GREEN HYDROGEN FROM A SOCIO-ECONOMIC PERSPECTIVE

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Green hydrogen from a socio-economic perspective

A techno- and socio-economic study of different value chains and configurations for green hydrogen with a focus on infrastructure

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Foreword

Hydrogen is anticipated to play a crucial role in the energy transition. As a clean and versatile energy carrier, hydrogen can be used in a wide range of applications, from serving as feedstock in industrial processes and steel production, to acting as a fuel in transportation and as a means of energy storage. This report explores the potential for hydrogen and electrofuels in Sweden by examining the socio-economic aspects of green hydrogen, with particular focus on infrastructure choices, system integration, and long-term development pathways.

The project has been conducted by a multidisciplinary team, led by project manager Lovisa Axelsson (RISE), together with Karin Petterson, Johan Torén, Ehsan Shafiei, and Olivia Cintas (all RISE), as well as Bezawit Tsegai, Erik Östling, Harald Bouma, and Martin Görling (all Sweco). The work has been carried out through a combination of analytical approaches, including literature review, modelling, and stakeholder dialogue, with the aim of providing decision support for strategic choices related to hydrogen development.

The project's reference group has consisted of representatives from Energigas Sverige, Jönköping Energi, Svenska kraftnät, Nordion Energi, Energiföretagen, and Hitachi Energy. The reference group has provided valuable input and perspective throughout the project.

The project has been carried out between January 2022 and December 2025, within Energiforsk's research programme *Hydrogen's role in the energy and climate transition.* Energiforsk's Hydrogen Programme has, between 2021 and 2025, been funded by Alfa Laval Nordic, El i norr, EnBW Sverige, Energiföretagen Sverige, Eskilstuna Strängnäs Energi och Miljö (ESEM), Eulos Vind, Euromekanik, Falkenberg Energi, FuGen Energi, Green Power Sweden, Göteborg Energi, Hitachi Energy, JUMO Mätteknik, Jämtkraft, Jönköping Energi, Karlstad Energi, Kraftringen, Leva i Lysekil, Mälarenergi, Nordion Energi, Oxelö Energi, Permascand, Rabbalshede Energi, Region Stockholm, Region Örebro County, RWE, Siemens Energy, Skellefteå Kraft, Svea Vind Offshore, Svenska kraftnät, the Confederation of Swedish Enterprise, Tekniska verken in Linköping, Toyota, Umeå Energi, Uniper (Sydkraft Hydrogen), Varberg Energi, Vasa Vind, and Öresundskraft.

We wish to extend our sincere appreciation to all who have contributed to the successful completion of this project.

Katja Åström,Energiforsk

Summary

Sweden has set ambitious targets to achieve climate neutrality by 2045, and hydrogen is expected to play an important role in this transition. As a clean and flexible energy carrier, hydrogen can enable climate mitigation across industry, transport, and energy systems. However, realizing this potential requires addressing complex technical, economic, and socio-economic challenges. Decisions about hydrogen production, distribution, and integration will shape not only costs and technical feasibility but also land use, public acceptance, and regional development. Understanding these interactions is essential for designing value chains that are both cost- and resource-efficient.

The analysis in this study covers three representative value chains—green steel, electrofuels, and bioelectrofuels—chosen for their expected significance in Sweden's future energy and industrial landscape. Each value chain is examined under different configurations of hydrogen production and transmission of electricity or hydrogen (grid or pipeline), considering factors such as co-location benefits, utilization of by-products like oxygen and heat, and the implications of centralized versus decentralized production. The study combines a literature review of hydrogen and electricity infrastructure, techno-economic modelling, and socio-economic assessment, complemented by interviews with key stakeholders including infrastructure operators, permitting authorities, and industrial actors. This integrated approach provides insights into both the technical and practical aspects of hydrogen deployment.

The results show that there is no universal advantage for either electricity grids or hydrogen pipelines. The best solution depends on aspects such as local conditions and integration opportunities. Grid-based solutions tend to be more favourable when oxygen or heat recovery can be integrated into industrial processes, as in bioelectrofuel production, while pipelines may become advantageous at large scales or where grid expansion faces constraints. Across all value chains, electricity price is the most influential factor for competitiveness, whereas infrastructure costs—whether grid or pipeline—represents a small share of total production costs of the end-products. Infrastructure choice alone rarely determines feasibility; rather, it interacts with factors such as localization, resource and grid connection availability, and timing of investments.

The techno-economic analysis shows that production costs for green steel range between approximately 460 and 550 €/ton, with hydrogen accounting for roughly 40–45% of the total cost. Infrastructure costs via grid or pipeline are marginal, and the choice of infrastructure has little impact on overall competitiveness. Electricity price is the most sensitive parameter: a 50% increase raises production costs by nearly 20%, outweighing differences between grid and pipeline configurations.

Electrofuels have costs of approximately 140–160 €/MWh, with hydrogen representing 65–80%. Decentralized configurations using grid electricity including the possibility of utilizing oxygen integration at CHP plants for oxyfuel

combustion are most cost-effective. When oxygen demand is absent, centralized and decentralized cases show similar costs, and infrastructure choice becomes less significant.

Bioelectrofuels show costs of approximately 100–120 €/MWh, with hydrogen contributing about half. A key advantage is that oxygen from electrolysis is used directly in the process, avoiding separate oxygen production and favouring grid-based configurations. Heat recovery can further improve economics; when utilized, electricity prices can be substantially higher while maintaining similar overall costs. These factors highlight that co-location and by-product utilization affect the competitiveness in bioelectrofuel systems, though their benefits depend on local conditions and infrastructure.

By-products such as oxygen and heat are produced in large volumes for larger scale systems, which often exceeds local demand, limiting their economic benefits. Revenues have therefore only been included where integration of by-products in the end-product production process is feasible and otherwise considered through sensitivity analysis.

Socio-economic factors add further complexity. Electricity transmission grids benefit from established regulatory frameworks and operational experience, but often face resistance due to visual impact and land-use conflicts. Hydrogen pipelines, though less visible, introduce new safety considerations and operate under evolving regulations. Both infrastructures require extensive permitting and long lead times, and both encounter challenges related to public acceptance. Interviews confirm that early and transparent stakeholder engagement is essential to address concerns and build trust. Co-planning electricity and hydrogen networks could reduce land-use conflicts, improve implementation efficiency, and strengthen local support—particularly in regions where multiple infrastructure projects converge. Such coordination is also important for resilience: while electricity grids offer redundancy through established standards, hydrogen adds storage and sector coupling, enhancing security of supply. A combined system would significantly improve robustness, but hydrogen networks remain partly dependent on electricity for compressor operation, reinforcing the need for integrated planning.

From a system perspective, combined development of electricity and hydrogen infrastructure delivers the greatest socio-economic benefit. Modelling studies at the European level confirm that integrated expansion reduces overall system costs and enhances flexibility compared to grid-only or pipeline-only strategies. This reinforces the conclusion that infrastructure decisions cannot be made in isolation. They must balance cost efficiency, feasibility, and long-term sustainability, while considering regional conditions and integration opportunities. Strategic policy should therefore prioritize flexible, coordinated infrastructure development that supports industrial competitiveness and energy security while minimizing environmental and social impacts.

In summary, the transition to fossil-free fuels and industrial processes requires not only technological innovation but also strategic choices for infrastructure. These choices will shape Sweden's ability to meet climate targets, maintain industrial competitiveness, and build a resilient energy system. The findings presented in this report aim to support informed decision-making by highlighting the interplay between technical, economic, and socio-economic factors in the development of hydrogen infrastructure. While there is no one-size-fits-all solution, the evidence points to the importance of integrated planning, early stakeholder engagement, and a clear focus on cost drivers such as electricity price. By addressing these aspects, Sweden can create the conditions for a successful hydrogen transition that delivers both climate and societal benefits.

Keywords

Technoeconomic analysis, Socioeconomic assessment, Green steel, Electrofuels, Bioelectrofuels, hydrogen infrastructure, electricity grid, hydrogen pipeline, co-location, utilization of by-products

Sammanfattning

Sverige har satt upp mål om att nå klimatneutralitet till år 2045, och vätgas förväntas spela en viktig roll i denna omställning. Som en ren och flexibel energibärare kan vätgas möjliggöra utsläppsminskningar inom industri, transport och energisystem. Att realisera vätgasens potential kräver dock att komplexa tekniska, ekonomiska och samhällsekonomiska utmaningar hanteras. Beslut om produktion, distribution och integration av vätgas kommer att påverka inte bara kostnader och teknisk genomförbarhet, utan även markanvändning, acceptans och regional utveckling. Att förstå dessa samband är viktigt för att utforma värdekedjor som är både kostnads- och resurseffektiva.

Analysen i denna studie omfattar tre representativa värdekedjor – grönt stål, elektrobränslen och bioelektrobränslen – som är valda baserade på deras förväntade betydelse i Sveriges framtida energi- och industrilandskap. Varje värdekedja har analyserats under olika konfigurationer för vätgasproduktion och överföring av el eller vätgas (elnät eller vätgasledning), med hänsyn till faktorer som samlokalisering, utnyttjande av biprodukter såsom syre och värme samt konsekvenser av centraliserad respektive decentraliserad produktion. Studien kombinerar en litteraturgenomgång av vätgasledningar och elnät, tekno-ekonomisk analys och samhällsekonomisk bedömning, kompletterad med intervjuer med nyckelaktörer såsom infrastrukturägare, tillståndsmyndigheter och industriaktörer. Detta angreppssätt ger insikter i både tekniska och praktiska aspekter av vätgasutbyggnad.

Resultaten visar att det inte finns någon universell fördel för vare sig elnät eller vätgasledningar. Den bästa lösningen beror på lokala förutsättningar och integrationsmöjligheter. Nätbaserade lösningar tenderar att vara mer fördelaktiga när syre- eller värmeåtervinning kan integreras i industriella processer, som vid produktion av bioelektrobränslen, medan rörledningar kan bli mer attraktiva vid storskalig produktion eller där nätutbyggnad är begränsad. I alla värdekedjor är elpriset den mest avgörande faktorn för konkurrenskraft, medan infrastrukturkostnader – oavsett nät eller rörledning – utgör en liten andel av den totala produktionskostnaden. Infrastrukturvalet avgör sällan genomförbarheten i sig, utan samverkar med faktorer som lokalisering, resurs- och nätanslutningstillgång samt investeringstidpunkt.

Den tekno-ekonomiska analysen visar att produktionskostnaden för grönt stål ligger mellan cirka 460 och 550 €/ton, där vätgas står för ungefär 40–45 % av den totala kostnaden. Infrastrukturkostnader för nät eller rörledning är marginella, och valet av infrastruktur har liten påverkan på den övergripande konkurrenskraften. Elpriset är den mest känsliga parametern: en ökning med 50 % höjer produktionskostnaden med nästan 20 %, vilket överstiger skillnaderna mellan nät- och rörledningskonfigurationer.

För elektrobränslen är produktionskostnaden cirka 140–160 €/MWh, där vätgaskostnader utgör 65–80 %. Decentraliserade konfigurationer som använder el

från nätet och möjliggör användning av syrgas vid kraftvärmeverk för oxyfuel-förbränning är mest kostnadseffektiva. När efterfrågan på syrgas saknas uppvisar centraliserade och decentraliserade fall liknande kostnader, och infrastrukturvalet blir mindre betydelsefullt.

För bioelektrobränslen är produktionskostnaden cirka 100–120 €/MWh, där vätgas står för ungefär hälften. För bioelektrobränsleproduktion finns behov av syrgas i processen. Vid samlokalisering av elektrolysör kan syre från elektrolysen används direkt i processen och behovet av separat syreproduktion försvinner, vilket gynnar nätbaserade konfigurationer. Värmeåtervinning kan ytterligare förbättra ekonomin; när den utnyttjas kan elpriserna vara avsevärt högre samtidigt som totalkostnaden förblir likvärdig. Dessa faktorer visar att samlokalisering och utnyttjande av biprodukter påverkar konkurrenskraften i bioelektrobränslesystem, även om nyttan beror på lokala förhållanden och infrastruktur.

Biprodukter som syre och värme produceras i stora volymer vid storskaliga system, vilket ofta överstiger den lokala efterfrågan och begränsar deras ekonomiska värde. Intäkter har i basfallen därför endast inkluderats där integration av biprodukter i slutproduktens produktionsprocess är möjlig, och i övrigt hanterats genom känslighetsanalys.

Samhällsekonomiska aspekter tillför ytterligare komplexitet till utvecklingen. Elnät gynnas av etablerade regelverk och driftserfarenhet, men möter ofta motstånd på grund av visuella effekter och markanvändningskonflikter. Vätgasledningar, som är mindre synliga, medför nya säkerhetsaspekter och omfattas av regelverk som fortfarande är under utveckling. Båda infrastrukturalternativen kräver omfattande tillståndsprocesser och har långa ledtider, och båda möter utmaningar kopplade till allmän acceptans. Intervjuer bekräftar att tidig och transparent dialog med intressenter är avgörande för att hantera oro och bygga förtroende. Samplanering av el- och vätgasnät kan minska markanvändningskonflikter, förbättra genomförandeeffektiviteten och stärka lokalt stöd, särskilt i regioner där flera infrastrukturprojekt sammanfaller. Sådan samordning är också viktig för robusthet: medan elnät erbjuder redundans genom etablerade standarder, tillför vätgas lagringsmöjligheter och sektorkoppling, vilket stärker försörjningstryggheten. Ett kombinerat system skulle förbättra robustheten, men vätgasnät är fortfarande delvis beroende av el för kompressordrift, vilket understryker behovet av integrerad planering.

Ur ett systemperspektiv ger en samordnad utveckling av el- och vätgasinfrastruktur störst samhällsekonomisk nytta. Modellstudier på europeisk nivå bekräftar att integrerad expansion minskar systemkostnaderna och ökar flexibiliteten jämfört med strategier som enbart bygger på nät eller rörledningar. Detta förstärker slutsatsen att infrastrukturbeslut inte kan fattas isolerat. De måste balansera kostnadseffektivitet, genomförbarhet och långsiktig hållbarhet, med hänsyn till regionala förutsättningar och integrationsmöjligheter. Strategisk policy bör därför prioritera flexibel, koordinerad infrastrukturutveckling som stödjer industriell konkurrenskraft och energisäkerhet samtidigt som miljömässiga och sociala konsekvenser minimeras.

Sammanfattningsvis kräver omställningen till fossilfria bränslen och industriella processer inte bara teknologisk innovation utan också strategiska val av infrastruktur. Dessa val kommer att forma Sveriges förmåga att nå klimatmålen, bibehålla industriell konkurrenskraft och bygga ett robust energisystem. Resultaten i denna rapport syftar till att stödja välgrundade beslut genom att belysa samspelet mellan tekniska, ekonomiska och samhällsekonomiska faktorer i utvecklingen av vätgasinfrastruktur. Även om det inte finns någon universallösning pekar resultaten på vikten av integrerad planering, tidig dialog med intressenter och ett tydligt fokus på kostnadsdrivande faktorer som elpris. Genom att adressera dessa aspekter kan Sverige skapa förutsättningar för en framgångsrik vätgasomställning som ger både klimat- och samhällsnytta.

Nyckelord

Teknoekonomisk analys, samhällsekonomiska aspekter, grönt stål, elektrobränsle, bioelektrobränsle, vätgasinfrastruktur, elnät, vätgasledningar, samlokalisering, nyttjande av biprodukt.

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1 Introduction

Sweden is one of the countries that has set ambitious targets to achieve a climate-neutral society by 2045. Hydrogen is expected to play a key role in achieving these goals, offering a clean and versatile energy carrier for sectors such as industry, transport, and power. Realizing this potential, however, requires addressing several technical, economic, and systemic challenges.

The development of hydrogen infrastructure is central to this transition. Decisions on where and how hydrogen is produced, transported, and integrated with other systems will influence not only technical feasibility and costs but also broader socio-economic outcomes. Factors such as co-location with industrial facilities, proximity to biogenic carbon sources, and alignment with renewable resource and grid connection availability can create synergies or introduce planning complexities. Similarly, infrastructure choices affect land use, public acceptance, and regional development, making socio-economic considerations an integral part of system design.

This report examines these aspects through three representative value chains; green steel, electrofuel, and bioelectrofuel production, each analyzed under different configurations where green hydrogen is used as feedstock. By combining technical and socio-economic perspectives, the report aims to provide insights into localization rationale, infrastructure options, integration opportunities, and key factors that shape the role of hydrogen in Sweden's energy system, covering both technical and socio-economic perspectives.

1.1 AIM AND SCOPE

The aim of this report is to assess how hydrogen value chain configurations and distribution options influence the design of cost- and resource efficient value chains in Sweden's transition to a climate-neutral society by 2045. The focus is on understanding key technical and socio-economic factors that shape these decisions, including integration opportunities, localization aspects, and system-level interactions between electricity and hydrogen infrastructure.

The scope of the analysis covers three representative value chains where hydrogen is a primary input:

- Green steel production
- Electrofuel synthesis
- Bioelectrofuel production

For each value chain, the report evaluates different configurations of hydrogen production and distribution, considering on-site and off-site production with transmission of electricity or hydrogen, co-location benefits, and utilization of by-products such as oxygen and heat. The analysis combines:

- **Techno-economic analysis** of production costs under varying assumptions of scale, infrastructure, integration opportunities, and resource availability.
- **Socio-economic perspectives**, including permitting processes, land-use implications, resilience and robustness, material usage and public acceptance and engagement for infrastructure development.

The report does not aim to prescribe a single optimal solution but rather to provide insights into how infrastructure choices and localization factors affect competitiveness, integration potential, and system-level outcomes.

The report aims to answer the following research questions:

- How do different configurations of hydrogen value chains and infrastructure choices affect the production costs of green steel, electrofuels, and bioelectrofuels?
- How do integration opportunities and localization aspects influence the selection of hydrogen production and distribution configurations within different value chains?
- How do socio-economic factors such as permitting, land use and public acceptance affect the feasibility of hydrogen pipelines and electricity grid development?

1.2 METHODOLOGY

Within the project, a multi-method approach is used to explore the overarching question of infrastructure choice and how it is influenced by the configuration of different hydrogen value chains. This includes literature review, technoeconomic analysis, stakeholder interviews, and system modelling, all aimed at assessing both the technical and systemic implications of hydrogen infrastructure alternatives.

A literature review is conducted to compare hydrogen distribution via pipelines and electricity grids, identifying technical opportunities and challenges, and synthesizing insights from other projects. Selected hydrogen applications – including green steel, electrofuels, and bioelectrofuels – are analyzed through value chain mapping and supply chain configuration assessments. Technoeconomic data is collected to evaluate factors such as access to oxygen and use of excess heat. Scenarios are developed to compare centralized and decentralized hydrogen production and distribution via pipeline or grid. These are assessed through technoeconomic evaluations and sensitivity analyses.

To include other aspects than strict technoeconomic, the methodology is expanded to include a targeted literature review focusing on broader infrastructure-related aspects such as land use, material and resource requirements, permitting processes, deployment timelines, public acceptance, and system robustness. To complement this, an interview study with relevant stakeholders was conducted to capture practical insights and perspectives on these issues.

Finally, a framework for energy system modelling is described and how a system dynamic approach could be utilized to analyse different questions and development over time. The model could be used to explore how large-scale hydrogen infrastructure could affect the energy market and investment decisions in different industrial applications for hydrogen.

The project is conducted from beginning of 2023 to the end of 2025. Due to the structure of the project and its division into different work packages and a long implementation period, it has not been possible to update and include the most recent research in all work packages. For instance, the infrastructure analysis, which is based on a literature review of hydrogen pipelines and electricity grids, was conducted and completed during 2023 and therefore only includes sources published up to the end of that year.

2 Literature review of hydrogen pipelines and electricity transmission grids

One of the key questions in enabling large-scale hydrogen deployment is how to transport energy from production sites to end users. Two primary approaches exist: transporting hydrogen via dedicated pipelines or transmitting electricity through power grids and producing hydrogen locally via electrolysis. Each option involves distinct advantages and challenges, influenced by factors such as distance, volume, cost, and utilization of byproducts.

This chapter provides a comparison of hydrogen pipelines and electricity grids as transmission technologies based on available literature. Additionally, it identifies key challenges and opportunities, including synergies that could be leveraged to support a successful and sustainable integration of hydrogen into Sweden's energy system. Given that hydrogen pipelines are not commonly established or developed in Sweden on a larger scale, this review focuses more on hydrogen pipelines.

The chapter and work package were conducted and completed during 2023 and therefore only includes sources published up to the end of that year. However, a complementary interview was conducted with Svenska Kraftnät in March 2024.

2.1 TECHNICAL DESCRIPTION OF HYDROGEN PIPELINES

Hydrogen can be transported in pipelines similar to existing natural gas pipelines. Globally there are around 1.2 million km of gas transmission pipelines in operation, with another 200 000 km under construction or consideration.[1] Natural gas pipelines can be repurposed for hydrogen at a lower cost, reducing environmental impact associated with constructing new pipelines and mitigating the risks of stranded assets as natural gas consumption declines.

The cost for a new hydrogen pipeline is estimated to be around 10 – 50 % more expensive than the corresponding pipeline for natural gas. Repurposing existing natural gas pipelines for hydrogen use is estimated to cost 10–25% of the expense of building new dedicated hydrogen pipelines.[2] In a Swedish context however, new hydrogen pipeline construction would be necessary due to the lack of an existing gas grid, apart along the Swedish west coast and a few local grids.

Hydrogen pipelines existing today are predominantly smaller grids in part of Europe and the US, connecting refineries and chemical complexes. These are mainly onshore and have small pipe diameters of less than 18 inches (46 cm). Transmission pipelines over larger distances could be as large as 48 inches (122 cm). These transmission pipelines could connect countries or even continents. One example is the European Hydrogen Backbone, an initiative with several energy

[1] IEA, *Global Hydrogen Review*, 2022

[2] Energimyndigheten, *Underlagsrapport - Förslag till nationell strategi för vätgas, elektrobränslen och ammoniak*, ER 2021:34, 2021.

infrastructure operators who want to connect a dedicated hydrogen pipeline in Europe. This grid will consist of many routes with different pipeline diameters, onshore and offshore and mostly repurposed natural gas pipelines.[3]

Transporting large quantities of energy in the form of hydrogen pipeline is considered the most cost-efficient alternative. When pipelines operate at around 75 % of their design capacity, economy of scale is reached at approximately 1 000 000 tonnes hydrogen per year for 20-inch (51 cm) pipelines and 2 000 000 tonnes hydrogen for 48-inch (122 cm) pipelines, assuming transport distances of 2 000 – 2 500 km[4].

According to the literature review, the operating pressure in hydrogen pipelines varies from 30 – 90 bars, with lower pressure or around 30 – 50 bar in smaller pipelines (distribution or local) and higher pressure of around 40 – 80 in larger pipelines. In distribution pipelines, the lower operating pressure usually eliminates the need for additional compression of hydrogen after production. On the contrary, the higher pressure in transmission pipelines typically necessitates further compression.[5] There are different approaches to network design, either with smaller compressor stations every 100 km or larger stations every 600 km, which maintain the pressure in the pipelines. Both approaches are assessed to result in similar costs per distance. The compression capacity is estimated to 190 – 330 MWe per 1 000 km.[6]

2.2 COMPARATIVE COST ANALYSIS

The development of efficient and cost-effective hydrogen infrastructure is essential for the successful integration of hydrogen as a viable energy carrier. Several studies have been reviewed to evaluate the costs associated with hydrogen infrastructure. The following chapter provides a comparative cost analysis of the various aspects of hydrogen pipelines and the electricity transmission grid based on a literature review.

Considering the relatively limited prevalence of hydrogen pipelines compared to electricity grids, the literature review has focused on pipeline infrastructure. Thus, an in-depth literature review focusing on the key cost parameters for pipelines such as capital expenditures (CAPEX), operational expenditures (OPEX), compressor units and storage options are detailed in Appendix A:.

2.2.1 CAPEX

Infrastructure development normally requires substantial upfront investments. A key factor for hydrogen infrastructure, whether for pipelines or electricity transmission grids, is hence the initial investment costs (CAPEX).

[3] European Hydrogen Backbone, *How a dedicated hydrogen infrastructure can be created,* 2020
[4] IEA, *Global Hydrogen Review,* 2022
[5] European Hydrogen Backbone, *How a dedicated hydrogen infrastructure can be created,* 2020
[6] European Hydrogen Backbone, *How a dedicated hydrogen infrastructure can be created,* 2020

The literature reviews shows that CAPEX for hydrogen pipelines usually ranges between 1.4 – 3.4 MEUR/km. [7] Several factors, such as location, terrain, pipeline diameter and pipeline distance can impact the total CAPEX. The CAPEX for repurposing existing natural gas pipelines is lower as previously mentioned compared to construction of new pipelines. Repurposing costs primarily involve enhancing the pipe material to resist degradation caused by hydrogen. The CAPEX for repurposed pipelines is 15 – 20 % of new pipes and could be as low as 0.19 MEUR/km.[8]

In comparison, CAPEX for power transmission lines is estimated to range between 1 – 2.3 MEUR/km.[9] According to an interview with Svenska Kraftnät, the CAPEX commonly ranges between 1.8 – 2.2 MEUR/km, usually adding around 1 GW in power capacity. The CAPEX for electricity transmission grids also varies depending on several factors such as the capacity of the line, location (open landscape vs densely populated area) and onshore vs offshore connection. During recent years, electricity transmission costs, mainly material costs, have been increasing both in Sweden and across Europe. Furthermore, the cost for adding power transmission capacity also increases if a substation is required. Depending on the circumstances this station could increase the CAPEX by up to 50 MEUR.[10]

2.2.2 OPEX

Another key factor of infrastructure is the operating costs, which include activities such as maintenance, repairs, inspections and monitoring. Hydrogen pipeline infrastructure tends to have lower operational compared to the higher investment costs. This is mainly due to the high-quality material that must be used in the construction of pipelines to avoid embrittlement problems caused by hydrogen.[11] Operational costs can vary from 0.8% to 5% of CAPEX, however this is dependent on for instance the size of the pipeline and distance.[12] For electricity transmission grids the operational costs are estimated to 1 % of CAPEX.[13]

2.2.3 Distance and volume

The distance and volumes of pipelines can vary. Distribution pipelines carry volumes of around 10 – 100 tonnesH2/day and can vary from smaller local networks (1 – 10 km), urban (10 – 100 km), inter-city (100 – 1 000 km) and intercontinental (1 000 – 10 000 km). Transmission pipelines carry volumes from

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[7] See Table 6 in Appendix A:.

[8] European Hydrogen Backbone, *Extending the European Hydrogen Backbone – A European hydrogen infrastructure vision covering 21 countries*, 2022.

[9] Vendt and Wallmark, *Prestudy H2ESIN: Hydrogen, energy system and infrastructure in Northern Scandinavia and Finland*, 2022

[10] Svenska Kraftnät. Interview 2024-03-18.

[11] Energimyndigheten, *Underlagsrapport - Förslag till nationell strategi för vätgas, elektrobränslen och ammoniak*, ER 2021:34, 2021.

[12] See Table 6 in Appendix A:.

[13] AEMO, *Transmission Cost Report*, 2021.

around 100 – 1000 tonnesH2/day and can range the same distances as distribution pipelines.[14]

Similarly, electricity grid networks can be constructed on local or regional levels, to larger national or cross-border interconnected transmission lines. Voltage levels in Sweden for local distribution lines are usually below 40 kV, regional level of around 130 kV and transmission lines 230 kV or 400 kV.[15]

Both methods of energy transport have their benefits and trade-offs. However, for high-volume, long-distance transport of energy when the desired end-product is hydrogen, pipelines are generally 2 to 4 times more cost-effective than overhead power lines delivering the same energy, excluding storage costs. This cost advantage becomes particularly relevant at scale, where a single large-diameter hydrogen pipeline can carry as much energy as multiple high-voltage transmission lines.[16]

2.2.4 Lifetime

The literature review shows that the lifetime of hydrogen pipelines and electricity transmission lines are in quite similar range, amounting to around 40 – 55 years for hydrogen pipelines[17], and around 40 years for electricity transmission grids.[18]

2.2.5 Other hydrogen infrastructure components

Storage

Another key infrastructure component is hydrogen storage. Storage can enhance the resilience for a hydrogen consumer and increase flexibility in power use for electrolysis for a hydrogen producer. Further, hydrogen storage can facilitate the balancing of production and consumption differences in a system. As the pressure in hydrogen pipelines can vary depending on the input and output volumes, hydrogen storage can be used to balance the system. If the pressure in the pipelines is low, hydrogen can be injected from storage to balance for instance a higher consumption rate in the system.

There are various solutions to store hydrogen, both for longer and shorter time periods as well as in different volumes. Further, hydrogen can also be stored in different physical forms, i.e. gaseous or liquid and at different locations in the value chain - co-located with hydrogen production or consumption. Factors such as volumes, period for storage as well as geographical conditions can affect the preferred storage method. Some examples of different hydrogen storage solutions are lined rock caverns, salt caves and depleted gas fields for gaseous hydrogen.

[14] Energimyndigheten, *Underlagsrapport - Förslag till nationell strategi för vätgas, elektrobränslen och ammoniak*, ER 2021:34, 2021.
[15] Svenska Kraftnät, https://www.svk.se/om-kraftsystemet/oversikt-av-kraftsystemet/sveriges-elnat/, published 2022-12-08, used 2023-10-09.
[16] European Hydrogen Backbone, *Analysing future demand supply, and transport of hydrogen*, 2021
[17] See Table 6 in Appendix A:
[18] Vendt and Wallmark, *Prestudy H2ESIN: Hydrogen, energy system and infrastructure in Northern Scandinavia and Finland*, 2022.

The literature review shows that the levelized cost of storage (LCOS) vary between 0.2 – 4.2 EUR/kgH2, depending on the type of storage, physical form and size. Only one of the reviewed reports has presented CAPEX and OPEX values, estimated to 55 EUR/kgH_2 and OPEX of 2% of CAPEX. The lifetime is found to be around 30 – 40 years.[19] For more information on storage, see Energiforsk's hydrogen storage report.[20]

Recompression units

In terms of hydrogen pipelines, the system relies on additional, essential components that can affect both capital and operational costs. One such component is recompression units, which are necessary to maintain pressure and flow within the pipeline system. The CAPEX for recompression units is according to literature review ranging from 2.2 to 6.7 MEUR/MWe and OPEX estimated to approximately 1.7 % of CAPEX. The expected lifetime of recompression units is between 15 and 30 years, indicating on replacement needs during the pipeline's lifetime.[21]

2.2.6 Total hydrogen pipeline cost

In the literature review, the total costs for hydrogen transmission via pipelines have also been analysed, presented in Figure 1. Reported cost levels reveals a difference in different studies, ranging from 0.04 – 0.58 EUR/kgH_2, with the differences largely stemming from varying assumptions across the studies. For example, some analyses include hydrogen storage, which increases the overall transmission cost. Additionally, certain reports account for both new and repurposed pipelines and consider different geographical contexts, all of which influence the final cost estimates. A detailed overview of the assumptions used in the cost analyses is provided in Table 9 in Appendix A:

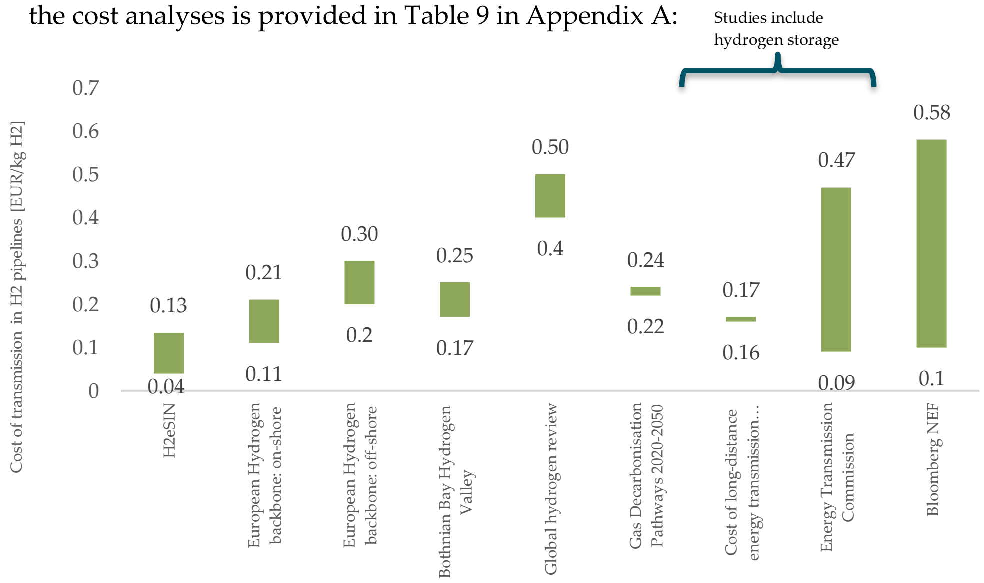

Figure 1. Total cost of transmission in hydrogen pipelines, EUR/kg H2.

[19] Table 8 in Appendix A:
[20] Frost, M m.fl., *Hydrogen storage – knowledge overview and technical analysis*, Energiforsk rapport 2025:1092, 2025.
[21] Table 7 in Appendix A:

2.3 SWOT ANALYSIS

This chapter presents a SWOT (Strengths, Weaknesses, Opportunities, and Threats) analysis for hydrogen pipelines and electricity transmission grids, based on the literature review. Rather than introducing new analyses, it synthesizes insights from multiple sources to provide an overview.

The analysis begins with strengths such as flexibility in locating electrolysers when pipelines are implemented and the potential to repurpose natural gas infrastructure for hydrogen transport. It then addresses weaknesses, including technical challenges and high capital investment requirements.

Opportunities include utilizing residual heat and enabling additional stakeholders to access hydrogen via pipeline networks. Finally, threats that could hinder progress are outlined, such as regulatory barriers and public acceptance issues.

Table 1. SWOT analysis for Hydrogen Pipeline transmission.

Aspects	***Strengths***	***Weaknesses***
"Internal" factors	Little interference with the power grid - hydrogen production will support grid stability by "absorbing" the intermittent power production and reducing wind power curtailment Avoided costs for strengthening the grid capacity. Excess power production can be stored in hydrogen. Mild landscape interference and small land use areas occupied for energy transmission during operation. Flexible electrolyser/hydrogen production localisations	Hydrogen supply vulnerability at disruptions - no redundancy (unless complemented with minor storages at the user sides, which requires some overcapacity in the pipelines) Difficulties to take larger future unknown demand changes into consideration when dimensioning. Relative expensive investment costs, requires large hydrogen transmission to be justified.
"External" factors	***Opportunities***	***Threats***
	Electrolyser residual heat can be utilized for district heating Improved business opportunities for wind power companies due to stable offset Existing natural gas pipelines can be converted to hydrogen pipelines (10-25% of cost for new construction). Sweden has two natural gas networks, (600 km transmission along the west coast, with 2 000 km distribution and in and around Stockholm with 500 km distribution). Good possibilities for other hydrogen actors, both hydrogen providers and users, to connect to a pipeline. Possibilities to coordinate the pipeline construction with other infrastructure investments	Unclear legislation framework for how to implement Hydrogen infrastructure. Uncertainties around regulation of hydrogen infrastructure. Low local knowledge capacity in Sweden regarding large scale gas infrastructures. Technology of pipelines under development. Potentially low public acceptance for an underground pipeline.

Table 2.SWOT analysis for Power transmission.

	Strengths	***Weaknesses***
"Internal" factors	Proven and reliable transmission technology with vast locally available knowledge capacity. Electrolysers can act as balancing agents and load regulators, providing system services to the power grid.	Additional electric storages, such as batteries may be needed to fully minimize underutilization of intermittent renewable power.
"External" factors	***Opportunities***	***Threats***
	Electrolyser by-products such as oxygen and heat can potentially be utilized on, or near, site. Improved business opportunities for wind power companies due to stable offset and increased value-factor	Construction of several additional 400 kV transmission lines will have a large visual and direct impact on the landscape and land use.

2.4 OUTLOOK IN NEIGHBOURING COUNTRIES

In Appendix B: an outlook of infrastructure development in Denmark, Finland Norway and Germany is presented, which was finalised in 2023. Below is a short summary of current developments since that chapter was finalised.

Significant efforts are underway across Sweden and Europe to expand electricity grids and develop hydrogen pipelines. One example is the European Hydrogen Backbone (EHB) initiative, launched in 2020. EHB, which includes 33 energy-infrastructure operators in Europe, aims to accelerate Europe's decarbonisation by promoting hydrogen infrastructure, focusing on hydrogen pipelines.[22] The vision is a cross-border network in Europe of 53 000 km by 2040, using both new and repurposed pipelines. [23]

In Denmark, the Danish government approved the so called "Syvtallet" in 2025, which includes the construction of a hydrogen pipeline between Denmark and Germany. The project is run by the Danish state-owned operator Energinet and is scheduled to be completed around 2030. The aim is to enable the export of green

[22] European Hydrogen Backbone. *The European Hydrogen Backbone (EHB) initiative | EHB European Hydrogen Backbone*, 2022

[23] European Hydrogen Backbone, *Extending the European Hydrogen Backbone – A European hydrogen infrastructure vision covering 21 countries*, 2022.

hydrogen from Danish offshore wind power to Germany. Denmark has provided state loans and operating support to secure the project's implementation.[24]

In Sweden, the government tasked Svenska kraftnät in 2024 with proposing how electricity and hydrogen transmission infrastructure could be co-planned to support the industrial transformation in Norrbotten and Västerbotten. The proposal, delivered in August 2025, outlined a plan for the period 2024–2033 and emphasized socio-economic efficiency, security of supply, and integration with Sweden’s long-term energy policy. The analysis concluded that a large-scale hydrogen infrastructure would only become a competitive complement to electricity grid expansion under scenarios of high hydrogen demand. While electricity grid reinforcement alone appeared more economically robust in most scenarios, Svenska kraftnät highlighted that socio-economic factors such as energy security, land use and feasibility favor a combined approach. The conceptual vision presented in the report proposes a stepwise development, starting with isolated hydrogen pipeline segments that could later form part of an interconnected system. This approach would reduce the need for extensive grid expansion and allow flexibility in adapting to uncertain hydrogen demand[25].

One of the ongoing hydrogen pipeline projects in Sweden and Finland is the Nordic Hydrogen Route (NHR), where Nordion Energi and Gasgrid Finland are collaborating to develop hydrogen pipeline infrastructure in the Gulf of Bothnia by 2030. Another major initiative is the Baltic Sea Hydrogen Collector (BHC), a collaboration between Nordion Energi, Gasgrid Finland, Cascade and Copenhagen Infrastructure Partners, aiming to connect Finland—and potentially Sweden and Denmark—to Germany by 2030. In 2025, the BHC project received an EU grant of €15.3 million from the Connecting Europe Facility (CEF) programme to fund preparatory activities, including technical (pre-FEED), regulatory, and environmental assessments[26]. As part of NHR, the first planned segment between Luleå and Letsi was intended to support fossil-free fertilizer production through a partnership with Fertiberia and Lantmännen. However, in late 2025, the hydrogen production facility in Letsi was halted due to insufficient electricity supply, leading to the cancellation of the fertilizer plant in Luleå. Nordion Energi will continue developing the hydrogen infrastructure, though at an adjusted pace. The Letsi–Luleå segment remains part of a broader pipeline system, and consultations have begun for a planned route from Örnsköldsvik around the Gulf of Bothnia to Vaasa in Finland.[27]

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[24] Pipeline Journal. https://www.pipeline-journal.net/news/denmark-approves-construction-major-hydrogen-pipeline-germany, published 2025-05-09, used 2025-11-10.

[25] Svenska Kraftnät, *Förslag till hur el- och vätgasinfrastruktur kan samplaneras i Norrbottens och Västerbottens län*, 2025

[26] Hydrogen Europe. https://hydrogeneurope.eu/eu-funding-supports-preparatory-work-for-the-baltic-sea-hydrogen-collector-bhc/ published 2025-10-30, used 2025-11-10.

[27] SVT, *Gödselfabrik i Luleå skrotas – brist på el stoppar satsning*, https://www.svt.se/nyheter/lokalt/norrbotten/godselfabrik-i-lulea-skrotas-brist-pa-el-stoppar-satsning, published 2025-11-05, used 2025-11-12

3 Techno-economic assessment of hydrogen value chains

As hydrogen development advances, understanding how infrastructure choices and value chain configurations affect costs and resource efficiency becomes increasingly important. Previous studies have compared electricity and hydrogen distribution via grids and pipelines, examining optimal production, storage, and transportation within the context of electricity, gas and other infrastructure28,29. However, the impact of specific value chain configurations on overall cost and integration opportunities has not been extensively analyzed.

This analysis provides a techno-economic assessment of different configurations for hydrogen use in three representative value chains: green steel production, electrofuels, and bioelectrofuels. These value chains are designed to reflect typical conditions in the Swedish context. The primary aim is to highlight localization aspects and options for energy transmission within each value chain, rather than comparing different technologies.

3.1 INPUTS AND ASSUMPTIONS FOR TECHNO-ECONOMIC ANALYSIS

The techno-economic assessment compares the cost and infrastructure implications of different value chain configurations. It includes key parameters such as electrolyser investment, electricity pricing, and the choice of grid or pipeline, providing insight on how localization and infrastructure choices affect overall feasibility. The general assumptions and input data that apply across all three value chains are presented in this section, while assumptions specific to each individual value chain and configurations are described in their respective section. Labour costs have not been included in the analysis.

[28] Vendt M. and Wallmark C., *Prestudy H2ESIN: Hydrogen, energy system and infrastructure in Northern Scandinavia and Finland*, 2022

[29] Karjunen, H. et al., *Bothnian Bay Hydrogen Valley - Research Report*, 2021

Table 3. Common inputs for techno-economic analysis for all value chain configurations.

	Parameter	Unit	Value
	Discount rate	%	5
Electrolyser	CAPEX	EUR/kW	1500
	OPEX % of CAPEX	%	3%
	Lifetime	years	15
	Full load hours	h	8 000
	Electricity demand	MWh/tnH_2	50
	Efficiency	%	66
	H_2O demand	tnH_2O/tnH_2	10
	O_2 production	tnO_2/tnH_2	8
	Waste heat production	MWh/tnH_2	
Prices for resources and by-products	Electricity price	EUR/MWh	40
	Feedwater cost	EUR/m^3	1
	Oxygen value	EUR/kgO_2	0.065
	Excess heat (low temp)	EUR/MWh	20
	Excess heat (high temp)	EUR/MWh	40
Hydrogen pipeline[30]	Levelised cost – for steel case	EUR/kgH_2	0.1
	Levelised cost – for electrofuel and bioelectrofuel	EUR/kgH_2	0.19
	Levelised cost – for decentralized electrofuel case	EUR/kgH_2	0.28
	Lifetime	years	50
Electricity transmission grid	CAPEX	MSEK/km	25
	Lifetime	years	50
Transformer station	CAPEX	BSEK	0.5 * 50%
Hydrogen storage	CAPEX	EUR/kgH_2	55.4
	OPEX	% of CAPEX	2%
	No of days	days	5

[30] Different costs are used for the different value chains and case due to different amount of hydrogen volumes and distances.

Electrolyser

For the electrolyser, a CAPEX of 1 500 €/kW was used, though it is important to note that CAPEX costs can vary, depending on for instance technology and size. The future development is expected to somewhat bring down costs, however this includes uncertainties.[31]

Electricity price

Electricity prices naturally fluctuate throughout the year and are subject to uncertainties regarding future trends, particularly due to recent volatility and the expanded development of intermittent electricity production. Additionally, electricity prices for hydrogen production can vary depending on if merchant prices or a Power Purchase Agreement (PPA) is used. In this case study, the electricity price was set at 40 EUR/MWh, which can be compared to the average spot prices in Sweden during 2024 at; SE1: 25.1 EUR/MWh, SE2: 24.6 EUR/MWh, SE3: 35.8 EUR/MWh, SE4: 49.7 EUR/MWh.[32]

Electricity grid tariffs have not been included in the comparative techno-economic analysis, as there is currently no established framework for hydrogen pipeline tariffs. The future structure and level of such tariffs remain uncertain, although frameworks are under development on an EU level, which makes a meaningful comparison between electricity grid and pipeline costs impractical. Therefore, tariffs have been excluded from the analysis.

Energy transportation

In terms of infrastructure and energy transportation, the following assumptions provide a framework for understanding the costs associated with the pipeline and grid infrastructure in the different value chain configurations.

When energy is transported through electricity transmission grids to on-site hydrogen production, a new transmission grid line is built with a CAPEX of 25 MSEK/km. Further, a transformer station is assumed to be required to facilitate the integration and distribution of energy within the grid. The cost for the transformer station is at 0.5 BSEK, and is assumed to be shared among relevant stakeholders, resulting in a 50% share for this configuration.

Energy transportation through hydrogen pipelines involves the construction of a transmission or distribution pipeline spanning over an urban distance depending on the scenario. It is assumed that the pipeline connects point A to point B, although it can be assumed that a larger pipeline network would be built out in the future. The levelized cost of the pipeline is defined differently for each value chain to reflect the differences in volumes and distance assumed for the different cases. Steel value chain uses 0.075 EUR/kgH2 with a hydrogen volume of 240 tonnes/day, electrofuels and bioelectrofuels value chains 0.14 EUR/kgH2 with a hydrogen volume 60-82 tonnes/day while a cost of 0.241 EUR/kgH2 is used in the

[31] Ramboll, *Achieving affordablegreen hydrogen production plants*, 2023.

[32] Nordpool. https://data.nordpoolgroup.com/auction/day-ahead/prices?deliveryDate=latest&currency=EUR&aggregation=YearlyAggregate&deliveryAreas=EE,LT,LV,AT,BE,FR,GER,NL,PL,DK1,DK2,FI,NO1,NO2,NO3,NO4,NO5,SE1,SE2,SE3,SE4, published n.d, used 2025-10-10

decentralized case for electrofuels with a daily hydrogen volume of 27 tonnes/day to each site.[33] As the literature review shows in Figure 1 the estimated costs for pipelines include a large range and in turn uncertainties.

For all value chains and configurations, a hydrogen storage is assumed to be co-located with the industrial site where the steel or fuel is produced.

3.2 HYDROGEN FOR STEEL APPLICATION

The steel industry in Sweden is a significant consumer of fossil-fuels, for which green hydrogen offers a promising alternative for decarbonisation. This value chain analysis hence focuses on hydrogen application for the steel industry, although it is applicable for other end-users both within for instance the industrial and transport sector.

In the steel production process, green hydrogen can be used for the reduction of iron ore. The method for reducing iron ore to a porous sponge iron is called direct reduction (DR), which includes oxygen being removed from the iron ore as hydrogen is added to the process in a shaft furnace (see Figure 2). Historically, this has been done by the reductant coal or coke, which hence can be replaced by green hydrogen to produce green steel.[34]

After the sponge iron is produced, an Electric Arc Furnace (EAF) is used to molten it to crude steel (CS). In this process, oxygen can be injected to EAF to oxidize carbon fines into CO, which can reduce electricity consumption. The crude steel can then be processed in various steps to produce different end-products, usually initially by continuous casting and hot rolling.

Green steel can be produced in various ways. For instance, it can be produced from virgin material i.e. iron ore (primary steel making), by 100 % scrap (secondary steel making) or a mixed of both. For the simplicity of this case study, an assumption of 100% iron ore for the steel production is assumed.

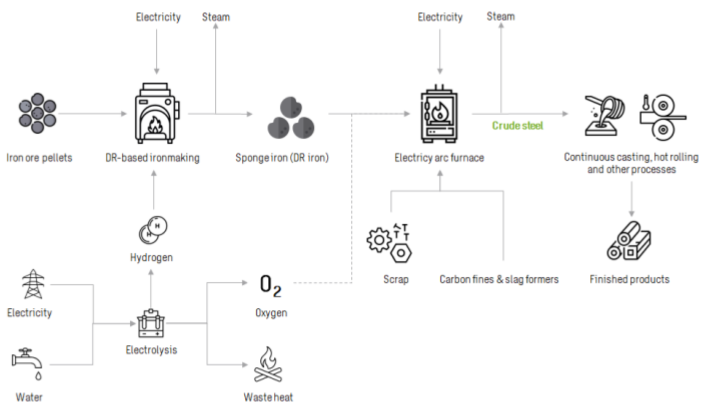

Figure 2. Simplified scheme of steel production process using green hydrogen for DRI-reduction. Does not include output streams from DRI and EAF.

[33] Energimyndigheten, *Underlagsrapport - Förslag till nationell strategi för vätgas, elektrobränslen och ammoniak*, ER 2021:34, 2021.
[34] Hybrit. https://www.hybritdevelopment.se/, published n.d.

3.2.1 Hydrogen value chain configurations

The value chain analysis is based on an arbitrary steel production site, with the assumption of limited electricity grid capacity to provide electricity for the hydrogen production. Energy must hence be transported to the arbitrary site either by newly constructed electricity transmission lines or hydrogen pipelines. In Figure 3, the two value chain configuration scenarios are presented.

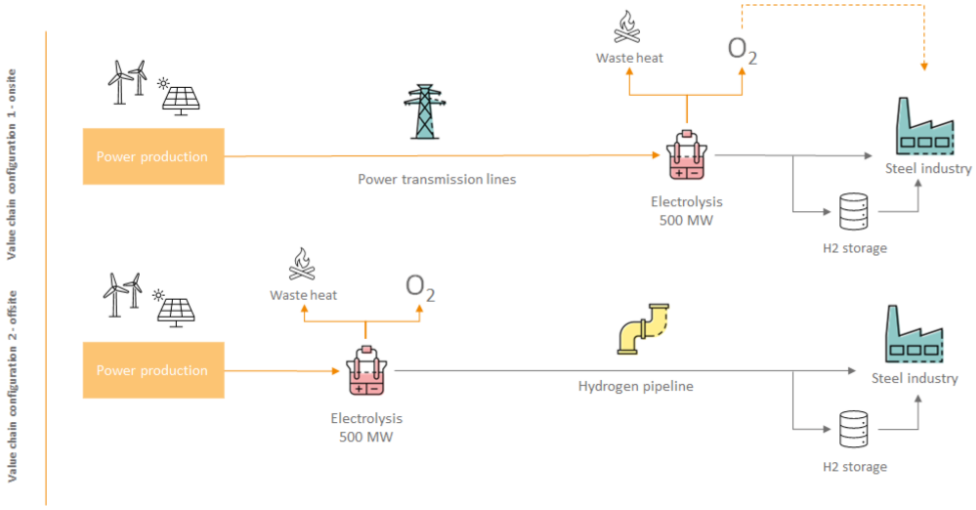

Figure 3. Value chain configuration scenarios for hydrogen application in the steel industry.

Value chain 1: On site hydrogen production

The first value chain scenario evaluates on-site hydrogen production, with an electrolyser co-located with the steel production site. This value chain configuration includes electricity being transferred from the power production site through newly built power transmissions lines to the electrolyser of a distance of 100 km. To increase redundancy an on-site hydrogen storage is added into this scenario. The hydrogen storage method is chosen to be compressed hydrogen and includes 5 days storage.

Integrating an electrolyser with a steel plant presents opportunities for utilizing residual flows from the electrolyser in the steel production process. As oxygen can be used in the EAF for oxidation, it is assumed that a small share of the produced oxygen from the electrolyser is consumed in steel production process, amounting to c. 19 000 tonnes. No external offtake of oxygen is included in the base case scenario. One of the observations is that the oxygen-market is quite saturated. Despite emerging new applications, the substantial output from larger-scale electrolyser presents challenges. For potential oxygen offtake, see more in Energiforsk's oxygen report.[35]

Waste heat from the electrolysis process is considered low-grade (60 to 80 °C depending on the technology). While one opportunity for utilizing the waste are for e.g. HVDC in the electrolyser building, this has not been included as these volumes are assumed to be small and as it is not dependent on the location of the

[35] Gustavsson, M. et. al. *Potential use and market of Oxygen as a by-product from hydrogen production*, Energiforskrapport, 2023:937, 2023.

electrolyser in relation to the steel plant. For external offtake, low-grade waste heat could be employed for district heating or industrial use, though many district heating networks would require upgrades to accommodate the lower temperatures. External offtake of waste heat has not been included in the base case scenario, but is included in the sensitivity analysis.

Value chain 2: Off-site hydrogen production

The second value-chain configuration scenario considers hydrogen production off-site. Subsequently, the hydrogen produced is transported to the steel production site through a dedicated 100 km hydrogen pipeline.

Further, a hydrogen storage system capable of holding five days' worth of production is included. The storage could be situated either next to the off-site electrolyser or at the steel plant. In this scenario, it is assumed that the storage is located at the steel production plant to enhance redundancy at the production unit.

In this scenario, oxygen used in the EAF is assumed to be sourced externally, given that the electrolyser is not situated on-site at the steel plant. Although there could be potential for external offtake of oxygen and waste heat in this scenario, this has not been considered in the base case scenario with the same reasoning as for value chain 1.

3.2.2 Techno-economic data

For the value chain configuration analysis, the size of the arbitrary steel production plant was decided after analysing current plans for green steel production in Sweden. SSAB and LKAB's project HYBRIT has plans for a very large scale, with an electrolyser capacity in the size of 2 – 3 GW by 2050. In a nearer future, STEGRA is proceeding with their plans of building a 700 – 800 MW electrolyser. The size had not been officially decided by April 2024.[36] HYBRIT's demonstration plant is aiming for a 500 MW electrolyser, which would produce around 1 280 ktonnes of crude steel (CS) annually.[37]

For both value chain scenarios, an electrolyser capacity of 500 MW was decided for both value configurations, although this is relatively small compared to the current plans for green steel production. This would produce around 80 ktonnes of hydrogen annually, with the assumptions of operating at full capacity for 8 000 hours per year. The shaft and electric arc furnace were then sized based on the crude steel production. Further, around 640 ktonnes of oxygen and 960 GWh of waste heat is produced annually from the electrolyser. Although 200 GWh of waste heat is produced in the steel production, use of this has not been included in the techno-economic analysis as it would be the same for both value chain configurations.

Both value chain configuration scenarios included a hydrogen storage capacity designed for 5 days of storage, equivalent to 1 200 ktonnes hydrogen annually. This represents 1.5% of the total annual hydrogen production. The necessity of

[36] Bodentx. https://bodenxt.se/en-av-varldens-storsta-vatgasanlaggningar/, published 2023-04-19, https://bodenxt.se/en-av-varldens-storsta-vatgasanlaggningar/

[37] Hybrit. https://www.hybritdevelopment.se/en/hybrit-demonstration/, published n.d,

hydrogen storage has been a topic of debate among large-scale steel industries that are developing hydrogen production. In this case, storage is included and assumed to enhance redundancy and flexibility.

Table 4. Techno-economic data for hydrogen for steel production

Energy and mass flows	Value chain 1: On-site	Value chain 2: Off site	Unit
Crude steel production	1.28	1.28	Mtn / year
Hydrogen production	80	80	ktn / year
Electrolyser size	500	500	MW
Hydrogen storage	120	120	hours
Waste heat production electrolyser	960	960	GWh
Oxygen production	640	640	ktn/year
Steam from DR	92	92	GWh
Steam from ERI	114	114	GWh
Infrastructure length (pipeline and electricity transmission)	100	100	km
Total power demand	625 (on-site)	125 (on-site), 500 (off-site)	MW

Sensitivity analysis

As several parameters in the techno-economic analysis include uncertainties, a sensitivity analysis has been performed to better understand individual and combined parameter's effects on the cost results. The sensitivity analysis has been performed on the following parameters:

- External offtake of 10% of produced oxygen (64 ktonne) and 10% of waste heat volumes (96 GWh) from the electrolyser for value chain 1.[38]
- External offtake of all produced waste heat and oxygen for value chain 1.
- Electricity price increase by 50% to 60 €/MWh for value chain 2 (off-site)
- Increased storage to 10 days for value chain 1 (on-site)
- High case for the levelised cost of hydrogen pipelines following large range of costs. The sensitivity includes a levelized cost of 0.14 €/kgH2.

[38] Note that the location of the electrolyser is not relevant for the external offtake of waste and oxygen, as this depends on the area of where the electrolyser is located.

3.2.3 Results of techno-economic assessment

Figure 4 below presents the estimated levelized production costs of crude steel using green hydrogen in the DRI process. Considering the two value chain configurations and the conducted sensitivity analysis, the crude steel production cost varies between 428 – 556 €/tCS. The costs are mainly dominated by the operating steel production costs, while the hydrogen related costs (H2 production and storage), account for 41 – 47% of the total production cost.

The assessment of the base cases reveals no significant cost differences between pipeline and grid-based value chain configurations. The production cost is reduced by 1% in the pipeline base case, following lower energy transportation costs (c. 50% lower compared to electricity).

Overall, energy transportation costs – both via electricity and hydrogen – represent minimal shares of the overall production cost, with 2.3% in the grid-based case and 1.4% in the pipeline case. Increased costs for hydrogen pipelines in the sensitivity analysis also shows negligible impact on the overall production cost.

Although co-locating the electrolyser with the steel plant enables integration of residual oxygen into the steel production process, it has minimal impact on the production cost. The small volumes of oxygen used in the EAF result in negligible cost differences, whether oxygen is sourced from the electrolyser or purchased externally.

The sensitivity analysis which includes 10% external offtake of waste heat and 10 % of oxygen also shows negligible effects on the production cost. External offtake of 96 GWh of waste heat leads to a cost reduction of 3.3 €/tCS, while the 64 kt offtake of oxygen results in a c. 1.5 EUR/tCS revenue, reducing the production cost by 1%. Although only 10% of the residual flow from the electrolyser has been assumed, these are large volumes in comparison to current market sizes. The 64 kt of oxygen represents c. 5% of the total oxygen consumption in Sweden[39], while 96 GWh of residual heat corresponds to c. 0.2% of Sweden's total heat production.[40]

When assuming 100% offtake of waste heat and oxygen, the production cost is reduced by 10%. The substantial waste heat volume of 960 GWh may however be challenging to fully capitalize on. For context, the district heating network in Luleå, where SSAB is transitioning to green steel production, delivered c. 800 GWh of heat in 2024.[41] The decommissioning of traditional blast furnaces will however remove significant volumes of excess heat that have historically supported large parts of Luleå's district heating network, which to 90% consists of residual heat. Luleå Energi is currently exploring ways and technicalities to integrate excess heat from the new steel production process and other industrial activities as the blast

[39] Gustavsson, M., et al., *Potential use and market of Oxygen as a by-product from hydrogen production*, Energiforskrapport 2023:937, 2023

[40] SCB, https://www.scb.se/hitta-statistik/statistik-efter-amne/energi/tillforsel-och-anvandning-av-energi/arlig-energistatistik-el-gas-och-fjarrvarme/pong/tabell-och-diagram/fjarrvarme-gwh/, updated 2025-10-08, used 2025-11-19.

[41] Energimarknadsinspektionen, https://ei.se/om-oss/statistik-och-oppna-data/tekniska-uppgifter---fjarrvarme, reviewed 2025-10-03, used 2025-11-26.

furnace is phased out.[42] In terms of the value chain configurations, this transition presents an opportunity to capitalize on the large volumes of residual heat generated by electrolysers, offsetting the loss of excess heat from the blast furnace and benefiting existing locations that rely on the blast furnace residual heat. In terms of oxygen, the 100% offtake represents c. 50% of the current oxygen market in Sweden. Benefiting from external oxygen offtake depends on finding suitable offtakers, regardless of whether the electrolyser is co-located with the steel production plant or not.

The results on the other hand show strong sensitivity for electricity price. In the sensitivity analysis where the price for the off-site hydrogen production is increased to 60 €/MWh, the production cost increases by 18% compared to the pipeline base case. Although no results are shown for the grid-based case, the impact is similar since electricity costs account for c. 35% of the production cost.

The sensitivity analysis reveals that a larger the hydrogen storage capacity has minor impacts on the overall costs. However, a larger storage could improve the resilience of the steel production site by increasing resilience of the site. Further, increased operational flexibility could contribute to larger system dynamics by balancing energy demand and supply, aiding in grid or pipeline stability.

Potential revenues from free allocations within the EU ETS has not been considered. As iron and steel production are subject to EU ETS, transitioning to renewable fuel consumption can lead to a surplus of free emission allocations as CO2 emissions decreases. These allocations could be sold and further reduce crude steel production costs until the free allocations are phased out according to CBAM in 2034, in which iron and steel are included.

[42] Luleå Energi, https://www.luleaenergi.se/nyheter/har-ar-vi-forberedda-pa-alla-scenarion/, published 2025-09-11, used 2025-11-30.

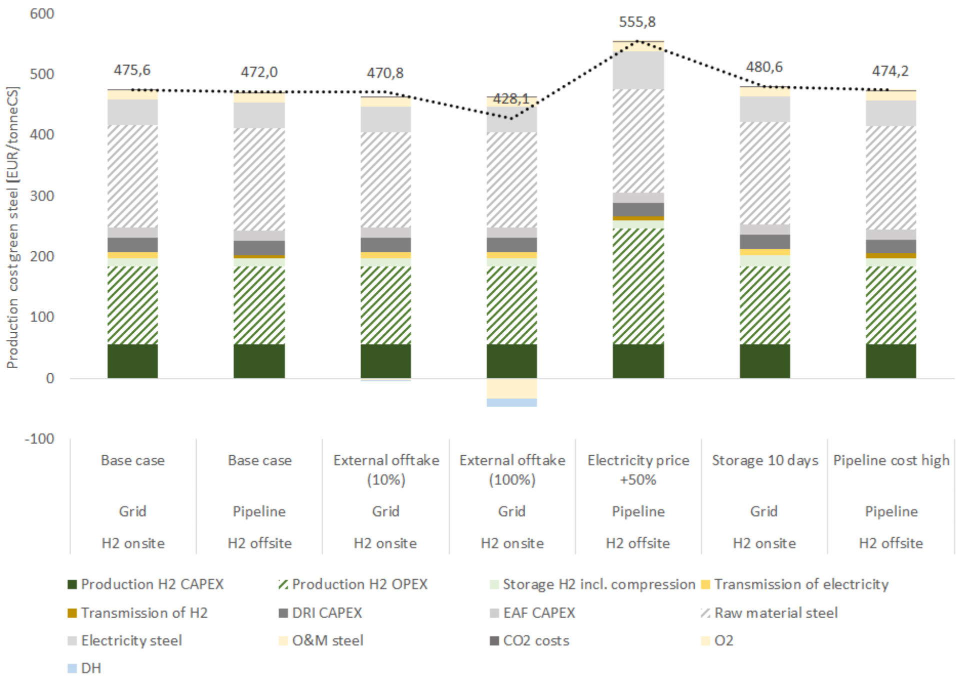

Figure 4. Estimated crude green steel production costs, including sensitivity analysis for the two value chain configurations.

3.3 HYDROGEN FOR ELECTROFUEL PRODUCTION

A possible future major use of hydrogen is the production of electrofuels. A range of different fuels and chemicals can be produced from hydrogen and carbon dioxide. Carbon capture and utilization (CCU) can be accomplished using a variety of technologies where one of the technologies of interest in a short- and medium-term is catalytic synthesis, in which carbon dioxide is combined with hydrogen in a catalytic reactor to produce different products, such as methanol, methane and hydrocarbons.

This chapter focuses on the value chain of production of methanol. Figure 5 illustrates a high-level flow diagram for electrofuel production.

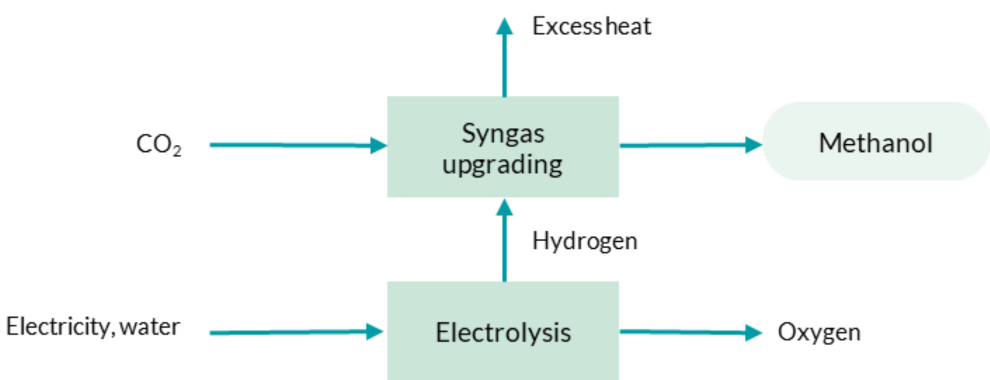

Figure 5. High-level flow diagram for electrofuel production.

3.3.1 Electrofuel value chain configurations

Figure 6 illustrates the value chain configurations analysed for electrofuels. For each case, hydrogen/electricity distribution through grid or pipeline is considered.

Decentralized production involves capturing CO_2 from flue gases at a combined heat and power (CHP) plant within a district heating system. The CO_2 is then converted on-site into fuel, in this case, methanol, through the addition of hydrogen. This process is carried out simultaneously at multiple facilities, and the resulting product is subsequently distributed to the end users.

Centralized production also involves capturing CO_2 from several CHP plants. However, the captured CO_2 is transported to a central facility, preferably located near the end user of the fuel (in this case, ideally adjacent to a port). At this central site, the conversion of CO_2 and hydrogen into methanol takes place. Both cases produce the same quantity of methanol.

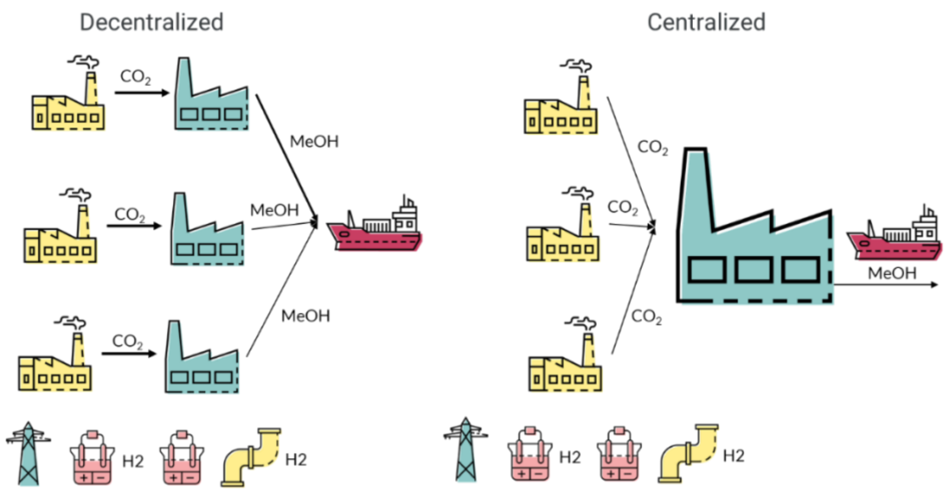

Figure 6. Studied value chain configurations for electrofuels. Two configurations of electrofuel production are modelled - decentralized and centralized. For both configurations, the hydrogen production could be both on-site and off-site, where on-site hydrogen production requires electricity grid for energy transmission and off-site hydrogen production requires pipeline for hydrogen transmission.

3.3.2 Techno-economic data

Table 5 presents key input data for electrofuels (mainly based on Mesfun et al., 2023[43]) and the sizes is in line with the planned production sites in Sweden. Note that the district heating production is the extra heat produced when electrofuel production is implemented (not the heat production in the CHP plant). The technical and economic data and assumptions that are common for all value chains are presented in section 3.1.

Table 5. Key input data for electrofuels

Energy and mass flows	Decentralized (per plant)	Centralized (total)	Unit
Methanol production	278	834	GWh/year
Captured CO_2	85	254	ktn/year
Power usage (tot)	66	198	MW
Electricity usage (tot)	529	1586	GWh/year
Power usage (for H2)	63	188	MW
Hydrogen usage	10	31	ktn/year
Oxygen production	81	(244)	ktn/year
District heating production	31	(92)	GWh/year
Hours of hydrogen storage	40	40	hours
Infrastructure length (pipeline and electricity transmission)	70	70	km

[43] Mesfun et. al., *Electrification of Biorefinery Concepts for Improved Productivity-Yield, Economic and GHG Performances,* 2023, Energies, 16 (21), DOI: 10.3390/en16217436.

3.3.3 Results of techno-economic assessment

Figure 7 presents the resulting production costs for electrofuels. The total cost for electrofuels varies between 156-161 €/MWh fuel for the different cases under the base assumptions (according to Table 3 and Table 5). The cost is largely dominated by hydrogen-related expenses, accounting for 67–79% of the total cost. The infrastructure share of the cost varies between 4-8% of the total cost.

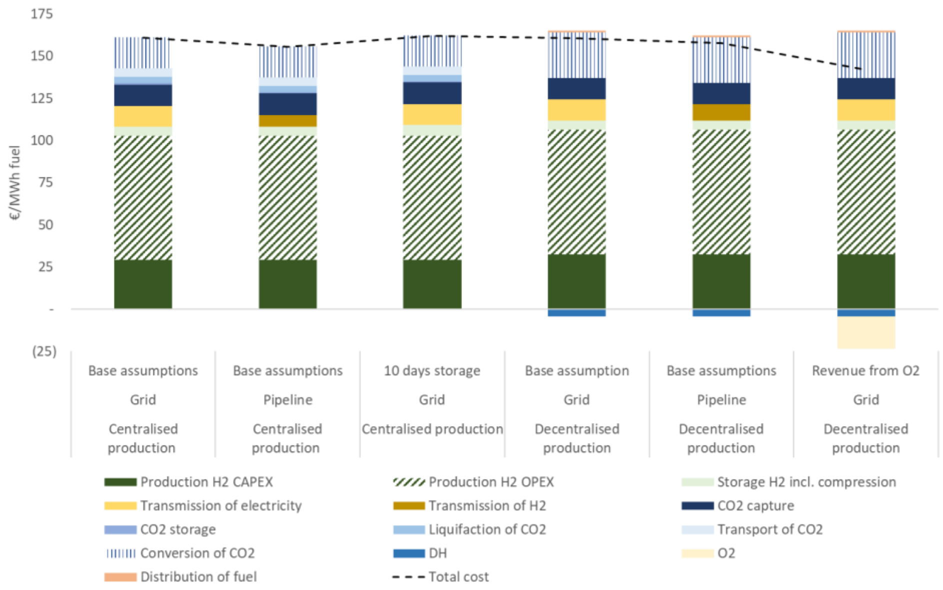

Figure 7. Production cost for electrofuels with the two main configurations presented - decentralized and centralized fuel production. For both configurations, hydrogen production could be both on-site and off-site, where on-site hydrogen production requires electricity grid for energy transmission and off-site hydrogen production requires pipeline for hydrogen transmission – this is represented by grid or pipeline in the figure. In addition, two sensitivity analysis are presented, 10 days of storage and revenue from O2.

If no demand for oxygen is assumed, as in the base assumptions, centralized and decentralized production have similar costs. In the centralized case, additional costs for CO_2 liquefaction and transport are offset by lower costs for CO_2-to-fuel conversion, as this is carried out at a larger scale compared to the decentralized case. Similarly, grid and pipeline distribution have comparable costs when there is no oxygen demand. Pipelines show slightly lower costs in the centralized value chain configuration due to the assumption of a lower specific transmission cost for hydrogen.

When hydrogen is distributed via pipelines, no oxygen production occurs at the CHP plant. Similarly, in the case of centralized production, no oxygen production takes place at the CHP plant, as hydrogen is utilized during the conversion of CO_2 into fuel, which occurs centrally (not at the CHP plant).

The lowest cost is observed in the case of decentralized production, with distribution of electricity via the grid to the electrolyser, and the assumption that there is a demand for oxygen produced by the electrolyser. Oxygen could be utilized in the combustion process at the CHP plant (oxyfuel combustion), facilitating subsequent CO_2 capture. If there is an oxygen demand, the configuration with grid case and on-site hydrogen production can tolerate an electricity price 23 % higher than the pipeline case while still achieving the same total cost for decentralized production. This means that for pipeline distribution to remain competitive under these conditions, it would require a lower electricity price compared to grid distribution.

The revenue stream from district heating in these cases is based on excess heat from fuel production that can be supplied to a district heating system at the required temperature levels. This corresponds to about 91 GWh of heat and reduces production costs by approximately 3%. If excess heat from the electrolyser—amounting to nearly 360 GWh—could also be utilized for district heating, total production costs could be reduced by an additional 5%. Although this represents a much larger quantity of heat, its lower temperature level limits its value.

3.4 HYDROGEN FOR BIOELECTROFUELS

In the production of biofuels, a significant portion of the biogenic carbon is released into the atmosphere as carbon dioxide. By incorporating electricity or hydrogen to varying degrees, it is possible to achieve higher carbon efficiency, directing a larger share of the biogenic carbon into desired products (see e.g. Mesfun et al., 2023). These processes represent a combination of biofuels and electrofuels, commonly referred to as bioelectrofuels or hybrid fuels. Figur 8 illustrates a high-level flow diagram for bioelectrofuel production.

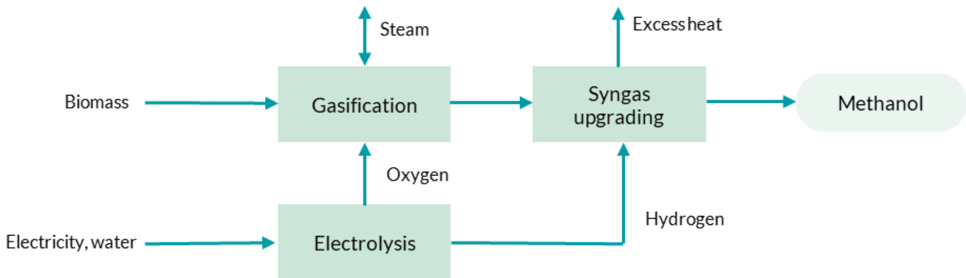

Figure 8. High-level flow diagram for bioelectrofuel production.

3.4.1 Bioelectrofuels value chain configuration

Figure 9 illustrates the value chain configurations analysed for bioelectrofuels: Case 1, Case 2, and Case 3. In Case 1, fuel production is situated near the biomass resources, resulting in longer transportation distances to the end-users. Conversely, Case 3 represents a configuration where the production facility is closer to the end-users, requiring longer transportation distances for the biomass feedstock. Case 2 presents a scenario where fuel production is co-located with a district heating system, allowing excess heat from the production process to be utilized for district heating. For each case, two different ways of hydrogen/electricity distribution are considered: (i) distributing electricity via the grid and producing hydrogen via electrolysis at the bioelectrofuel production facility, (ii) distributing hydrogen produced through electrolysis to the production site via pipeline.

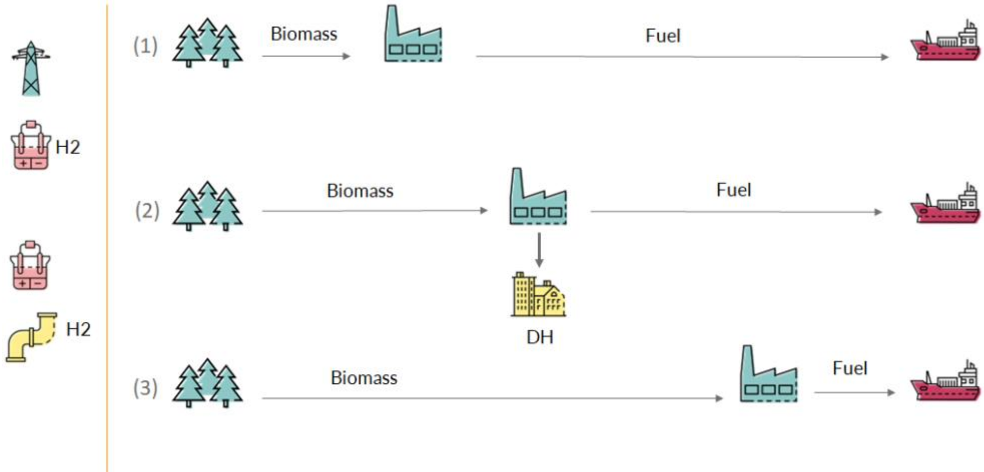

Figure 9. Studied value chain configurations for bioelectrofuels. Three configurations of bioelectrofuel production are modelled – with different resources transported. Case 1, fuel production is situated near the biomass resources, resulting in longer transportation distances to the end-users. Case 2, fuel production is co-located with a district heating system, allowing excess heat from the production process to be utilized for district heating. Case 3 fuel production is closer to the end-users, requiring longer transportation distances for the biomass feedstock. For each configuration the hydrogen production could be both on-site and off-site, where on-site hydrogen production requires electricity grid for energy transmission and off-site hydrogen production requires pipeline for hydrogen transmission.

3.4.2 Techno-economic data

Table 6 presents key input data for bioelectrofuels mainly based on Mesfun et al.,.[44] The fuel produced is liquified methane and is produced from forest residues via an oxygen blown gasification process. The process is boosted with hydrogen, leading to a higher carbon efficiency, i.e. more fuel is produced from the biomass resource.

[44] Mesfun et. al., *Electrification of Biorefinery Concepts for Improved Productivity-Yield, Economic and GHG Performances*, 2023, Energies, 16 (21), DOI: 10.3390/en16217436.

Table 6. Key input data for bioelectrofuels.

Energy, mass flows and prices		
Methanol production	1150	GWh/year
Biomass usage	800	GWh/year
Power usage (tot)	145	MW
Electricity usage	1161	GWh/year
Power usage (for H2)	139	MW
Hydrogen usage	22	ktn/year
Oxygen usage	176	kt/year
District heating production	397	GWh
Infrastructure length (pipeline and electricity transmission)	70	km
Biomass price	25	EUR/MWh

3.4.3 Results of techno-economic assessment

Presents the resulting production costs for bioelectrofuels. The total cost for bioelectrofuels varies between 102-122 €/MWh fuel for the different cases under the base assumptions (according to Table 6) The largest share of the cost is attributed to hydrogen-related costs (48-57%). The lowest cost is achieved in Case 2, where the utilization of excess heat from the biofuel production in the form of district heating (DH) is assumed. Similar costs are observed in Cases 1 and 3.

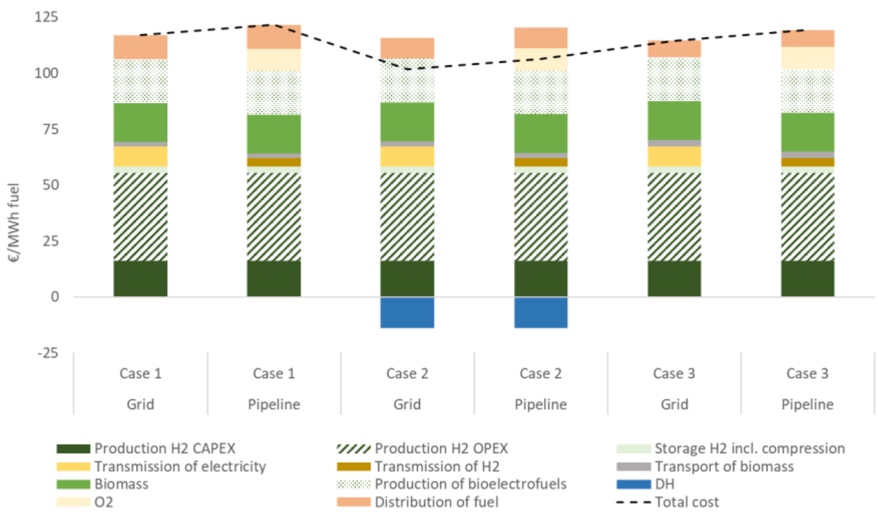

Figure 10. Production cost for bioelectrofuels with the three configurations presented: Case 1, fuel production is situated near the biomass resources, resulting in longer transportation distances to the end-users. Case 2, fuel production is co-located with a district heating system, allowing excess heat from the production process to be utilized for district heating. Case 3 fuel production is closer to the end-users, requiring longer transportation distances for the biomass feedstock. For both configurations, hydrogen production could be both on-site and off-site, where on-site hydrogen production requires electricity grid for energy transmission and off-site hydrogen production requires pipeline for hydrogen transmission – this is represented by grid or pipeline in the figure.

Regarding hydrogen/electricity distribution, distributing electricity via the grid and producing hydrogen at the bioelectrofuel production facility results in lower costs compared to distributing hydrogen to the production site via pipeline, assuming the same electricity price in both distribution cases. The primary reason for the lower cost of the grid option is that the oxygen demand for bioelectrofuel production is met by the oxygen produced from the electrolyser. In the pipeline distribution case, it is assumed that this oxygen must be produced separately (in an air separation unit, ASU), which adds an additional cost. Although the transmission cost[45] is higher for the grid option, the total cost is lower due to the offset of oxygen demand through the electrolyser. For the pipeline distribution to exhibit approximately the same total cost as grid distribution, the electricity price needs to be about 10% lower in the pipeline case than in the grid case.

The different cases show that bioelectrofuel production costs are primarily driven by hydrogen-related costs but are also strongly affected by the ability to utilize excess heat from fuel production. When excess heat from the fuel production process – about 397 GWh at high temperature levels – is considered, Case 2 can tolerate an electricity price nearly 40% higher than cases without heat recovery while maintaining the same total cost. If excess heat from the electrolyser is also utilized—an additional 264 GWh at a lower temperature—the acceptable electricity price difference increases to almost 50%, if the cases should achieve similar total costs.

[45] Pipeline: investment costs for the pipeline and hydrogen compression; Grid: investment costs related to the electricity grid and transformer station.

4 Socio-economic impact analysis

Decisions on hydrogen infrastructure are shaped by more than just technical and economic factors. Other socio-economic dimensions such as land availability, permitting complexity, public acceptance and regional planning constraints can determine whether electricity grids or hydrogen pipelines become the preferred solution. These aspects influence not only project costs but also timelines, feasibility, and societal impact.

Electricity transmission grids and hydrogen pipelines present distinct profiles. Power lines benefit from established regulatory frameworks and operational experience but frequently face resistance due to visual impact and land use conflicts. Hydrogen pipelines, though less visible, introduce new safety considerations and operate under evolving regulations. Regional conditions—such as industrial clustering, land fragmentation, and cumulative infrastructure impacts—further influence which option is most suitable.

To understand how these socio-economic factors influence infrastructure choices, this analysis combines literature review with nine stakeholder interviews. Representatives from permitting authorities, infrastructure developers, municipalities, and industrial actors provided insights into land and material use, permitting timelines and public acceptance in relation to hydrogen deployment.

The interviews were held with representatives from Länsstyrelsen Norrbotten, Energimarknadsinspektionen, Nordion Energi, Svenska Kraftnät, Uniper, Stegra, Liquid Wind, Stenungsunds municipality and Luleå municipality. Each discussion focused on the stakeholder’s specific role and expertise, providing context and insights on regulatory processes, spatial constraints and public acceptance.

Combining these insights with findings from the literature review offers a comprehensive view of how infrastructure choices between electricity grids and hydrogen pipelines can shape regional development and societal outcomes. This integrated perspective underscores the need to consider social acceptance and practical constraints alongside technical and economic factors when planning for hydrogen deployment.

4.1 LAND USE

New infrastructure requires land use, and the footprints created by electricity grid and hydrogen pipelines differs. Since the Swedish government has designated overhead lines as the main alternative for expanding the electricity grid at higher voltage levels[46], this is the assumption used in this study. For a 400 kV single-circuit overhead line, a corridor of approximately 45–50 meters is required, and for

[46] Klimat och näringslivsdepartementet, https://regeringen.se/pressmeddelanden/2025/01/regeringen-pekar-ut-luftledning-som-huvudalternativ-for-utbyggnad-av-elnat-pa-hogre-spanningsnivaer/, published 2025-01-31, used 2025-10-10

a double-circuit line, around 80–90 meters.[47] In forested areas, this results in a loss of productive land. Other effects may also occur, such as an increased risk of storm damage. When agricultural land is affected, it can generally continue to be cultivated under the power line, however it becomes more difficult to farm and harvest near pylons and anchoring wires.[48] Beyond the transmission line, additional infrastructure is required, including transformer stations, which also requires additional land use.

For hydrogen pipelines, there is a significant difference between the construction and operational phases. During construction, a work area of up to 50 meters may be required, and the ground needs to be excavated to install the pipeline. The depth of the trench is determined based on local conditions, where more exposed locations require deeper excavation to, for example, avoid frost damage. During operation, the corridor is reduced to approximately 10 meters to protect the pipeline from root intrusion. In the operational phase, it will be possible to use the land for cultivation. Depending on soil types, accessibility over the pipeline may not be restricted, even for heavy vehicles.[49] Apart from the pipeline, additional infrastructure, such as valve and compressor stations are required for the pipelines, which also requires additional land use.

When constructing new transmission lines or gas pipelines, landowners of the designated areas for the infrastructure will be affected by the use of their property. Two main laws regulate this; *Ledningsrättslagen (1973:1144)* governs the right to install and maintain infrastructure on private land without ownership transfer[50] and *Expropriationslagen (1972:719)* sets the framework for calculating compensation.[51]

When an actor applies for a network concession from The Swedish Energy Markets Inspectorate (Ei) to operate transmission lines or gas grids, they enter into land use agreements (*Markupplåtelseavtal*) with affected landowners. These agreements define the area of land granted for use and specify what the transmission line owner is permitted to do during construction, inspection and maintenance. They also clarify restrictions for the landowner, such as limitations on placing materials or conducting work near the line.[52,53] If no agreement is reached, concession application may apply for a statutory right of way (*ledningsrätt*) through Lantmäteriet.[54]

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[47] Svenska kraftnät, https://www.svk.se/om-kraftsystemet/om-transmissionsnatet/teknik/fragor-och-svar-teknik/faq-teknik/hur-bred-ar-ledningsgatan-for-luftledning-respektive-markkabel/, published 2025-03-26, used 2025-10-10

[48] Energimarknadsinspektionen, https://ei.se/bransch/koncessioner/ansokan-om-natkoncession-for-linje/jordbruk-och-skogsbruk, published 2024-05-14, used 2025-10-10

[49] Nordion Energi, https://nordionenergi.se/projekt/vatgasinfrastruktur/nordic-hydrogen-route/vatgasledning-skelleftea---umea/fragor-och-svar, published n.d, used 2025-10-10

[50] SFS 1973:1144. *Ledningsrättslag*

[51] SFS 1972:719. *Expropriationslag*

[52] Svenska kraftnät, https://www.svk.se/utveckling-av-kraftsystemet/transmissionsnatet/utbyggnadsprocessen/avtal/, published 2021-10-12, used 2025-10-10

[53] Nordion Energi, https://nordionenergi.se/projekt/vatgasinfrastruktur/nordic-hydrogen-route/vatgasledning-boden-skelleftea/fragor-och-svar, published n.d, used 2025-10-10

[54] Lantmäteriet, https://www.lantmateriet.se/sv/fastighet-och-mark/tillgang-till-annans-fastighet/Ledningsratt/, published n.d, used 2025-10-10

The landowner is entitled to compensation based on the market value of the affected property. Since a legal amendment in 2010, the law requires that this compensation includes a 25% premium on top of the market value or the reduction in value of the remaining property. This premium is intended to reflect the involuntary nature of the expropriation and to approximate what a landowner might expect in a voluntary sale.[55]

During the interviews it was mentioned that the compensation often is seen as too low by affected landowners. In 2023, the government launched an inquiry to review compensation for land use in connection with electricity grid expansion to increase the public acceptance and enable a faster and more efficient expansion of the electricity grid.[56] During the summer of 2024, a report was submitted to the ministry responsible, but no action has been taken.[57]

In addition to legal and financial considerations, several interviewees highlighted the physical limitations of available land as a growing challenge. In areas where multiple infrastructure projects converge—such as electricity grids, hydrogen pipelines, roads and housing developments—space becomes a scarce resource. As one stakeholder noted, there are some areas, like ports or industrial sites where new industrial activities are planned and all infrastructure needs to go to and from the same places—and sometimes there simply isn't enough room. These spatial constraints can lead to delays, rerouting or even cancellation of projects, especially when technical safety distances (e.g. between pipelines and electricity grids) must be maintained. How electricity and hydrogen infrastructure can be co-located is still under development, as safety distances and protective measures are required to ensure adequate operational and personal safety.[58] For example, current Swedish regulations specify a horizontal distance of 60 meters between a 400 kV power line and flammable materials[59], illustrating the scale of separation that may be needed when planning co-location of hydrogen pipelines and electricity grids. More information on technical risks and safety considerations for co-location can be found in this Energiforsk report[60].

4.2 MATERIAL USAGE

The main materials used in overhead transmission lines are steel and concrete, with steel typically used for towers and concrete for foundations. Conductors are usually uninsulated and primarily made of steel and aluminum. Transformers, another key component of the electricity grid, rely heavily on steel, copper, and oil. While overhead lines themselves are not the main bottleneck, transformers and

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[55] SFS 1972:719. *Expropriationslag*
[56] Klimat och näringslivsdepartementet, https://www.regeringen.se/pressmeddelanden/2023/08/ersattningen-for-upplatelse-av-mark-i-samband-med-elnatsutbyggnad-ses-over/, published 2023-08-25, used 2025-10-10
[57] Haider, https://data.riksdagen.se/fil/A5DF4E6F-9B00-4527-96D9-9F1DAA43F1DD, published 2025-03-18, used 2025-10-10
[58] Svenska Kraftnät, *Förslag till hur el- och vätgasinfrastruktur kan samplaneras i Norrbottens och Västerbottens län*, 2025
[59] ELSÄK-FS 2022:1, *Elsäkerhetsverkets föreskrifter och allmänna råd om hur starkströmsanläggningar ska vara utförda*, https://www.elsakerhetsverket.se/globalassets/foreskrifter/elsak-fs-2022-1.pdf
[60] Hugestam, S. et al., *Grovriskanalys av tekniska risker med samförläggning i ledningsgator,* Energiforsk, 2024

other critical components pose greater challenges. The expansion and modernization of power grids is not limited to Sweden, it is happening across Europe and globally, driving up demand for certain materials and making them strategically important.[61] This increased competition for resources can also lead to challenges in securing competitive bids for grid expansion and difficulties in finding qualified construction contractors.

Hydrogen pipelines require high-grade steel with enhanced resistance to embrittlement, fatigue and fracture due to hydrogen's impact on mechanical properties. This often involves using steels with controlled microstructures and hardness levels and potentially applying internal coatings or claddings to mitigate hydrogen interaction. Polymers can also be used in distribution pipelines with small diameters and used at low pressure.[62] The large expansion plans for hydrogen infrastructure, both in Sweden, Europe and globally coincides with a slowdown in natural gas grid development. This alignment allows parts of the existing supply chains to be redirected toward hydrogen, reducing the risk of bottlenecks in procurement and implementation.

4.3 PERMITTING PROCESSES AND TIMELINES

Developing electricity grid and hydrogen pipelines in Sweden involves a comprehensive permitting process. This section focuses on the permitting process for concession, but these large infrastructure projects are subject to multiple regulatory frameworks designed to safeguard environmental, cultural and societal interests. In addition to concession approval, further permits may be required under several frameworks, such as the Environmental Code *(Miljöbalken).* Depending on the project’s location and characteristics, other regulations, such as cultural heritage legislation *(Kulturmiljölagen)* or species protection dispensations *(Artskyddsförordningen)*, may also apply. For hydrogen pipelines, further requirements will apply, such as compliance with SEVESO regulations for hazardous substances as well as the act on Flammable and Explosive Goods (*Lag (2010:1011) om brandfarliga och explosive varor)*. Depending on the route of the transmission line or pipeline the process also includes municipal planning considerations, such as comprehensive plan (*Översiktsplan)* and detailed development plan (*Detaljplan)*.

The permitting process for concession for hydrogen pipelines is currently based on *Lag (1978:160) om vissa rörledningar*.[63] However, the regulatory landscape is changing. The EU hydrogen and gas decarbonisation package, adopted in 2024, updates the rules for the natural gas market and introduces a new regulatory framework for dedicated hydrogen infrastructure.[64] In Sweden, the Energy Markets Inspectorate has submitted a legislative proposal for a new Gas Market

[61] European Commissions: Joint Research Centre, Nohl et al. *Material requirements for electricity grids*, 2025

[62] European Commission: Joint Research Centre, Smedberg, E., et al., *Pipelines for hydrogen transport: A review of integrity and safety challenges,* 2025

[63] SFS 1978:160. *Lag om vissa rörledningar*

[64]European Commission, https://energy.ec.europa.eu/topics/markets-and-consumers/hydrogen-and-decarbonised-gas-market_en, published n.d, used 2025-10-07

Act[65], which will consolidate rules for natural gas, biogas and hydrogen and replace the current Natural Gas Act. The proposal is expected to enter into force on August 1st, 2026. Ei highlights two key consequences: a faster permitting process and clearer conditions for future hydrogen market participants.[66]

A central part of the proposal involves streamlining the permitting process for gas infrastructure. Ei suggests that concessions for new hydrogen pipelines should follow the same procedure as for electricity transmission grid, with Ei acting as the first-instance decision-maker instead of the government. Approved concessions would also be valid indefinitely, aligning gas infrastructure more closely with the electricity sector.[67] One difference remains in what requires a concession: for electricity grids, only the transmission lines are subject to concession, while associated facilities such as transformer stations and energy storage systems do not require separate approval. In contrast, for hydrogen pipelines, associated infrastructure, including metering and regulating stations, line valve stations, pigging stations, and compressor stations, must also be included in the concession application.

While hydrogen pipeline permitting is still evolving, electricity transmission follows an established process under the *Swedish Electricity Act (1997:857*). A high-voltage power line may not be constructed or used without a network concession, granted by the Swedish Energy Markets Inspectorate.[68] Before Ei can issue a permit, multiple interests must be considered, and everyone who may be affected by the power line must be given the opportunity to provide input during the permitting process.

Electricity transmission grid is always considered to have significant environmental impact under the Environmental Assessment Ordinance (*Miljöbedömnings-förordningen*), which makes scoping consultations and environmental impact assessment mandatory. Before the public consultation *(Samråd*) with landowners and other stakeholders, Svenska kraftnät conducts a dialogue with relevant authorities. This step involves gathering data and engaging with agencies, county administrations, municipalities and other actors affected by the planned transmission line. During this phase, alternative corridors are evaluated based on factors such as residential environment, constructability, natural and cultural values and municipal planning constraints. Based on this assessment, Svenska kraftnät selects one or more corridors to include in the next step, the public consultation.[69]

The public consultation focuses on proposed routing within the selected corridor. It is a legally required dialogue aimed at informing stakeholders and collecting important knowledge about the planned development. Property owners and

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[65] Energimarknadsinspektionen, *Vätgas i systemet – en gasmarknad i omställning – Genomförande av EU:s gasmarknadspaket*, Ei R2025:10, 2025

[66] Energimarknadsinspektionen, https://ei.se/om-oss/nyheter/2025/2025-06-19-ei-foreslar-en-ny-gasmarknadslag, published 2025-06-19, used 2025-10-07

[67] Energimarknadsinspektionen, https://ei.se/om-oss/nyheter/2025/2025-06-19-ei-foreslar-en-ny-gasmarknadslag, published 2025-06-19, used 2025-10-07

[68] SFS 1997:875, *Ellag*

[69] Svenska Kraftnät, https://www.svk.se/utveckling-av-kraftsystemet/transmissionsnatet/utbyggnadsprocessen/samrad/, published 2024-11-20, used 2025-10-07

nearby residents receive information about the project and have the opportunity to provide input or comments that are important for planning and determining the final route. Figure 11 illustrate the steps in the process.

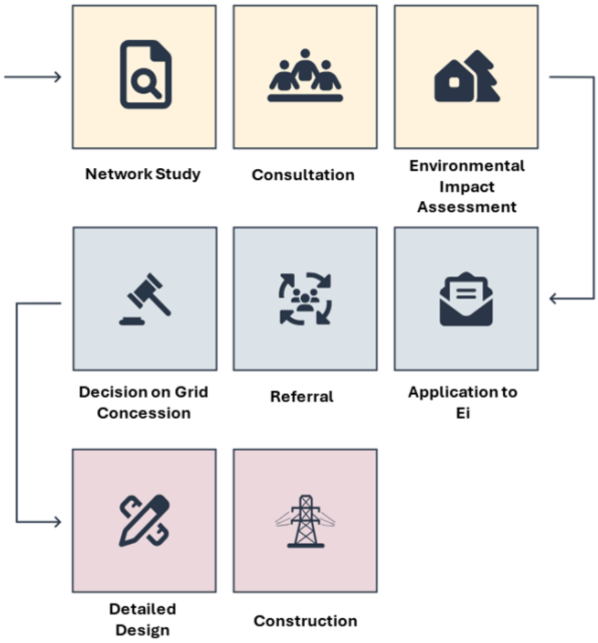

Figure 11. The permitting process for transmission lines, step by step[70].

When processing the concession application, Ei does not reassess components that have already been reviewed and approved through prior permitting processes, e.g. environmental permits. Instead, Ei incorporates those existing decisions into its assessment under the Electricity Act, while respecting the outcomes of previous proceedings under the Environmental Code.

The permitting process for transmission lines incorporates a socio-economic perspective. Under the Electricity Act (2 kap. 12 § ellagen), a line is considered suitable from a public standpoint if it meets criteria such as ensuring secure electricity supply, fulfilling EU obligations, or providing increased network capacity that is socio-economically profitable.[71] For projects involving expansion of the transmission grid, the application must also include an annex with a socio-economic profitability assessment.[72]

With Ei's proposed Gas Market Act, similar requirements will apply to hydrogen pipelines. The proposal specifies that a pipeline or facility should be deemed suitable if it is necessary to meet EU requirements, ensure a secure and efficient gas supply, provide socio-economically viable network capacity, or serve another

[70] Energimarknadsinspektionen, *Tillstånd för kraftledning.* https://ei.se/bransch/koncessioner/det-har-gor-ei-inom-koncessioner/tillstandsprocessen-for-kraftledning, published 2025-06-14, used 2025-10-06
[71] SFS 1997:875, *Ellag*
[72] Energimarknadsinspektionen, *Kostnadsberäkning och lönsamhetsbedömning,* https://ei.se/bransch/koncessioner/ansokan-om-natkoncession-for-linje/kostnadsberakning-och-lonsamhetsbedomning, published 2025-04-03 used 2025-11-14

important public interest.[73] Applications for hydrogen pipelines will also need to include a socio-economic profitability assessment[74], which is already a requirement for electricity grid concessions for transmission grids[75].

Although the legal basis differs between electricity grids and hydrogen pipelines, the permitting steps are largely similar. However, the number of cases varies significantly—there are currently over 60 ongoing electricity grid permitting processes, while no hydrogen pipeline cases have yet been submitted to Ei. This lack of historic activity in Sweden makes direct comparison challenging, as there is statistical data available for electricity grids but not for hydrogen pipelines.

The permitting lead time at the Swedish Energy Markets Inspectorate—from case registration to decision—has been the focus of improvement efforts. Initiatives include the development of e-service for grid concession applications, cross-functional teams, enhanced dialogue with grid companies, and parallel processing of decision writing and referrals. The estimated lead time of 9–24 months still applies, but 2024 data showing a range of 7–21 months reflects progress toward faster permitting.[76]

The total process time for transmission grid projects from initial investigation to commissioning has improved in recent years. Earlier estimates ranged from 7 to 15 years, but data shows a nearly 30% reduction, with the average time dropping from 10.5 to 7.5 years.[77] Nordion estimates the overall process time for hydrogen pipelines to around 6 years for the project that has PCI status.

4.4 PUBLIC ACCEPTANCE AND STAKEHOLDER ENGAGEMENT

Public acceptance and stakeholder engagement are critical factors in energy infrastructure development. While overall support for the energy transition among European citizens is high, local opposition to specific projects remains common.[78] Such opposition can stem from mismatches with place-related identities, concerns about visual impacts, electromagnetic fields (EMF) and perceived risks to health and biodiversity.[79,80] In Sweden, public consultations often reveal worries about EMF exposure, landscape changes and restrictions on land use. These concerns are compounded by limited research on cultural landscape impacts, while scientific studies consistently indicate that health risks from EMF are very low, yet public apprehension persists.[81]

[73] Energimarknadsinspektionen, *Vätgas i systemet – en gasmarknad i omställning – Genomförande av EU:s gasmarknadspaket,* Ei R2025:10, 2025

[74] Energimarknadsinspektionen, *Vätgas i systemet – en gasmarknad i omställning – Genomförande av EU:s gasmarknadspaket,* Ei R2025:10, 2025

[75] Energimarknadsinspektionen, *Tillstånd för kraftledning.* https://ei.se/bransch/koncessioner/det-har-gor-ei-inom-koncessioner/tillstandsprocessen-for-kraftledning, published 2025-06-14, used 2025-10-06

[76] Sonder, *Uppföljning av ledtider för utbyggnad av region och transmissionsnät,* 2024.

[77] Sonder, *Uppföljning av ledtider för utbyggnad av region och transmissionsnät,* 2024.

[78] IEECP, *Drivers and barriers of public engagement in energy infrastructure*, 2023.

[79] IEECP, *Drivers and barriers of public engagement in energy infrastructure*, 2023.

[80] Helldin, J. O, Kågström, M., *Miljöeffekter av elnät – en förstudie*, 2023.

[81] Helldin, J. O, Kågström, M., *Miljöeffekter av elnät – en förstudie*, 2023.

Geographical context also influences acceptance: in southern Sweden, fragmented land ownership and intensive land use increase the likelihood of opposition and prolong permitting processes, whereas northern Sweden's large forested areas with fewer institutional landowners tend to present less resistance.[82] One interviewed stakeholder emphasized that resistance is often strongest where land fragmentation is high and visual impacts are significant, noting that people generally support the energy transition but do not want infrastructure close to their homes or land.

International studies confirm that overhead transmission lines often face resistance due to visual intrusion and EMF concerns, while underground hydrogen pipelines, being less visible, may encounter fewer aesthetic objections, though they raise other safety and environmental issues.[83,84] Several interviewees highlighted that hydrogen pipelines introduce new uncertainties, and as people tend to fear the unknown, hydrogen feels unfamiliar and risky. Therefore, companies need to show robust risk analyses and clear safety measures. Another interviewee stressed that early, respectful dialogue is essential. If a hydrogen pipeline is planned near homes, industry must engage early and openly to build trust.

Meaningful public engagement goes beyond acceptance-building; it enables communities to voice concerns, improves decision legitimacy and fosters trust between developers and stakeholders.[85] Barriers include lack of awareness, insufficient trust and inadequate institutional capacity to design participatory processes.[86] Interviewees echoed these findings, noting that early dialogue can help mitigate concerns, in some cases, the only way to achieve public acceptance is to reroute the line. Others highlighted that economic arguments could influence attitudes; when people understand that electricity or hydrogen supply supports local jobs, they tend to be more receptive to infrastructure development.

Addressing these challenges requires early dialogue, recognition of local values and transparent communication about both risks and benefits, including potential ecological and recreational opportunities associated with transmission corridors.[87] Interviewees also stressed the importance of balancing competing interests; routing decisions often involve trade-offs between energy needs and protecting nature, cultural heritage, or livelihoods like reindeer herding, agriculture and forestry.

In this context, some stakeholders emphasized the importance of considering the cumulative effects of infrastructure development. While individual projects may appear manageable in isolation, the combined impact of multiple energy infrastructures — such as power lines at various voltage levels, hydrogen pipelines and associated facilities — can significantly alter landscapes and ecosystems over time. As noted in recent research, the relevant environmental and social impacts often arise not from a single line or station, but from the aggregated presence of

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[82] Sonder, *Uppföljning av ledtider för utbyggnad av region och transmissionsnät*, 2024.
[83] Neumann, F. et al. *The potential role of hydrogen network in Europe*, Joule, Vol 7, 2023. https://doi.org/10.1016/j.joule.2023.06.016
[84] Patonia, A. et al., *Hydrogen pipelines vs. HVDC lines: Should we transfer green molecules or electrons?*, 2023, OIES Paper: ET, No. 27, ISBN 978-1-78467-221-8
[85] IEECP, *Drivers and barriers of public engagement in energy infrastructure*, 2023.
[86] IEECP, *Drivers and barriers of public engagement in energy infrastructure*. 2023.
[87] Helldin, J. O, Kågström, M., *Miljöeffekter av elnät – en förstudie*, 2023.

infrastructure across regions. Despite this, there is a lack of comprehensive research on how these cumulative effects influence public perception, biodiversity and land use over time.[88] Recognizing and addressing these cumulative effects is essential for maintaining public trust and ensuring that infrastructure development aligns with broader sustainability and energy transition goals.

4.5 RESILIENCE AND SYSTEM ROBUSTNESS

Investments in energy transmission infrastructure are inherently costly and long-term, which underscores the importance of ensuring that these investments meet system needs in a cost-effective manner. In addition, the heightened geopolitical risk following Russia's full-scale invasion of Ukraine in 2022 has reinforced the need to incorporate preparedness and total defense considerations into infrastructure planning. This is essential to guarantee that society's critical functions can maintain energy supply during crises or wartime conditions.[89]

From a resilience perspective, electricity grids and hydrogen networks offer complementary advantages. Electricity transmission infrastructure benefits from a broad user base and diverse applications, making it easier for a single line to serve multiple purposes compared to a hydrogen pipeline.[90] Conversely, hydrogen infrastructure provides superior storage capability, which can enhance system robustness and facilitate greater integration of intermittent renewable generation.[91,92] Establishing a large-scale hydrogen system as a complement to the national electricity grid would increase the ability to sustain operations during prolonged disruptions in either system. However, this requires significant adaptation and investment by energy users, such as hydrogen-fueled gas turbines or local electrolysers for critical hydrogen production during external supply interruptions. Central measures, including strategic gas storage and import capacity, would also be necessary.[93]

Interviewees stressed that having two large-scale transmission systems—electricity and hydrogen—would significantly improve overall system robustness. It should be noted, however, that hydrogen pipelines rely on compressor stations powered by electricity, which means the hydrogen network is not fully independent and remains partly dependent on the electricity system. In the future, this could change as technical solutions and regulatory frameworks evolve. Gas-driven compressors are already a proven concept in natural gas systems worldwide, and development is underway for hydrogen applications, including turbines for 100% hydrogen operation. However, standards and permitting processes are still incomplete, and

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[88] Helldin, J. O, Kågström, M., *Miljöeffekter av elnät – en förstudie*, 2023.
[89] Svenska Kraftnät, *Förslag till hur el- och vätgasinfrastruktur kan samplaneras i Norrbottens och Västerbottens län*, 2025.
[90] Svenska Kraftnät, *Förslag till hur el- och vätgasinfrastruktur kan samplaneras i Norrbottens och Västerbottens län*, 2025.
[91] Svenska Kraftnät, *Förslag till hur el- och vätgasinfrastruktur kan samplaneras i Norrbottens och Västerbottens län*, 2025.
[92] Patonia, A. et al., *Hydrogen pipelines vs. HVDC lines: Should we transfer green molecules or electrons?,* 2023. OIES Paper: ET, No. 27, ISBN 978-1-78467-221-8
[93] Svenska Kraftnät, *Förslag till hur el- och vätgasinfrastruktur kan samplaneras i Norrbottens och Västerbottens län*, 2025.

widespread implementation will require further technological progress and regulatory alignment.

Hydrogen infrastructure is increasingly recognized as a strategic enabler for resilience, supporting sector coupling across industry, transport and power. This multi-vector approach reduces vulnerability to single-point failures and strengthens energy security by diversifying energy carriers beyond electricity-only transmission.[94,95] Furthermore, hydrogen pipelines offer large-scale transport and seasonal storage capabilities, which electricity grids cannot provide, making them particularly valuable for balancing supply during extended renewable energy droughts or crisis scenarios.[96] Interviewees noted that hydrogen could also serve as an alternative to diesel generators for backup power in critical facilities such as hospitals, aligning with long-term decarbonization goals.

Dimensioning criteria also play a critical role in defining system robustness. Svenska kraftnät applies the N-1 criterion, which requires the power system to withstand any single contingency, such as the loss of a transmission line or generation unit. While this establishes a fundamental level of resilience, achieving robustness against rare but high-impact events requires complementary measures beyond N-1, implemented where they are technically and economically justified.[97]

Infrastructure planning must also account for geopolitical risks, sabotage and natural disasters. Hydrogen pipelines may be more difficult to repair quickly after damage, emphasizing the need for redundancy and fallback mechanisms.[98] Interviewees highlighted the importance of designing infrastructure to withstand climate-related hazards such as flooding, landslides and extreme storms, and noted that physical robustness—such as burying pipelines—can reduce exposure to certain risks. They also raised concerns about geotechnical risks like landslides and the need for adaptations to future conditions, including increased precipitation and stronger storms.

Finally, domestic fuel production emerged as a distinct resilience benefit. Interviewees emphasized that enabling local hydrogen production through electrolysers reduces reliance on imports and strengthens autonomy in energy supply, regardless of whether the primary infrastructure is electricity or hydrogen. This capability is viewed as essential for maintaining critical operations during prolonged disruptions and for supporting future synthetic fuel production for transport.

4.6 LOCALISATION ASPECTS

Stakeholder insights highlight that electricity infrastructure is the single most decisive factor for site selection. A secure and timely grid connection is viewed as

[94] European Hydrogen Backbone, *Implementation Roadmap: Cross-Border Projects and Costs Update*, 2023.

[95] Patonia, A. et al., *Hydrogen pipelines vs. HVDC lines: Should we transfer green molecules or electrons?*, 2023. OIES Paper: ET, No. 27, ISBN 978-1-78467-221-8

[96] Patonia, A. et al., *Hydrogen pipelines vs. HVDC lines: Should we transfer green molecules or electrons?*, 2023. OIES Paper: ET, No. 27, ISBN 978-1-78467-221-8

[97] Svenska Kraftnät, *Driftsäkerhet I kraftsystemet – framtidens behov och förmågor*, 2025.

[98] Patonia, A. et al., *Hydrogen pipelines vs. HVDC lines: Should we transfer green molecules or electrons?*, 2023. OIES Paper: ET, No. 27, ISBN 978-1-78467-221-8

critical from both a risk management and operational perspective. Large-scale hydrogen projects require substantial and continuous access to renewable electricity at competitive prices, ideally with baseload capacity to ensure high uptime and low operating costs. Regions such as SE1, SE2, and NO4 are considered particularly attractive due to low electricity prices and high shares of low-carbon generation, aligning with RFNBO requirements.

While discussions around hydrogen pipeline infrastructure are prevalent, stakeholders have highlighted the current absence of it, which in turn includes uncertainty. Stakeholders have hence opted to co-locate electrolysers with offtake points to ensure implementation of their projects, although a hydrogen pipeline could be of interest when realized. Instead, electricity availability and predictable permitting processes for grid connections dominate decision-making today. Stakeholders expressed a strong need for more transparent and efficient dialogue with grid operators to reduce uncertainty and delays.

Beyond electricity, proximity to supporting infrastructure—such as ports, railways, and raw materials—plays an important role. For electrofuel production, co-location with a CO_2 source is particularly critical since CO_2 is a key input and transporting large volumes over long distances is costly. For hydrogen-based steel production, the priority when finding a new localization in Sweden has been to consolidate the entire value chain—such as hydrogen production, direct reduction, and steelmaking—within a single site. This integrated approach enables better heat balance, minimizes repeated heating cycles, and creates opportunities for digital optimization and scalability.

The potential to utilize by-products such as oxygen and residual heat is generally seen as a bonus rather than a primary driver. While industrial symbiosis and district heating integration can strengthen the business case, these factors are highly dependent on local conditions and timing. Electricity price and power availability remain far more influential than by-product utilization.

Securing grid connections for large-scale electrolyser projects is more complex and time-consuming than for smaller facilities. In Sweden, industrial loads above ~400 MW typically require transmission-level connections, often involving new substations or reinforcements, which adds cost and delays.[99] Growing grid connection queues across the Nordics and lengthy permitting processes further exacerbate these challenges.[100,101] This dynamic suggests that decentralized hydrogen production using smaller, strategically located electrolysers may enable faster deployment by leveraging existing regional grid capacity. While decentralization may sacrifice some economies of scale, its ability to shorten timelines could deliver earlier socio-economic benefits compared to centralized, large-scale projects awaiting major grid upgrades.

[99] Beyond Fossil Fuels, *How Europe's grid operators are preparing for the energy transition,* 2025

[100] Holmberg, P., Tangerås, T., *The Swedish electricity market – today and in the future.* SVERIGES RIKSBANK ECONOMIC REVIEW, Volume 1. 2023.

[101] Nordic TSOs, *Nordic Grid Development Perspective*. 2025

5 Energy systems modelling

In addition to the technoeconomic and socioeconomic analysis that has been presented, a second-stage system-level analysis could serve as a complementary effort to provide a higher-level picture for strategic decision-making. While a full system-level analysis could not be conducted within the scope of this project, this chapter instead outlines the prerequisites for such an analysis and presents an example of the type of results that could emerge from it.

It should be emphasized that the results presented in this chapter are a demonstrative case. It does not directly correspond to, nor should it be interpreted as a continuation of, the specific cases illustrated earlier in the report. The purpose of the chapter is to showcase the modelling framework and the results possible from this type of analysis.

Comparing centralized and distributed hydrogen production involves a complex analysis of interconnected, time-dependent factors. A key challenge is that each component of the hydrogen supply chain—from production to delivery—faces different and often long construction timelines, creating potential bottlenecks. These delays create cascading effects on investment behavior. For example, a centralized hydrogen plant may be ready for operation if pipeline connections or storage facilities are available. Similarly, onsite production depends on reliable power grid connections and local storage solutions that may face their own construction challenges.

The complexity deepens when considering demand patterns across different sectors and their aggregated impacts on the supply side. Plant sizes and utilization factors may vary between onsite installations and centralized facilities. These differences in scale and utilization create distinct economic and operational dynamics that ripple through the entire system.

A system-level analysis can examine how construction delays, investment timing, infrastructure dependencies, demand patterns, and economies of scale interact at the national level over time.

5.1 APPROACH

The hydrogen module of RISE national energy systems model (RISE NESM) is developed to simulate the continual transition towards hydrogen system as markets dynamically adjust to changes in supply and demand. The model is based on systems dynamics approach, integrating supply, demand, and market to evaluate the feedback effects and dynamic behaviors governing the hydrogen transition. Figure 12 visualize the simplified key feedback mechanisms and inter-sectoral relationships withing the hydrogen module's conceptual framework.

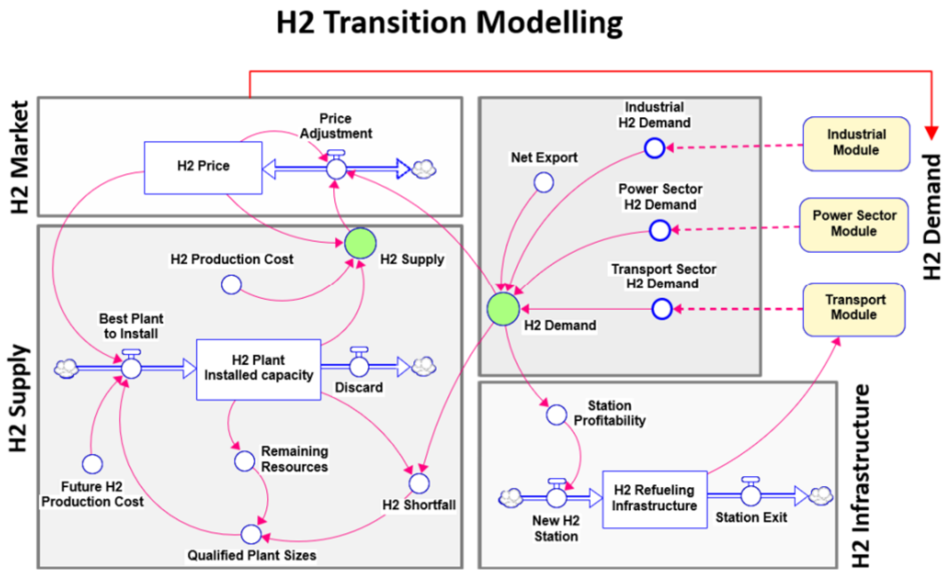

Figure 12. Feedback loops and sectoral relationships in the hydrogen module of RISE national energy systems model.

Through the system dynamics approach it is possible to explicitly model factors such as supply-demand buffers, infrastructure delays, and systemic inertia. This includes how hydrogen storage can balance fluctuations, and how delays in deployment and adoption affect transition timelines. Feedback loops, for instance how incentives for implementation of large-scale plants drives supply cost and influences future investment decisions and market growth, are also captured, helping identify leverage points and avoid unintended effects such as policy resistance. Below is a brief explanation of each subsystem in the hydrogen module.

5.1.1 Hydrogen Supply

The supply side of the hydrogen module is defined by its production capacity and resource allocation. This involves tracking the current capacity of plants (production and storage) and determining the most profitable technologies and plant sizes for new installations. Future costs and prices are influenced by economies of scale and technology development, while expansion is limited by resource availability and infrastructure bottleneck. The entire supply chain must deliver a consistent flow of hydrogen to meet demand along with economic viability triggering investments to increase production.

5.1.2 Hydrogen Demand

The model includes hydrogen demand from key sectors including: steel, chemicals, e-fuels, transport, and power. These demands are combined to create total hydrogen demand, which affects production decisions, costs, and infrastructure planning. For this analysis, an example of demand for selected sectors is assumed as exogenous input (see Figure 13) since we use the H2 module of the RISE NESM.

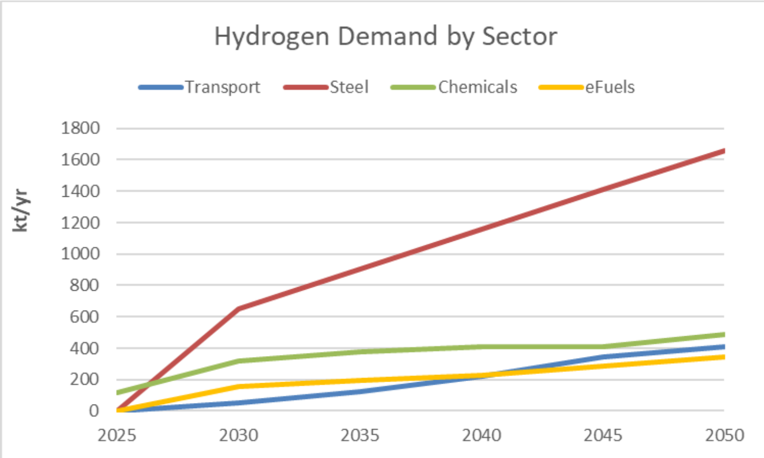

Figure 13. Assumed hydrogen demand at the national level over time for Sweden (data were adapted from baseline scenarios in Fagerström. A. et.al 2024[102] with simplification and modification.

5.1.3 Hydrogen Market

The hydrogen market determines the long-term price of hydrogen, which can be set by either production cost or the balance of supply and demand. As the price changes, it directly influences the demand for hydrogen (under endogenous mode) and, in a feedback loop, impacts production decisions and capacity planning.

5.2 BOUNDARIES AND SCOPE OF ANALYSIS

The model adopts a holistic, system-level approach to analyze the complexity of energy systems. The focus of the model is on understanding the co-evolution and interrelationships among various sub-systems over time. The scope of the current analysis is limited to hydrogen sector.

5.2.1 Spatial Resolution

The model presented in this report takes an aggregated approach, focusing on national-level data to capture broad trends in hydrogen supply and demand. While the model does not account for localized variations in energy demand, it provides a high-level perspective on the drivers and barriers of hydrogen transition. To gain an understanding of where hydrogen plants would be built, the hydrogen sector (in a multi-regional case) is regionalised by the same regions as the electricity sector on the supply-side (SE1, SE2, SE3, and SE4). As electricity prices vary by region in a multi-regional model, those variations will impact the placement of hydrogen facilities. These regions differ in electricity costs due to variations in energy resources, population density, limited transmission capacity, and industrial activity.

[102] Fagerström, A. et al., *The potential of Hydrogen in a Swedish Context*, Energiforskrapport, 2024:1011, 2024

5.2.2 Temporal Resolution

The analysis focuses on a long-term horizon, with projections and analysis extending to 2050. This is particularly relevant for strategic planning, climate targets, and long-term energy transition scenarios. The temporal's flexibility allows for the incorporation of diurnal and seasonal variations, to properly capture the impact of changes in energy flows as well as construction time delays. For the current analysis, as demand is exogenous, the simulation timestep is set to monthly intervals from 2025 to 2050 (to properly capture construction delays for projects with sub-annual completion times, such as modular electrolyser stack expansions).

5.2.3 Electrolyser Technologies and Plant Setups

Electrolysers are central to converting the supplied electricity into hydrogen. In the current version of the model, two key technologies for electrolysis are identified:

- Alkaline Electrolysis (AEC): A mature technology, operating efficiently with stable electricity input, making it well-suited for plants powered by grid electricity.
- Proton Exchange Membrane Electrolysis (PEM): A more advanced technology offers greater flexibility and can respond quickly to fluctuating renewable energy inputs, although it is generally more expensive than AEC.

The model also highlights two possible plant setups:

- Onsite Plants: Located close to demand centers, minimizing hydrogen transportation costs but require adequate electricity transmission capacity.
- Centralized Plants: Typically situated in areas with abundant grid electricity or renewable resources. They rely on a pipeline network to distribute hydrogen to different end-users.

5.3 KEY ASSUMPTIONS

The model requires a set of input data to simulate the complex interactions between various factors influencing hydrogen transition. These input data categories encompass a wide range of parameters critical for model accuracy and reliability. Key input data include:

- Techno-economic characteristics of hydrogen technologies:
    - Production: Capital costs, operating costs (fixed and variable), efficiencies (e.g., electrolyser efficiency), and the impact of learning and economy of scale on production costs, feasible plant sizes, and construction time.
    - By-products: amount of oxygen, recoverable heat and their respective costs/values.
    - Storage: Capital costs, operating costs, storage capacity, storage losses, and construction time.

  - Hydrogen pipeline and electricity grid: Capital costs, operating costs, transportation losses, and typical construction time.
- Economic, behavioral, and socio-political factors:
  - Subsidies and taxes: Government policies that can significantly impact the economics of hydrogen production, distribution and use, such as subsidies for renewable energy, energy taxes, incentives.
  - Regulatory and permitting timelines: processes that influence project implementation, including construction, operational permit processing, and integration timelines (e.g. grid connection). These delays can significantly impact projects financing cost, investment decisions and deployment rates.
  - Behavioral and market dynamics: Investor risk perceptions

5.4 RESULTS – ILLUSTRATIVE EXAMPLE FOR NATIONAL-LEVEL SIMULATION OF HYDROGEN CAPACITY EXPANSION

The illustrative example results are presented at aggregated national level, representing the combined evolution of capacities across all hydrogen demand sectors—including steelmaking, chemicals, e-fuel production and transport—and across Sweden's multiple electricity bidding areas. This system-level experiment captures national-scale interactions between supply, infrastructure, and demand rather than focusing on specific industrial sites or regions.

Figure 14 presents a simplified example results from RISE national system dynamics model simulating long-term capacity expansion in Sweden's hydrogen supply chain. Two simplified onsite and offsite configurations are compared, each designed to meet 50% of national hydrogen demand for an illustrative test case comparison. The observed investment cycles reflect the combined effects of construction times, market expectations, and different investment decision mechanisms between onsite and offsite systems.

For the onsite configuration in this example, investment decisions are assumed to be demand- and cost-driven, responding directly to local hydrogen needs and focusing on the least-cost viable technological options. In contrast, centralized offsite plants are modelled as profitability-driven, with investors making decisions based on expected long-term market returns. Larger centralized projects typically require longer construction time and involve more complex permitting processes (although the latter is not explicitly considered in this example). Profitability expectations and perceptions of market risk can change over time, leading investors to postpone or change the scale of investment, which introduces additional delays and could lead to the cyclical investment behavior observed in this specific test case.

For example, technical, economic, and behavioral factors interact to produce cyclical construction patterns in offsite plants: greenfield new plant investment surges during certain periods, followed by modular stack expansion phases as the newly built capacity becomes operational. New plants are assumed facing longer construction and approval times than modular stack expansions at existing sites, which can be completed more rapidly using established infrastructure.

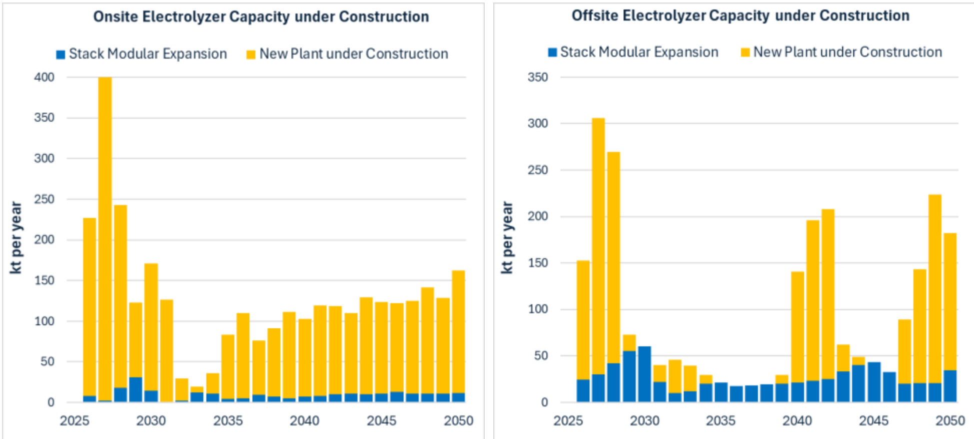

Figure 14. Comparison of capacity under construction for onsite and offsite electrolyser configurations.

Figure 15 compares three capacity metrics for onsite and offsite hydrogen plants: expected capacity (installed plus under construction), installed capacity (construction complete), and operational capacity (in service). The gap between expected capacity (red curve) and installed capacity (solid blue curve) represents capacity that is still under construction or in the commissioning phase—comprising both new greenfield projects and modular stack expansions as illustrated in Figure 14 above. The presented cconstruction delays are aggregated across plant sizes, ranging from one year (10 MW) to three years (700 MW) for new plants, and less than one year for modular stack additions.

While total installed capacity increases steadily, operational capacity may lag due to infrastructure readiness bottlenecks, i.e. limited pipeline capacity for offsite plants and electricity grid constraints for onsite configurations. These delays cause underutilization of deployed capacity, where capacity exists but is not yet fully productive, potentially leading to higher transition costs.

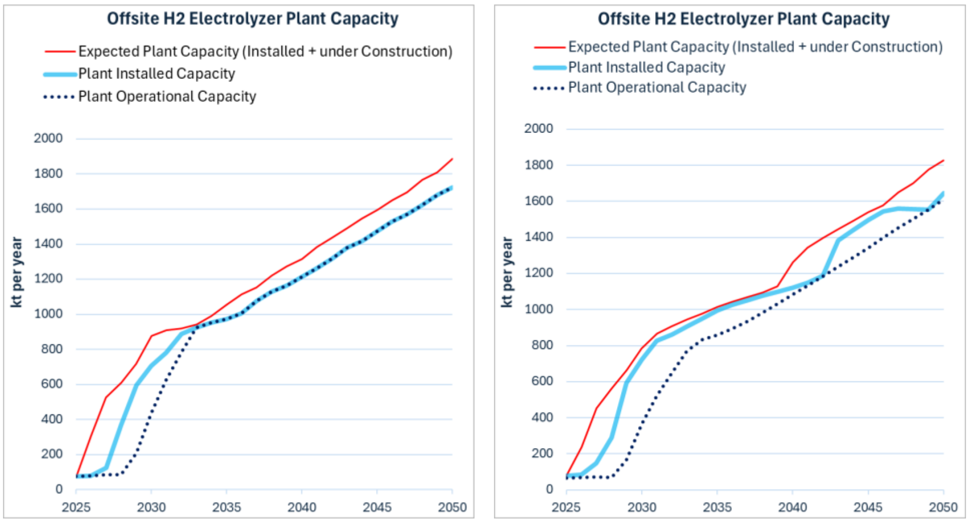

Figure 15. Dynamic capacity evolution showing three stages of hydrogen capacity development: expected capacity (available plus planned projects), installed capacity (construction complete), and operational capacity (in production). Time lags between curves represent cumulative delays through construction, commissioning, and operational start-up (note: permitting time lag is not included in this simulation).

Figure 16 shows a simplified example of how the corresponding power transmission (onsite) and hydrogen pipeline capacity (offsite) evolve over time. In both cases, expected expansion (red line) exceeds realized installation (blue line), showing the assumed lags behind capacity construction and commissioning (dashed green line).

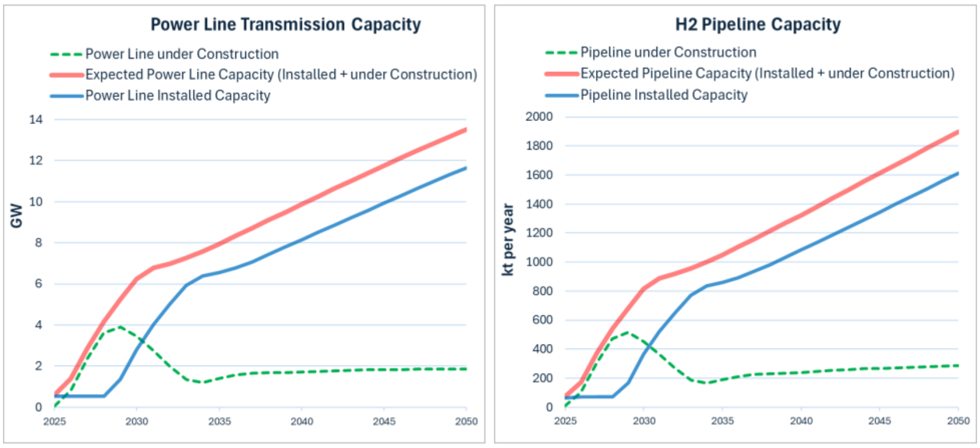

Figure 16. Infrastructure capacity trajectories showing the gap between expected expansion (dashed red) and realized installation (solid blue) for power transmission (left) and hydrogen pipelines (right), demonstrating construction and commissioning delays

In summary, the combined effects of phased capital planning (driven by longer construction times) and asynchronous commissioning of interconnected infrastructure can increase system development costs and extend payback periods. While larger centralized plants benefit from economies of scale, their longer construction and integration timelines—combined with dependence on efficient byproduct utilization (e.g. heat recovery)—may partially diminish these advantages. Therefore, plant sizing and scaling decisions must be carefully evaluated through an extensive simulation-based comparative analysis under various scenarios that capture demand growth patterns, permission and construction delays, resource constraints, infrastructure readiness, centralized storage needs, and byproduct utilization potential. Such analysis is essential to identify the most efficient transition pathways from a national perspective. Furthermore, since infrastructure projects potentially face long lead times (and socio-political challenges), simulation of various capital phase planning and investment sequencing under different scenarios are important to understand the system-level implications under evolving and uncertain market conditions (see section 5.5 for capacity expansion strategies).

While the system dynamics simulation model aggregates the sectoral and regional dynamics for national policy analysis, the same analytical framework can be adapted for sector-specific studies, for instance, to assess hydrogen deployment exclusively for steel production or e-fuel production—within a broader system context. The approach can also be applied to localized case studies at the plant or regional level. However, such applications would focus on project-specific optimization or regional logistics rather than the systemic interdependencies and feedback mechanisms that emerge at the national scale.

5.5 TACKLING INDUSTRY RISKS AND THE “CHICKEN-OR-EGG” PROBLEM – POSSIBLE ANALYSIS

The modelling framework offers several approaches to comprehensively assess the economic viability of expanding hydrogen production capacity. It can address the well-known "chicken-and-egg" dilemma where limited infrastructure discourages demand, and low demand hinders infrastructure development. Different capacity expansion strategies can be considered, each with distinct characteristics and implications for risk management and market development.

- **Reactive Demand-Pull**: Capacity is expanded in response to observed or anticipated demand growth. This conservative approach minimizes financial risk and avoids overcapacity but may result in supply shortages if demand increases rapidly or unpredictably. It can follow either market-wide expansion or sector-specific demand targeting.
- **Proactive Supply-Push**: Initial investments are made to stimulate demand by securing hydrogen availability. This strategy aims to overcome early adoption barriers and create positive feedback loops, but it carries the risk of overcapacity if demand does not materialize as expected.
- **Proactive Capacity-Leading**: Capacity is expanded ahead of demand based on optimistic forecasts. This approach prioritizes flexibility and resilience, enabling rapid adoption and long-term cost efficiencies through economies of scale. However, it requires higher upfront investment and may lead to underutilized assets in the short term.

- **Target-Driven**: Capacity expansion is guided by predefined policy or regulatory targets, such as carbon neutrality or energy security. While this approach ensures alignment with societal goals, it may introduce inefficiencies if targets are misaligned with actual market readiness or demand.
- **Balanced Feedback-Driven**: This strategy combines elements of both reactive and proactive approaches mentioned above, dynamically adjusting capacity expansion based on continuous monitoring of market trends, policy developments, and technological progress. It aims to balance risks by scaling infrastructure in response to evolving conditions.

6 Discussion and conclusions

The transition to fossil-free fuels and industrial processes requires not only technological innovation but also strategic choices about infrastructure. Electricity grids and hydrogen pipelines represent two critical enablers of this transformation, yet their roles, benefits and limitations vary depending on context. This chapter synthesizes insights from the techno-economic analysis and stakeholder perspectives to explore how these infrastructures interact with industrial value chains, system-level resilience, and socio-economic factors. It also examines practical considerations such as permitting, localization and public acceptance, highlighting why infrastructure decisions from a socio-economic perspective cannot be made in isolation but must balance cost efficiency, feasibility, and long-term sustainability.

The technoeconomic analysis covered three industrial value chains—fossil-free steel, electrofuels, and bioelectrofuels— under different configurations of fuel production (centralized and decentralized) and hydrogen production (on-site versus off-site). In these configurations, electricity grids were assumed for on-site hydrogen production, while hydrogen pipelines were considered for off-site production. Based on this techno-economic analysis, there is no universal advantage for either electricity grids or hydrogen pipelines; the optimal configuration depends on local conditions, integration opportunities and scale. For example, co-location of hydrogen and fuel production in bioelectrofuel systems improves cost efficiency due to oxygen utilization, favoring electricity grid solutions. Similarly, proximity to low-cost electricity and access to CO_2 for synthesis are decisive factors for localization.

For electrofuels, production costs range between 142–161 €/MWh, with hydrogen-related expenses dominating the cost structure (67–79%). The lowest cost occurs in decentralized configurations where electricity is distributed via the grid and oxygen from the electrolyser can be utilized in the CHP process. When oxygen demand is absent, centralized and decentralized configurations show similar costs, and the choice between grid and pipeline distribution becomes less significant. However, if oxygen demand exists, pipeline distribution would require a lower electricity price to match the cost of grid-based production.

For bioelectrofuels, production costs vary between 102–122 €/MWh, with hydrogen-related costs accounting for around half of the total (48-57%). The most cost-effective configuration is achieved when excess heat from fuel production can be utilized for district heating, highlighting the importance of integration opportunities. Distributing electricity via the grid and producing hydrogen on-site generally results in lower costs than pipeline distribution, primarily because the electrolyser's oxygen by-product meets the facility's oxygen demand. In configurations where excess heat from fuel production can be utilized, the total cost advantage is significant enough that electricity prices may be up to 40% higher compared to cases without heat recovery, while still achieving similar overall cost levels.

For steel production, the production costs vary between 465.7 – 546.4 €/tCS, with hydrogen-related costs accounting for c. 41 - 46%. The base cases show minimal differences between the value chain configurations, mainly as transportation costs account for minor shares of the LCOP. The LCOP is however shown to be slightly lower in the pipeline scenario. The potential use volumes of residual oxygen in the EAF are small, resulting in minimal cost-benefits of co-locating the electrolyser with the steel plant. As residual by-products from the electrolyser are in significantly large scale, the potential external offtake can be challenging. The analysis show that 10% external offtake of waste heat (96 GWh) and oxygen (64 kt) decreases the production cost by c. 4 €/tCS. Hence, on- or offsite location of the electrolyser is shown to have minimal economic impact on the steel production cost. Rather, the LCOP shows sensitivity to electricity prices, indicating that electricity costs are the primary factor to consider from a techno-economic perspective.

Overall, these results emphasize that infrastructure choices cannot be evaluated in isolation. Factors such as co-location benefits, integration of by-products and regional electricity price differences strongly influence competitiveness. While grid-based solutions tend to be more favourable in scenarios with oxygen demand or heat recovery potential, hydrogen pipelines may become advantageous at very large energy transfer scales or where electricity grid expansion faces constraints. Similar benefits could also be achieved if by-products could be utilized at alternative locations, which adds flexibility to system design and can further improve overall efficiency.

The possibility of utilizing by-products from hydrogen production does not have to be tied to the choice of infrastructure. However, given the scale of by-product volumes in the value chains analysed, it appears more likely that oxygen can be utilized when it is directly integrated into the production process. This was also confirmed in interviews: if companies cannot use the by-products themselves, practical aspects such as timing of investment decisions between different actors become critical to ensure that oxygen is available when needed by a nearby user. Alternatively, hydrogen production may need to be located where there is already significant oxygen demand. Actors emphasized that when they cannot use the by-products internally, this is seen only as an additional benefit—not as a prerequisite for making the business case viable.

The potential for by-product utilization is also limited by scale. For reference, Swedish oxygen consumption in 2020 was about 1.4 million tonnes, while projected oxygen output from electrolysis could reach 7.5 million tonnes by 2030 and nearly 19 million tonnes by 2045.[103] Figure 17 illustrates the current oxygen market compared to the volumes generated as by-products from hydrogen production in different cases. Our analysis shows that supplying one steel plant with hydrogen would generate approximately 640 kilotonnes of oxygen per year,

[103] Gustavsson, M., et al., *Potential use and market of Oxygen as a by-product from hydrogen production*, Energiforskrapport 2023:937, 2023

while hydrogen production for electrofuel synthesis would generate about 244 000 tonnes. These volumes make it unlikely that all producers will find outlets for their oxygen. Therefore, revenues from oxygen have only been included in cases where the process itself can utilize it, and otherwise illustrated through sensitivity analysis.

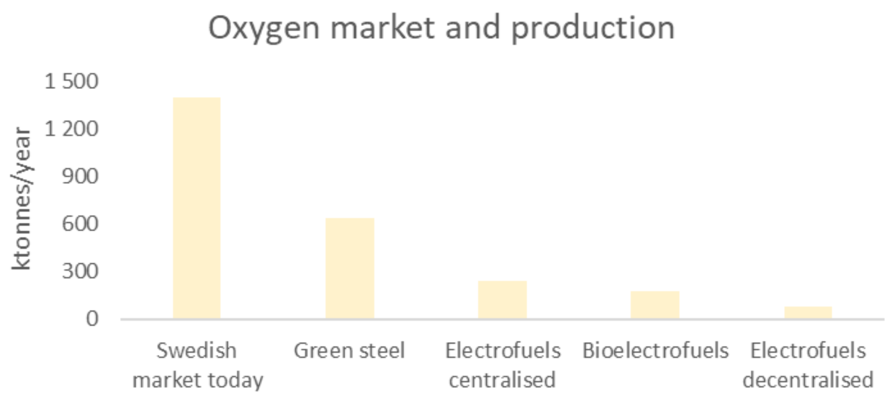

Figure 17. Swedish oxygen market and production volumes of oxygen from electrolysis for the different value chains (ktonnes/year).

Similarly, residual heat volumes are also significant: approximately 90 GWh from electrofuel production, nearly 400 GWh from bioelectrofuel production, and around 960 GWh from electrolysers in the steel case. In the electrofuel and bioelectrofuel cases, heat from electrolysers is not included, while for steel production the figure represents only electrolyser heat. This indicates that all cases offer additional potential for excess heat recovery at each site.

Figure 18 illustrates potential excess heat from the three value chains, both from the industrial process and electrolyser, compared to district heating deliveries in selected Swedish cities and national average. Heat recovery can significantly enhance resource efficiency by replacing alternative heat sources in district heating systems, thereby reducing primary energy demand and associated emissions. However, its economic viability depends on proximity to district heating networks and local integration opportunities. For context, district heating deliveries in 2023 were approximately 390 GWh in Skellefteå and 3.5 TWh in Gothenburg. Across Sweden, the average annual delivery per system is about 124 GWh, while the median is only 19 GWh[104]—highlighting a wide variation in system sizes and indicating that integrating very large volumes of excess heat will not be feasible for many networks.

[104] Energiföretagen, *Fjärrvärmens bränslen och produktion 2023*, https://www.energiforetagen.se/49d0d5/globalassets/energiforetagen/statistik/fjarrvarme/tillford-energi/energitillforsel-2023.xlsx

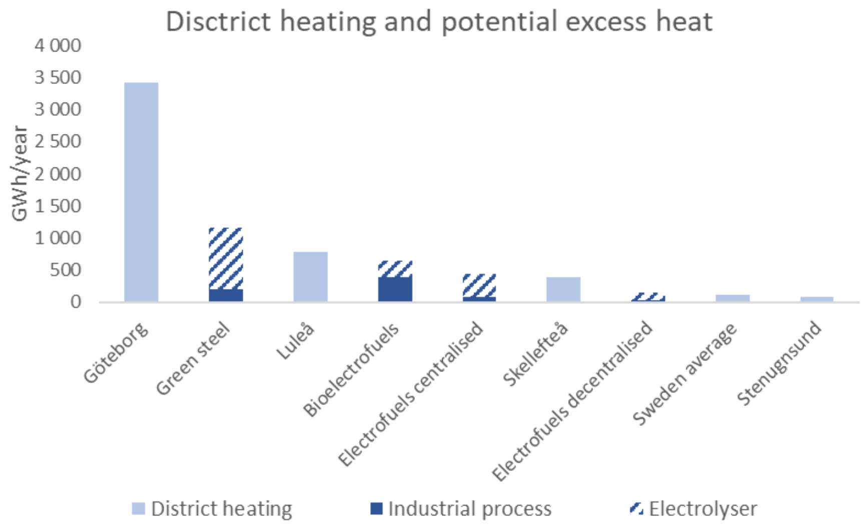

Figure 18. District heating deliveries and potential excess heat from different value chains, where excess heat originates from both the industrial process and the electrolyser, across different temperature ranges (GWh/year).

The analysis indicates that neither electricity grid expansion nor hydrogen pipeline development stands out as a clear socio-economic winner. Both infrastructures serve different purposes and complement each other in creating a resilient and cost-effective energy system. Electricity grid expansion benefits from established processes and extensive experience, while hydrogen infrastructure in Sweden is still at an early stage, with regulatory frameworks under revision and no completed concession cases, making direct comparison of permitting processes and timelines difficult.

Site selection for large-scale industrial projects is primarily driven by access to electricity. Grid connection remains the decisive factor for investment decisions, whereas hydrogen pipeline availability is still hypothetical. Other considerations, such as low electricity prices and proximity to CO_2 sources, influence location choices but are secondary to grid access. This strong dependency underscores the interlinked nature of electricity and hydrogen systems: hydrogen production through electrolysis is highly electricity-intensive, meaning that the rollout of hydrogen infrastructure cannot be planned in isolation from the power grid.

Public acceptance challenges affect both infrastructures. Overhead transmission lines often face resistance due to visual intrusion and concerns about electromagnetic fields, while hydrogen pipelines raise fears linked to unfamiliarity and perceived safety risks. Early and transparent stakeholder dialogue is critical for both, as is addressing cumulative impacts from multiple infrastructure projects in the same region. Co-planning electricity and hydrogen networks could help reduce land-use conflicts, limit environmental impacts, and strengthen local support, particularly in northern Sweden where major infrastructure projects intersect with extensive protected areas such as national parks and World Heritage sites.

From a resilience perspective, electricity grids provide high redundancy through established criteria such as the N-1 standard, ensuring the system can withstand the loss of a single component. Hydrogen pipelines, while generally not built with duplicate lines for backup, are considered to offer strong delivery reliability. Overall, the interviewed stakeholders did not perceive a significant advantage for either option in terms of resilience and robustness. However, they emphasized that a combined system would substantially enhance security of supply, reduce vulnerability to single-point failures, and enable sector coupling across industry, transport, and power. While hydrogen infrastructure currently depends on electricity for compressor operation, ongoing technical and regulatory developments could reduce this dependency over time, underscoring the need for integrated and forward-looking planning.

Land use considerations further strengthen the case for co-planning. Hydrogen pipelines generally have a smaller long-term footprint than overhead lines, although construction-phase impacts can be greater. Joint development of electricity and hydrogen infrastructure could minimize cumulative intrusion, reduce conflicts with defense and environmental interests, and lower the risk of costly delays.

Strategic studies and policy directions confirm that an integrated approach delivers the greatest socio-economic benefit. Svenska kraftnät concludes that co-planning electricity and hydrogen systems would enable stronger local support, reduce conflicts with nature and defense interests, and improve implementation efficiency[105]. At the European level, modelling by Neumann et al. (2023) shows that expanding both electricity grids and hydrogen pipelines yields the lowest overall system cost and highest flexibility. Their analysis found that combined development could reduce annual system costs by approximately €72 billion compared to a scenario with no expansion, while grid-only expansion saved €46–61 billion/year and hydrogen-only expansion €12–26 billion/year.[106] This demonstrates that electricity and hydrogen networks are stronger together: they address different needs, reduce overall costs, and create a more robust, adaptable energy system.[107,108]

In summary, there is no one-size-fits-all solution for hydrogen infrastructure. Decisions must integrate techno-economic factors with socio-economic considerations, by-product utilization, and system-level impacts. From a specific value-chain perspective, however, co-planning electricity and hydrogen networks may be less critical than ensuring that the chosen configuration is cost-competitive and practically feasible. In these cases, factors such as integration opportunities, local resource availability, and timing of investments often outweigh broader system-level synergies.

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105 Svenska kraftnät, *Förslag till hur el- och vätgasinfrastruktur kan samplaneras i Norrbottens och Västerbottens län*, 2025

106 Neumann, F. et al. *The potential role of hydrogen network in Europe,* Joule, Vol 7, 2023. https://doi.org/10.1016/j.joule.2023.06.016

107 Patonia, A. et al., *Hydrogen pipelines vs. HVDC lines: Should we transfer green molecules or electrons?*, 2023, OIES Paper: ET, No. 27, ISBN 978-1-78467-221-8

108 Neumann, F. et al. *The potential role of hydrogen network in Europe,* Joule, Vol 7, 2023. https://doi.org/10.1016/j.joule.2023.06.016

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Appendix A: Literature review of hydrogen pipeline infrastructure

Table 6. Key figures for hydrogen pipelines from literature review.

Report	Pipeline CAPEX	Pipeline O&M costs	Distance of pipeline	Operating pressure	Lifetime pipeline
H2eSIN	N/A	2 methods, 0.8 – 1% of CAPEX, or 5% of CAPEX	490 km	90 bar	40 years and 50 years respectively
European Hydrogen backbone	***New*** Small: 1.4 –1.8 M€/km Medium: 2 – 2.7 M€/km Large: 2.5 –3.4 M€/km ***Repurposed*** Small: 0.2 –0.5 M€/km Medium: 0.2 – 0.5 M€/km Large: 0.3 – 0.5 M€/km	0,8 – 1 % of CAPEX	53 000 km (pan-European network by 2040)	80 bar	40 years
Bothnian Bay Hydrogen Valley – Research report, LUT University	N/A	N/A	867 km	N/A	N/A
Underlagsrapport: Förslag till nationell strategi för vätgas, elektrobränslen och ammoniak, Energimyndigheten	10-50% more expensive than its natural gas equivalent.	N/A	Distribution pipelines: 1 – 3 000 km Transmission pipelines: 1 – 6 500 km	N/A	N/A
Extending the European Hydrogen	***New***	0.8 – 1.7% of CAPEX	39 700 km	40 – 80 bar for large	30 – 55 years

Backbone – A European hydrogen infrastructure vision covering 21 countries	Small: 1.4 –1.8 M€/km Medium: 2 – 2.7 M€/km Large: 2.5 –3.4 M€/km ***Repurposed*** Small: 0.2 –0.5 M€/km Medium: 0.2 – 0.5 M€/km Large: 0.3 – 0.5 M€/km			pipelines and 30 - 50 for small	
Global Hydrogen Review 2023, IEA	N/A	N/A	33 000 km (announced projects + existing pipelines by 2030, global).	50 – 80	N/A
Gas Decarbonisation Pathways 2020-2050, Gas for Climate	N/A	0.9 % of CAPEX	N/A	N/A	N/A
Hydrogen Production, Distribution, Storage and Power Conversion in a Hydrogen Economy - A Technology Review	0.19 – 0.94 M€/km depending on the terrain	N/A	N/A	N/A	N/A

Table 7. Key figures for compressors and recompression units

Report	*Capex recompression stations [EUR/MWe]*	*Compressor O&M costs [EUR/y]*	*Number of compression units*	*Lifetime recompression*
H2eSIN	2 Methods: 2.2 – 6.7 MEUR/ MWe or according to power requirements	2 methods: 1.7% of CAPEX or 15% of CAPEX	N/A	25 years and 15 years respectively
European Hydrogen Backbone	2.2, 3.4 or 6.7 MEUR/MWe	N/A	Smaller every 100 km or larger every 600 km	15 – 33 years
Gas Decarbonisation Pathways 2020-2050, Gas for Climate	N/A	1,7 % of CAPEX	Every 200 km	N/A
Hydrogen Production, Distribution, Storage and Power Conversion in a Hydrogen Economy - A Technology Review	N/A	0,027 EUR/kg.	N/A	N/A

Table 8. Key figures for hydrogen storage

Report:	*Cost of storage [EUR/kg H2]*	*Operating cost storage*	*Lifetime Storage*
H2eSIN	Lined rock cavern, min 20 bar - max 250 bars: 55,4 EUR / kg H2.	2% of CAPEX	30 years
Bothnian Bay Hydrogen Valley – Research report, LUT University	Levelized cost of storage: 3 EUR/MWh	N/A	N/A
Underlagsrapport Förslag till nationell strategi för vätgas, elektrobränslen och ammoniak, Energimyndigheten	LCOS for liquified storage of H2: 4.57 $/kg (small to medium volumes for daily/weekly cycles) LCOS for gaseous storage of H2: - Salt caves 0.23 $/kg (large volumes, month-weeks) - Depleted gas fields 1.90 $/kg (large volumes, seasonal) - Lined rock caverns (LRC) 0.71 $/kg (medium volumes, month-weeks)	N/A	N/A
Extending the European Hydrogen Backbone – A European hydrogen infrastructure vision covering 21 countries	N/A	50 annual storage cycles	40 years

Table 9. Assumptions for total hydrogen transmission costs.

Report	*Hydrogen production*	*Hydrogen storage*	*Compressor costs*	*New/repurposed pipelines*	*Design capacity*	*Geographical scope*
H2eSIN	No	No	Yes	New pipelines	100 %[109]	Sweden
European Hydrogen backbone (incl. extended backbone reports)	No	No	Yes	25 % new pipelines 75 % repurposed pipelines	75 %	Europe
Bothnian Bay Hydrogen Valley – Research report, LUT University	No	No	Yes	New pipelines	Unknown	Sweden + Finland
Global Hydrogen Review 2023, IEA	No	No	Unknown	New pipelines	75-100 %	Global
Gas Decarbonisation Pathways 2020-2050, Gas for Climate	No	No	Yes	Unknown	Unknown	Unknown
Cost of long-distance energy transmission by different carriers	No	No	Yes	Unknown	100 %	USA
Energy Transmission Commission through Underlagsrapport: Förslag till nationell strategi för vätgas, elektrobränslen och ammoniak, Energimyndigheten	No	Yes, salt cavern.	Yes	New pipelines	Unknown	Global
Blooberg NEF through Underlagsrapport: Förslag till nationell strategi för vätgas, elektrobränslen och ammoniak, Energimyndigheten	No	Yes. 20% assumed for pipelines in a salt cavern.	Yes	New pipelines	Unknown	Global

[109] Designed to match local demand for hydrogen after local hydrogen production is taken into account.

Appendix B: Outlook in neighboring countries

This chapter zooms in on the hydrogen infrastructure development in the neighboring Swedish countries Denmark, Finland, Norway and Germany. This variety of strategies among Sweden's neighboring countries offer a range of perspectives that could influence the direction of Sweden's hydrogen journey.

This chapter was finalized in 2023 and there only include information up to that date. Developments may have occurred since it was written.

7.7.1 Denmark

Denmark is actively pursuing the development of its hydrogen and electricity grid, driven by a commitment to reduce greenhouse gas emissions by 70% by 2030. This ambition is supported by Denmark's robust wind energy sector, particularly offshore wind, which provides a significant source of renewable energy for hydrogen production and e-fuels through Power-to-X (PtX) technologies. Denmark is a fourth runner alongside with Spain, Germany and Netherlands in terms of hydrogen production.

In December 2021, the Danish government showcased its dedication to a sustainable future by unveiling a Power-to-X strategy with a goal of achieving 4-6 GW of electrolysis capacity by 2030. This aligns with the country's broader energy and environmental objectives, positioning Denmark at the forefront of renewable energy innovation.

The Danish national grid operator, Energinet, plays a crucial role in this transition. It manages a gas transmission pipeline grid stretching approximately 925 km, with international connections to Germany and Sweden. The forthcoming Baltic Pipe, which will connect Norway, Denmark, and Poland, is set to extend the grid to around 1 250 km.

Looking ahead, Denmark recognizes the importance of establishing a hydrogen infrastructure before 2030 to accommodate the several large-scale electrolysis projects announced within its borders, aiming for a collective installed capacity of about 6.5 GW by 2030. Energinet has embarked on evaluating the feasibility of converting a 93 km segment of its existing gas infrastructure for hydrogen transmission. This initiative hinges on the successful requalification and material testing to ensure the safe and efficient delivery of hydrogen across the nation.[110]

As Denmark also intends on more than doubling the electricity capacity in the country, there is a need to expand the electricity grid to integrate upcoming renewable energy sources, particularity on- and offshore wind. From 2023 to 2026, Energinet will invest a total of DKK 41 billion in expanding and future-proofing the Danish electricity grid. Among the many areas seeing major changes are

[110] European Hydrogen Backbone, *Extending the European Hydrogen Backbone – A European hydrogen infrastructure vision covering 21 countries*, 2022.

Lolland-Falster and Southern Zealand, where the electricity grid is being cabled and expanded from south to north.[111]

7.7.2 Finland

Finland is advancing its hydrogen and electricity grids to reach carbon neutrality by 2035. With significant wind energy prospects, Fingrid Oyj, the Finnish electricity TSO, aims to integrate 25 GW of wind power by 2035. Recognizing the potential for hydrogen and power-to-X production to cater its industrial needs, Finland is exploring the establishment of hydrogen valleys to meet the significant industrial demand for low-carbon hydrogen and to utilize clean energy resources efficiently.

The strategic development of Finland's hydrogen infrastructure is focused on three key regions. The Bothnian Bay region and the west coast are targeted due to their significant renewable energy sources and hydrogen demand. The south and southeast areas, including Uusimaa and Kymenlaakso, have substantial existing and projected hydrogen demand. Lastly, the Southwest Finland and Satakunta regions are considered due to their potential hydrogen demand and renewable energy resources.

To address the anticipated supply and demand in regions with little or no existing gas transmission infrastructure, the plan is to construct new hydrogen pipelines. Gasgrid Finland (Finnish gas TSO), together with the Swedish gas TSO Nordion Energi, has initiated the Nordic Hydrogen Route—a large-scale, greenfield cross-border hydrogen infrastructure project in the Bothnian Bay region, aiming to operationalize the network by 2030. This interconnection could foster a Finnish-Swedish hydrogen market in the Bothnia Bay area.[112]

Further, Fingrid is taking steps to expand the electricity grid to support these changes. The Aurora Line, scheduled for completion in 2025, will boost the electricity transmission capacity from Sweden to Finland by 800 MW. Plans for Aurora Line 2 are also underway, which will establish a fourth alternating current (AC) connection to Sweden and a third interconnector to Estonia.[113]

Both Gasgrid Finland and Fingrid are collaborating to explore future pathways for hydrogen production and consumption in Finland. Their goal is to assess the requirements for energy transmission infrastructure that will support these future developments, underscoring the growing relevance of hydrogen in Finland's energy landscape.[114]

7.7.3 Norway

Currently, the primary sources of Norwegian emissions are from oil and gas extraction, manufacturing, transportation, agriculture, and waste. The Norwegian

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[111] Energinet (2022), *LONG-TERM DEVELOPMENT NEEDS IN THE POWER GRID*

[112] European Hydrogen Backbone, *Extending the European Hydrogen Backbone – A European hydrogen infrastructure vision covering 21 countries*, 2022.

[113] Fingrid (2022), *THEME: SELF-SUFFICIENT IN EMISSION-FREE ELECTRICITY*

[114] Fingrid & Gasgrid Finland (2022), *Scenarios: Energy transmission infrastructures as enablers of hydrogen economy and clean energy system*

Climate Change Act mandates a low-emission society by 2050, seeking reductions of 90–95% compared to 1990 emissions, which differs slightly from the other Nordic countries.[115]

In response, the Norwegian government unveiled a hydrogen strategy in 2020, recognizing the country's extensive industrial experience in the hydrogen value chain. With ideal conditions for clean hydrogen production and use, Norway's companies and technology sectors are actively developing solutions for hydrogen production, distribution, storage and usage across various industries. Leveraging its large gas reserves and renewable energy potential, Norway envisions transforming natural gas into clean hydrogen, utilizing carbon capture and storage (CCS) technology, with the Norwegian continental shelf serving as a potential CO_2 storage site.

Gassco, Norway's independent system operator (ISO) for gas transportation, manages a network comprising 9 000 km of subsea pipelines, gas processing plants, offshore platforms and terminals across several European countries. There is potential to repurpose these natural gas pipelines for hydrogen export to key markets like Germany, the Netherlands and Great Britain.

As part of the grid expansion efforts, Norway is exploring the relevance of hydrogen within its energy landscape, considering its role in meeting emission targets and its increasing prominence in the global move towards clean energy. The country is assessing the expansion and adaptation of its existing infrastructure to accommodate hydrogen transport and export, signaling a significant commitment to hydrogen as a cornerstone of its future energy strategy.

7.7.4 Germany

The government coalition intends to pursue the goal of climate neutrality by 2045 set by the previous Government. In its coalition treaty the Government proclaims a technology neutral approach to energy policy that includes cross-sector instruments aimed at achieving these targets. Hydrogen features prominently in both the Government's industrial policy and its energy policy strategy. Hydrogen is considered alongside electricity as a prerequisite for Europe's ability to act and compete in the 21st century. The Federal Government expects high future demand for hydrogen. Accordingly, the hydrogen economy is to be ramped up quickly and comprehensively with the necessary resources.

The primary focus is set on domestic green hydrogen for which the government has announced to raise the target for installed capacity from 5 to 10 GW by 2030. However, blue hydrogen is also considered an option. Generally, hydrogen imports will play a major role. Appropriate hydrogen networks and import structures are to be created timely also within international co-operations. Moreover, the Government plans to accelerate approval procedures.

In November 2021, the German TSOs published maps for a German H_2 grid in 2030 and 2050. These demonstrate the feasibility to establish a cost-efficient and

[115] Klimatutvalget 2050, *Mandate*, https://klimautvalget2050.no/mandate/, published n.d., used 2023-10-10

reliable hydrogen grid in Germany. The German hydrogen network 2030 connects different demand clusters like Ruhr Area, Rhine-Main Area, Eastern Germany, Central German chemical triangle and Bavaria with hydrogen sources in Germany, especially in the North, and with important import routes. As such, pipeline connections to the Netherlands, the North Sea and to Denmark and to Poland and the Baltic Sea for integrating offshore pipelines and possible imports are foreseen. While in the Southeast import connections to Austria and the Czech Republic emerge.

In the West, connections to Belgium and France occur, while a new connection to Poland in the East will be available for imports to meet growing national demand in different regions. The compiled German H_2 network has a total length of about 5,200 km by 2030, with some 3,700 km of repurposed natural gas pipelines, and would be able to meet a hydrogen demand of around 70 TWh. By 2040, a new interconnection emerges to Switzerland and an additional connection with Poland and Czech Republic, thereby further enhancing security of supply. The German H_2 network for 2040 is derived from the FNB Gas network publications for 2030 and 2050. A 50 km pipeline in Bad Lauchstädt Energy Park has reached Final Investment Decision in June 2023, including a pipeline to TotalEnergies Refinery.[116]

[116] IEA, *Global hydrogen review,* 2022.

Green hydrogen from a socio-economic perspective

Hydrogen is expected to play a central role in Sweden's climate transition. This report analyzes how different infrastructure choices: electricity grids and hydrogen pipelines, affect the costs and integration of green hydrogen and electrofuels in key value chains such as green steel, electrofuels, and bioelectrofuels.

The findings show that neither electricity grids nor hydrogen pipelines offer a universal advantage; the best solution depends on local conditions and scale. Electricity price is the most decisive factor for competitiveness, while infrastructure costs are a minor part of total production costs. Co-location and the use of by-products like oxygen and heat can improve cost efficiency, especially in bioelectrofuel systems, but these benefits are highly context dependent.

Socio-economic factors such as land use, permitting, and public acceptance add further complexity, highlighting the importance of early stakeholder engagement and coordinated planning. Ultimately, the report concludes that integrated development of electricity and hydrogen infrastructure provides the greatest socio-economic benefit and flexibility for Sweden's energy future.

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