál Grundartanga	Non-ferrous metals (Al)	IS	1	63
Alcoa Fjarðaál	Non-ferrous metals (Al)	IS	2	71
Alcan á Íslandi hf.	Non-ferrous metals (Al)	IS	2	71

Iceland – Hydrogen

Table 9.22. The three Icelandic sites included in this project, ranked by hydrogen production cost

Site	Branch	Price area	National rank	Overall rank
Norðurál Grundartanga	Non-ferrous metals (Al)	IS	1	66
Alcoa Fjarðaál	Non-ferrous metals (Al)	IS	2	67
Alcan á Íslandi hf.	Non-ferrous metals (Al)	IS	2	67

9.7 Production cost calculation – worked example

This appendix gives a worked example of the fuel production cost calculations used in this work. For convenience, relevant tables and equations from chapter 5 of the report are repeated in this section. The considered example is:

Site	Södra Cell Värö
Industry	Pulp and paper (chemical pulping)
CO_2 emissions	1540 ktonne/year
Power price area	SE3
Power price	38.6 EUR/MWh
Heat demand of DH grid (Varberg)	167 GWh/year
e-fuel	Methanol
Production year	2035

Annual fuel production:
According to Table 9.20, the CO_2 demand for methanol production is 0.28 tonne/MWh. Consequently, the theoretical maximum production at Södra Cell Värö is 1540/0.28=5500 MWh_{fuel} per year. At 80 % capacity utilisation, this corresponds to a fuel production capacity of 785 MW_{fuel}. By the overall mass and energy balance (Table 9.20), the corresponding power input is 1.81*785=1420 MW_{el} for methanol production in 2035. This is clearly larger than the maximum electrolyser size of 200 MW_{el}.

Therefore, the plant size is limited by the electrolyser size limit of 200 MW_{el}. Using again the overall mass and energy balance (Table 9.20), the corresponding fuel production capacity is 200/1.81=110.5 MW_{fuel}. At 80 % capacity utilisation, annual fuel production is 774 GWh/year. The CO_2 consumption is 0.28 tonne/MWh_{fuel} (Table 9.20) corresponding to 216 800 tonne/year or 8.6 kg/s.

Table 9.23. Process inputs and outputs for production of the e-fuels considered in this report. Due to the assumed increase in electrolyser efficiency, three values are given for electricity input and electrolyser heat output (year 2025, 2035 and 2045, respectively). Compare to Table 5.4 of the main report.

	Unit per MWh fuel	**Methanol**	**DME**	**Methane**	**FT-liquids**	**Hydrogen**
Electricity input	MWh	1.95 1.81 1.69	1.92 1.79 1.67	2.00 1.86 1.73	2.11 1.96 1.83	1.54 1.43 1.33
CO_2 input	tonne	0.28	0.29	0.21	0.28	0
Steam demand[1,3]	MWh	0.14	0.15	0	0.04	0
Available excess heat[2,3]	MWh	0.78 0.64 0.52	0.79 0.65 0.53	0.75 0.61 0.48	0.83 0.68 0.55	0.46 0.35 0.25
Oxygen output	tonne	0.3	0.3	0.3	0.3	0.3
Steam demand (carbon capture)[3]	MWh	0.24	0.25	0.18	0.24	0
Excess heat (electrolyser)	MWh	0.58 0.44 0.32	0.58 0.44 0.32	0.60 0.46 0.33	0.63 0.48 0.35	0.46 0.35 0.25
Excess heat (synthesis)	MWh	0.1	0.1	0.2	0.2	0
Excess heat (carbon capture)	*MWh*	0.20	0.21	0.15	0.20	0

[1]*Carbon capture steam demand less excess heat from fuel synthesis*

[2]*Excess heat from electrolyser and carbon capture*

[3]*Assumes 13 vol-% CO_2 in flue gases, see Table 5.2*

Investment costs:

The investment costs of the fuel synthesis plant and the electrolyser are calculated using the below formula and parameters:

$$Investment\ (kEUR) = a \cdot (sizing\ parameter)^b$$

Table 9.24. Cost function parameters for hydrogenproduction and carbon containing fuel synthesis. Compare to Table 5.5 of the main report.

Equipment	Sizing parameter	a			b
		2025	*2035*	*2045*	
Alkaline electrolyser	MW power	600	450	300	1
Methane plant	MW fuel	970	970	970	0.7
DME plant	MW fuel	1710	1710	1710	0.7
Methanol plant	MW fuel	1710	1710	1710	0.7

For 110.5 MW methanol production, direct investment costs are 1.710*110.5^0.7 = 46.1 MEUR and for a 200 MW_{el} electrolyser, the direct cost in 2035 is 0.45*200 = 90 MEUR. Indirect costs equal the direct costs and over the system life of the electrolyser, stack replacement costs equal the direct cost. Consequently, the total electrolyser cost is 90*2+90=270 MEUR and the total fuel synthesis cost is 92.2 MEUR.

Using 5 % interest and 25 years economic life, the annualised investment costs per MWh methanol (774 GWh per year) are 270'000'000*0.071/774'000 = **24.7 EUR/MWh_{fuel}** for the electrolyser and 92'200'000*0.071/774'000 = **8.4 EUR/MWh_{fuel}** for the fuel synthesis.

The investment cost of the CO_2 capture plant is determined by the CO_2 flow rate (8.6 kg/s, see above) and the CO_2 concentration in the flue gases, according to:

$$\text{Investment [kEUR]} = \text{a} \cdot \left(\frac{CO_2 \text{ flowrate [kg/s]}}{CO_2 \text{ concentration [vol\%]}} \right)^{\text{b}}$$

Table 9.25. Cost function parameters for the carbon capture plant. Compare to Table 5.6 of the main report.

vol% CO_2	a	b
5	3080	0.60
9	3030	0.61
13	3350	0.65
20	5310	0.56
24	4170	0.65
30	3210	0.74

According to Table 9.23, the CO_2 concentration in pulp mill flue gases is about 13 vol-%, implying that the investment cost for the carbon capture plant is 3.350*(8.6/0.13)^0.65 = 51.1 MEUR, including direct and indirect costs. The specific annualised cost is 51'100'000*0.071/774'000 = **4.7 EUR/MWh$_{fuel}$.**

Table 9.26. Estimated flue gas CO_2 concentrations for various industries. Compare to Table 5.8 of the main report.

vol% CO_2	Industrial activity
5	Aluminium smelters; silicon production; petrochemical cracking; heat and power plants (gaseous fuel); methanol production; iron ore treatment
9	Refineries without hydrogen production; heat and power plants (liquid fuel); copper production; ferrochrome production; steel processing; oxo-synthesis
13	pulp and paper; refineries with hydrogen production; heat and power plants (solid fuel); ethanol production
20	Minerals industry (cement and lime); iron production (direct reduction process)
24	Integrated iron and steel mills (blast furnace process); ferromanganese production; hydrogen production (steam methane reforming)
30	Ammonia production; TiO_2 production; secondary steel production

Operating costs:

Power consumption is dominated by the consumption of the electrolyser. At 200 MW$_{el}$ installed capacity, the annual consumption is 1'402 GWh assuming 80 % capacity utilisation. The plant is in power price area SE3, where power prices in 2035 are estimated to be 38.64 EUR/MWh$_{el}$ (Table 9.7). Specific power costs are: 38.64*1'402'000/774'000 = **69.9 EUR/MWh$_{fuel}$.**

The steam demand of the capture plant is given by Table 9.23.

Table 9.27. Assumed operating parameters of the carbon capture plant. Compare to Table 5.2 of the main report.

	MWh/tonne CO_2	Temperature (°C)
Steam demand	$0.66 \cdot (\text{vol-\%}\ CO_2)^{-0.127}$	120
Electricity input	0.07	-
Excess heat	0.72	100–60

At 13-vol% (pulp and paper mills) and 0.28 tonne CO_2/MWh_{fuel} the total steam demand is 0.24 MWh_{steam}/$MWh_{fuel.}$ According to Table 9.20, 0.1 MWh excess heat per MWh fuel is available from fuel synthesis, and the resulting steam consumption is 0.14 MWh_{steam}/MWh_{fuel}. The steam cost is 17 EUR/tonne (Table 9.25), and assuming 2200 MJ/$tonne_{steam}$, the resulting specific steam cost is **3.8 EUR/MWh_{fuel}.**

Annual operation and maintenance (O&M) costs (excluding stack replacement costs) are 4 % of the direct costs for the electrolyser and fuel synthesis plant, and 4 % of the sum of indirect and direct costs for the carbon capture plant. Consequently, the O&M costs are 0.04*(90+46.1+51.1) = 7.5 MEUR/year. Specific O&M costs are therefore 7'500'000/774'000 = **9.7 EUR/MWh**.

Table 9.28. Assumed utility and by-product prices. Compare to Table 5.7 of the main report.

Steam (EUR/tonne)	Heat (EUR/MWh)	Oxygen (EUR/tonne)	Process water (EUR/tonne)	Cooling water (EUR/tonne)
17	25	50	1	0.02

By-product revenue:

According to Table 9.20, 0.3 tonne oxygen per MWh_{fuel} is produced during methanol production, indicating a total production of 0.3*774'000 = 233'000 tonne/year. However, the oxygen consumption of a chemical pulp mill has been estimated to about 11 tonne/ktonne CO_2 (Table 9.26), indicating that the annual oxygen demand of the Södra Cell pulp mill of this example is about 11*1'540 = 16'940 tonne/year. According to the assumptions of this work, oxygen revenue is only granted for the existing on-site demand. Consequently, the annual revenue at an oxygen price of 50 EUR/tonne (Table 9.25) is 16'940*50=847'000 EUR, or 847'000/774'000 = **1.1 EUR/MWh_{fuel}.**

Table 9.29. Estimated oxygen demand of various industries. Compare to Table 5.9 of the main report.

Industrial activity	tonne O_2/ktonne CO_2 emitted
Pulp (and paper)	11
Integrated iron and steel mills (blast furnace process)	90
Secondary steel production (electric arc furnace process)	160
Copper production	1480
Ferromanganese production	70
Steel processing	350
Oxo-synthesis	1060
Methanol production	1160
VCM production	350

At 774 GWh/year methanol production, excess heat available for export is 0.64*774 = 496 GWh/year (Table 9.20). However, the heat demand of the nearby heat sink (district heating network) is only 167 GWh/year and according to the assumptions of this work (Section 5.5.1) only 25 % of this demand can be covered by excess heat from the electrolyser plant. At 25 EUR/MWh$_{heat}$, annual revenue is 25*0.25*167'000 = 1'043'750 EUR/year, or **1.3 EUR/MWh$_{fuel}$.**

Total methanol production costs are:

24.7+8.4+4.7+69.9+3.8+9.7-1.1-1.3=**118.8 EUR/MWh$_{fuel}$**