Pre-feasibility Study for a Danish-German Hydrogen Network

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1. Aim of the study

Hydrogen will play a key role in the future European energy system ensuring that the EU reaches carbon neutrality by 2050. In 2020, the EU Commission and several EU member states presented dedicated hydrogen strategies with ambitious targets for renewable hydrogen production and deployment. Different EU countries, however, have different competitive advantages for growing a hydrogen economy. Cross border hydrogen networks could facilitate EU market growth in bringing together demand and supply for renewable hydrogen in a cost-effective manner.

Building on the current collaboration with respect to the gas interconnection point between Denmark and Germany, Energinet and Gasunie have initiated a pre-feasibility study for a dedicated hydrogen pipeline network between Denmark and Germany transporting hydrogen produced from renewable electricity in Denmark to customers in Germany.

The study addresses the following:

- The export potential of renewable hydrogen from Denmark.
- The market for hydrogen in Germany and factors influencing demand.
- The technical feasibility for realizing a hydrogen connection, which is partly based on repurposing existing methane infrastructure on two possible routes from Esbjerg (DK) to Hamburg (DE) and Holstebro (DK) to Hamburg (DE).
- Design features for a scalable network with different compressor station configurations and indicative investment costs.

The goal of this study is to foster market dialogue to better understand how hydrogen infrastructure can enhance the value proposition and reduce financial risks of hydrogen related investments.

The technical results from the study are indicative and merit further analysis.

2. Executive summary

Denmark has a significant potential for Power-to-X (PtX) and the production of renewable hydrogen from solar and wind. In the meantime, demand for hydrogen in Denmark is relatively limited and the supply of hydrogen is therefore expected to surpass demand in the short and longer term. As a result, Denmark could become a net-exporter of hydrogen.

This study projects an export potential of 2-15 TWh, 3-22 TWh and 5-28 TWh in the years 2030, 2035 and 2040 (corresponding to 0-3 GW, 1-4 GW and 1-6 GW assuming 5000 full load hours). The lower estimates are considered conservative, particularly considering the market's growing appetite for production of large-scale PtX. According to publicly available information a total of 4,5 GW electrolyser capacity could be developed in Denmark already by 2030.

Germany could be a potential off-taker of hydrogen from Denmark. Contrary to the limited demand for hydrogen in Denmark, German industries already uses significant amounts of hydrogen from fossil sources and the demand potential for direct use of renewable hydrogen is expected to increase in both existing and new hydrogen sectors. According to the German National Hydrogen Strategy, demand for hydrogen can reach 90-110 TWh already in 2030 (BMWi, 2020). This is far more than the targets set for renewable hydrogen production in Germany[1], hence import of hydrogen is expected to play a significant role in fulfilling demand for hydrogen in Germany.

The growth of hydrogen markets in Denmark and Germany is facing a classical chicken and egg dilemma whereby future customers require reliable supply of renewable hydrogen – while producers of renewable hydrogen need assurances from the market to make final investment decisions. Bringing together supply and demand will – in most cases – require some form of transport, such as hydrogen networks. Investment in hydrogen infrastructure could increase market value and lower the financial risk associated with development of both supply and demand side. A hydrogen network from Denmark to Germany could support national PtX demand in Denmark and export of energy in the form of hydrogen to Germany and optimize value chains.

1. The National Hydrogen Strategy sets a goal of realizing 5 GWe electrolyser capacity in 2030 and potentially 10 GWe in 2035. This corresponds to 14 and 28 TWh of hydrogen production assuming the electrolyser units have 4000 full load hours per year on average.

This study shows that an initial hydrogen network between Denmark and Germany can be built in expansion stages and later be scaled up to accommodate for higher demand of transport capacities. A pipeline of 340 km connecting Esbjerg and Heidenau near Hamborg can – in an initial phase – transport up to 2.5 GWh/h of hydrogen without the use of pipeline compressors. The capacity can later be increased up to 8.6 GWh/h by use of compression power. The study also finds that location of compressor stations has an influence on the costs and possible transport capacities of the system.

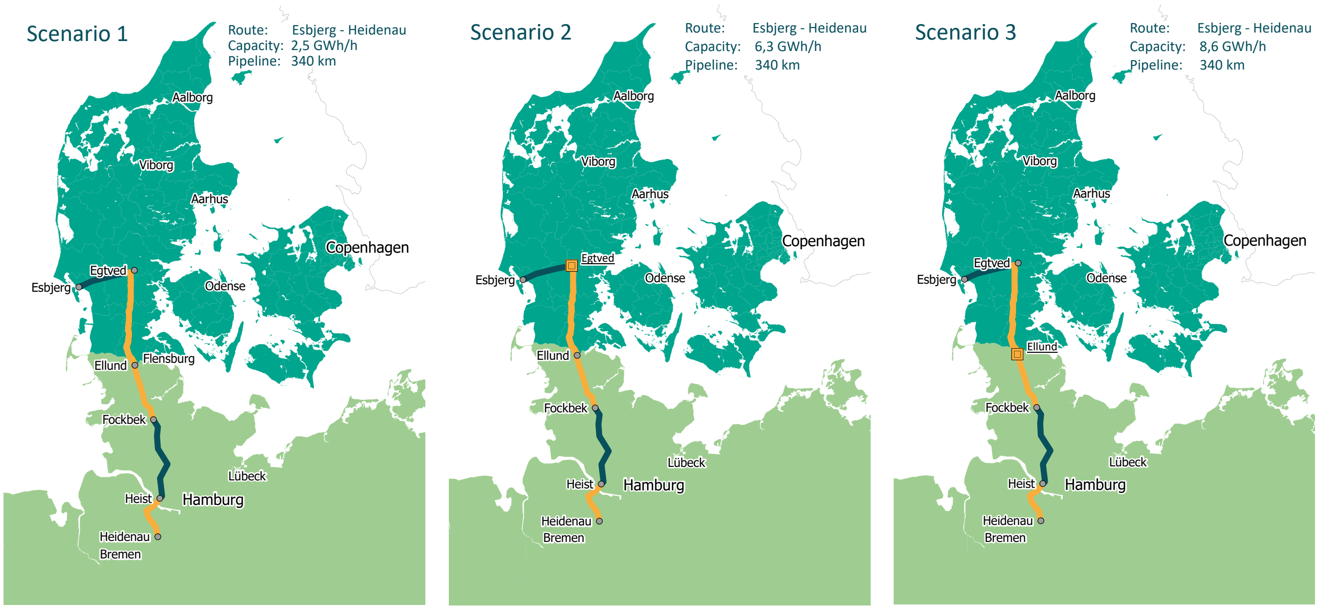

Figure 1-3: A scalable hydrogen network between Esbjerg in Denmark and Hamburg in Germany. Addition of compressor station in Ellund increases the hydrogen transport capacity to 8,6 GWh/h.

The total cost of a hydrogen network depends, among other things, on the demand for transport capacity, the length of the pipelines, the variability of renewable generation and the possibilities for repurposing existing gas infrastructure. In a scenario where a maximum of 2.5 GWh/h is transported between Esbjerg and Heidenau near Hamburg, this study finds CAPEX to be around 390 MEUR. If the capacity is increased by adding a compressor station in Ellund, the system could transport up to 8.6 GWh/h of hydrogen. In this scenario, CAPEX is estimated to be 670 MEUR where about 40 % of the costs

(280 MEUR) is estimated for the compressor station. In this study, operational costs are based on compressor power only and we assume maximum utilization of the network. Lastly, we assume that considerable costs savings can be realised by repurposing of existing gas pipelines. This study assumes that 50-60 % of existing gas pipelines can be repurposed for hydrogen in the future.

Large-scale and long-distance hydrogen transport systems is technically new and a number of simplified measures have been taken for calculations of costs in this study. The results are therefore indicative and merit further analysis.

We made a comparison to transport of hydrogen via trucks and ships and find that transport of hydrogen in pipelines – for the volumes and distances assumed in this study – is the most feasible option, both from a cost and logistical perspective.

While the value of the system increases with higher demand for transport capacities, a system of initially ~2.5 GWh/h could support market growth in a Northern cluster between Denmark and Northern Germany in a cost-effective manner. However according to the German Network Development Plan, Hamburg could be connected to a southbound hydrogen network already by 2025. To ensure a cost-effective and timely development of the hydrogen network, it should be designed and constructed to meet the longer-term forecast of hydrogen demand.

The possibility of repurposing gas pipelines should consider future demand for transportation of methane and bio-methane. We assume that a parallel system for methane and hydrogen will co-exist for a long time, also in 2050, where the methane network will be converted to 100 % green gas.

Key messages of the study

The study has the following key messages

1. It can be done - A hydrogen connection between Denmark and Germany can be realized rather quickly. The development depends on the needs in the hydrogen market.

2. It can be done flexibly - The design of the hydrogen connection is scalable. In the initial stages, significant capacity can already be made available through a network consisting of pipelines only (saving on compression in the initial stages). Depending on the developments in hydrogen supply and demand, the capacity of the pipelines can be increased further by installing compression power.

3. It can be done efficiently - Repurposing of existing pipelines reduces costs and should be considered where possible.

4. Clear market signals are needed – while we have provided an exemplified design of a hydrogen network, Energinet and Gasunie now invite stakeholders to get in contact in order to better understand the actual demand for hydrogen transport between Denmark and Germany.

Who we are

Gasunie

Gasunie is a European energy infrastructure company. Gasunie's network is one of the largest high-pressure pipeline networks in Europe and consists of over 15,000 kilometers of pipelines in the Netherlands and Germany. Gasunie is helping to accelerate the transition to a CO2-neutral energy supply. The company believes that innovations in the gas sector can make an important contribution to this, for example in the form of renewable gases such as hydrogen and green gas. When it comes to hydrogen, scale and an integrated approach to the entire hydrogen chain are important. Gasunie is therefore investing in innovative partnerships and a hydrogen backbone for transport and storage. Both existing and new gas infrastructure are important in this context.

Energinet

Energinet is an independent public enterprise owned by the Ministry of Climate, Energy and Utilities of Denmark. Energinet's core business involves designing, maintaining, and developing the Danish energy system for electricity and gas with a focus on finding cost-effective ways to integrate higher shares of renewables into the system while maintaining a high level of security of supply. In the view of EU's climate ambition, Energinet sees a need for coordinated and holistic planning of energy infrastructure across electricity and gas, including new energy carriers such as hydrogen. Energinet welcomes and is active in the work undertaken by European TSOs with regards to identifying possible hydrogen cross-border networks, which can bridge the regional disparities between renewable hydrogen generation and demand for hydrogen across Europe.

3. An emerging hydrogen market in the EU

The year 2020 was in many ways a breakthrough year for hydrogen. Globally, several national governments have presented ambitious strategies for upscaling production and utilization of renewable and decarbonized hydrogen, especially for the so-called 'hard-to-abate' sectors. European countries with existing hydrogen demand are accelerating efforts by setting high targets for electrolyser capacity already 2030. The same trend is seen at the EU level, where the European Commission – as part of its long-term goal of carbon neutrality in 2050 – launched strategies on hydrogen, offshore renewable energy and sector integration. The generation of hydrogen via electrolysers will follow the availability of renewable electricity from wind and solar. The electrolysers therefore provide essential flexibility for the electricity system, and in doing so, electrolysers support higher integration of renewable energy. As a result, there is a clear role for hydrogen in all three strategies, demonstrating the role of hydrogen as a catalyst for sector integration and utilization of renewable energy.

The goal of the European Commission's hydrogen strategy is to develop at least 40 GW of installed electrolyser capacity across the EU in 2030 (EC 1, 2020). However, the production of hydrogen will be quite intermittent on a shorter time-period and might show seasonality as well. Hydrogen infrastructure with pipelines and underground storages is well equipped to handle the volatility of renewable generation and provides seasonal storage of large volumes of energy in the form of hydrogen.

To realize Europe's ambitions targets for increasing offshore renewable energy and hydrogen production, it will be essential to have regional and cross sectorial coordination, particularly when it comes to infrastructure planning and market. This study is a pro-active attempt towards that end.

One of the proposed measures in the European Commission's Hydrogen Strategy concerns repurposing existing gas networks to transport pure hydrogen as declining gas demand leads to available capacity (EC 1, 2020). And in mid 2020, 11 Gas-TSOs including Energinet and Gasunie, presented a vision for a European Hydrogen Backbone, which is largely based on repurposing existing gas infrastructure (Guidehouse, 2020).

The European Backbone vision has recently been updated with expansion to Eastern Europe adding additional km of pipelines (Guidehouse, 2021). Repurposing of existing pipelines has also been considered in this study.

Along with the increased political awareness towards hydrogen, an unprecedented number of private investments are now floating into the fast-developing hydrogen sector. Both energy incumbents and new players share the vision that hydrogen will play a major supporting role in the future energy system. In doing so, hydrogen will substitute the energy consumption, which is covered by fossil fuels today.

4. Hydrogen and PtX in Denmark

Denmark has – with its location by the North Sea – an abundant resource of offshore wind. As part of the 2020 Climate Agreement, a target of 6 GW additional renewable electricity from offshore wind is set for Denmark in 2030 (FM, 2020). Most of this capacity will be built on two energy islands planned in the North Sea and Baltic Sea. Onshore renewable electricity production (from solar and onshore wind) is also expected to grow, particularly solar PV due to significant reductions in costs. According to projections from the Danish Energy Agency, Denmark could reach installed renewable electricity capacity of 22 GW in 2030 and 29 GW in 2040 (DEA 1, 2020). With an installed base of approximately 7 GW in 2020, this corresponds to a quadrupling in just two decades.

The foreseen expansion of renewable electricity leads to more fluctuating production, which – all things equal – increases the risk of curtailment of renewable electricity. This reinforces the need for Power-to-X (PtX) and the conversion of renewable electricity into hydrogen as a flexible consumption mechanism that can help balance the power grid and reduce the overall system costs of integrating renewable electricity into the system. PtX reduces the need to invest in power grid expansions and upgrades, especially when the location of electrolysers is chosen optimally with respect to power grid congestions and availability of dedicated hydrogen infrastructure.

Power-to-X and renewable hydrogen is expected to play a significant role in the long-term decarbonization of hard-to-abate sectors, such as, certain industries (i.e. steel, refineries and chemical industry (e.g. ammonia production), heavy land transport, aviation and shipping. While other countries foresee direct use of hydrogen in heating and passenger vehicles, these sectors are expected to be mostly electrified in Denmark. The renewable hydrogen production potential is however expected to surpass national demand for hydrogen and synthetic fuels both in the short and long-term, which positions Denmark to become a net exporter of hydrogen.

The appetite for PtX is growing in Denmark and over the last year, the market has announced plans for large-scale PtX. If these projects move forward with final investment decisions, a total of 4,5 GW electrolyser capacity could be realised in

Denmark around 2030. The projects cover the entire value chain from production to consumption. A share of them foresee demand for hydrogen as methanol for use in the aviation, maritime and heavy land transport sectors as well as ammonia for agricultural fertilizers and shipping. Other projects envision the use of renewable hydrogen in the refinery industry. Lastly, a group of partners including Gas Storage Denmark are working on the Green Hydrogen Hub, whereby hydrogen will be converted into energy through Compressed Air Energy Storage (CAES) and stored in salt caverns (Gas Storage Denmark, 2020).

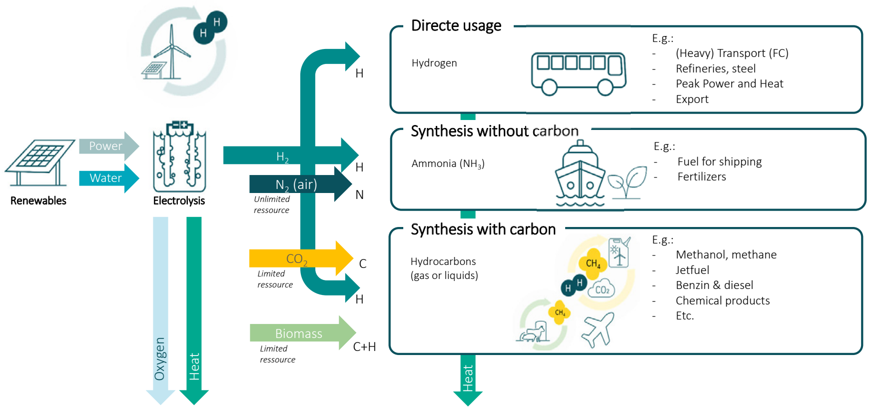

Figure 4: PtX demand pathways.

Danish export potential

The Danish hydrogen export potential could be triggered by renewable energy development, national PtX demand and demand for import of renewable hydrogen from other countries. In this chapter we simulate the export demand potential only considering estimated national PtX demand and renewable hydrogen production. The import potential of Germany is covered in chapter 5.

Projected hydrogen production in Denmark is assumed to only come from electrolysers based on renewable energy from wind and solar power. To account for the uncertainty for PtX production we assume a low, best and high scenario for renewable energy generation. This generates a range for hydrogen production of 2-18 TWh in 2030, 4-28 TWh in 2035 and 6-38 TWh in 2040 (see figure 5). The volume of hydrogen produced (TWh H_2) is calculated assuming a 66 % (based on lower heating value - LHV) conversion efficiency. To put it into perspective, the Danish Energy Agency projects 15 TWh electric consumption for PtX – or 3 GW electrolysers capacity – in 2040 (DEA 1, 2020). It should be noted that 2020 was the first year PtX was included in the Danish Energy Agency's 20-year projections and in light of the aforementioned announcements from the market of around 4,5 GW in 2030, our low and best estimate are therefore conservative estimates.

The national PtX demand for Denmark is based on the Danish Energy Agency's latest projections[2] for electricity consumption used for Power-to-X. While the projections only extend to 2040, an extrapolation that assumes Denmark is carbon neutral in 2050, is used to project PtX demand after 2040. Import and export is not taken into consideration (DEA 1, 2020).

We have calculated the export potential by subtracting the best estimate of the national PtX and the best and high estimate scenarios for projected renewable hydrogen generation. This generates export potential in the ranges of 2-15 TWh, 3-22 TWh and 5-28 TWh in the years 2030, 2035 and 2040. This corresponds to 0-3 GW, 1-4 GW and 1-6 GW assuming the electrolysers run 5000 full load hours per year (see figure 5).

2. The Danish Energy Agency (Energistyrelsen) each year publishes projections for the energy consumption and production patterns looking 20 years into the future. Energinet uses these projections to plan and develop the transmission network for electricity and gas. 2020 was the first year the Danish Energy Agency included projections on Power-to-X and the PtX demand presented in this report is therefore associated with a degree of uncertainty.

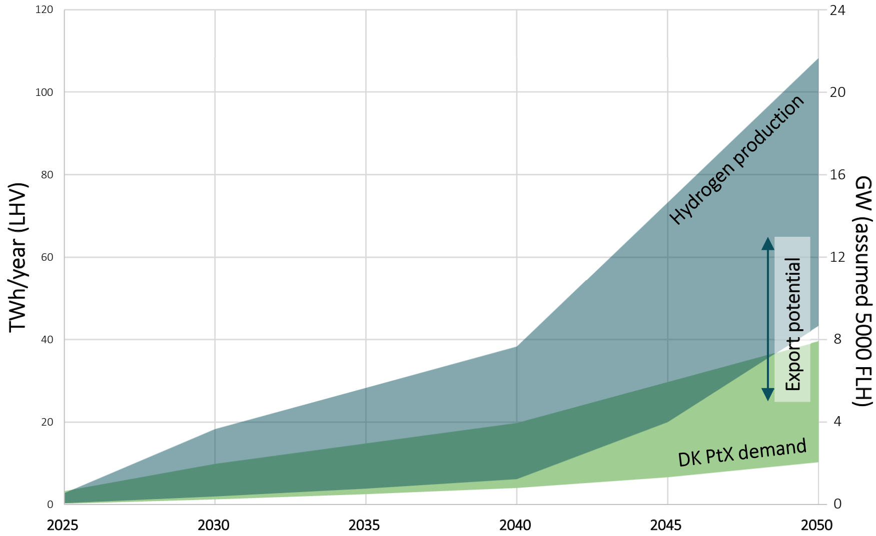

Figure 5: H_2 Export potential derived from subtracting projected PtX demand and electric consumption for PtX according to the Danish Energy Agency's projections (DEA 1, 2020) combined with Energinet's internal simulations for renewable hydrogen production. (LHV = Lower Heating Value, FLH = Full Load Hours).

It is worth observing that even with higher PtX demand, the volumes of hydrogen produced is expected to exceed well beyond what can efficiently be translated into national demand. In this situation, cross-border hydrogen infrastructure will be essential to enable export of hydrogen or synthetic fuels to neighboring countries with large import needs, such as Germany and Sweden. Since the vast majority of Denmark's renewable electricity production is expected to be developed in Western Denmark, this part of Denmark also has the largest potential for large-scale PtX. A hydrogen pipeline system connecting Western Denmark and Germany could stimulate national demand in the longer run and provide the foundation for a growing hydrogen economy in Denmark and Germany.

5. Hydrogen in Germany

Germany has committed itself to achieving carbon neutrality by 2050, which requires replacement of all fossil energy carriers by 2050. As a result, efforts are being taken to increase renewable energy generation, enhance energy efficiency and increase direct electrification. However, the potential of renewable energy generation in Germany is limited, which means Germany will be highly dependent on import of renewable energy. As such, Germany will continue to import a large share of its primary energy demand, which today mostly constitute of coal, oil and gas. On the path to carbon neutrality direct electrification has some limitations, especially in the decarbonization of the heavy industries. Carbon neutral energy carriers, such as hydrogen, are therefore considered essential for the decarbonization of German industries which are so important for the German economy.

Initiated by the German Ministry of Economic Affairs, a broad discussion (German Gas Dialog) of the future role of gas in a CO_2 neutral energy system was held in 2019. The discussion confirmed that gas – especially renewable hydrogen – and existing gas-infrastructure will play a key role in Germany's energy transition. This was followed by the announcement of the National Hydrogen Strategy (NHS) in June 2020. The strategy presents 38 different measures for supporting a hydrogen economy. Included are measures to support production of hydrogen (in Germany and abroad), generate and stimulate demand for hydrogen in different sectors and support the development of hydrogen infrastructure (pipeline transport, import and storage). 7 billion euros have been reserved to stimulate market growth and mature hydrogen technologies in Germany and another 2 billion euros to fostering international partnerships (BMWi, 2020).

Renewable hydrogen demand potential in Germany

The role of hydrogen in Germany's energy transition is addressed in a number of recent studies e.g. dena (2018), Agora (2020), Fraunhofer ISE (2020). However, projected demand for hydrogen in these studies differs quite substantially. While the National Hydrogen Strategy foresees

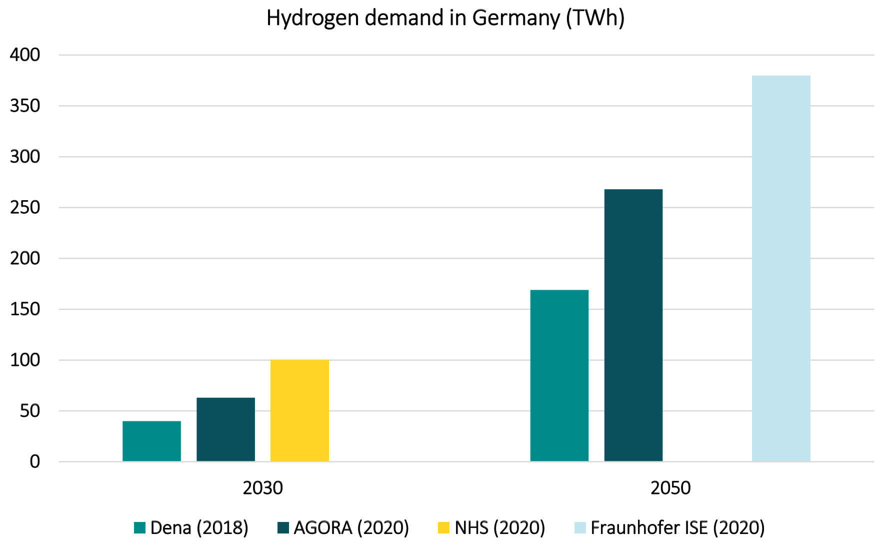

Figure 6: Scenarios for hydrogen demand in Germany (dena, 2018); (AGORA, 2020); (BMWi, 2020); (Fraunhofer ISE, 2020). The National Hydrogen Strategy (NHS) only projects hydrogen demand for 2030, and Fraunhofer ISE only projects hydrogen demand in 2050.

demand of hydrogen between 90 and 110 TWh (BMWi, 2020), the DENA (2018) study foresees demand to be around 40 TWh in 2030. In 2050, the demand projected in the studies lies between 169 and 380 TWh (see figure 6).

Hydrogen can be used in different sectors; however not all technically possible applications of hydrogen are likely to be used in the future. The utilization will be strongest in sectors, where hydrogen provides a specific additional value, besides from providing energy (AGORA, 2021). This is for example the case for the steel industry, where hydrogen also causes chemical reduction in the steel process. Demand for hydrogen is expected to be largest in the steel and chemical industry and heavy transportation as illustrated in table 1. A deep dive into the different sectors for hydrogen is provided in the following sections.

		2030				2050			
Study	Scenario	Steel	Chemical/ Refineries	Transport	Energy/ Heat	Steel	Chemical/ Refineries	Transport	Energy/ Heat
Dena (2018)	EL95	10 TWh		27 TWh		37 TWh		120 TWh	
Dena (2018)	TM95	19 TWh		18 TWh		64 TWh		92 TWh	
AGORA (2020)		15 TWh	15 TWh	4 TWh	20 TWh	36 TWh	33 TWh	40 TWh	156 TWh
Fraunhofer ISE (2020)	R100					100 TWh		170 TWh	70 TWh

Table 1: Scenarios for hydrogen demand divided in sectors in 2030 and 2050.

Feedstock/Chemical use of hydrogen

Germany is producing roughly 40 million tonnes of steel each year and is the largest producer in the EU. Steel is an important raw material for a number of sectors that are essential to the German economy. This includes the automobile industry, the construction industry and mechanical engineering. Since the steel industry is emitting one third of the German industry's greenhouse gas emissions, this sector has a particular challenge to reduce its carbon footprint. Of the 40 million tonnes of steel produced, 70 % is produced from iron ore in coal fired blast furnaces. To produce iron from ore, the iron-oxide of the ore has to be reduced in a chemical reaction to iron. The preferred future production route of the German steel industry is to switch to a process based on Direct Reduction Iron (DRI). DRI is more efficient than the blast furnace process and provides a significant CO_2 reduction even if fueled with fossil gas. If this process is fueled with (renewable) hydrogen, significant CO_2 savings can be realized. The use of DRI implies structural changes into the production process and is quite costly, however, there is hardly any alternatives to DRI for a carbon neutral steel production. The role of steel in the German economy – also in the future – and the potential for switching to DRI, is therefore expected to create significant demand for hydrogen in this sector.

In the chemical sector, the technical potential for renewable hydrogen is particularly high for production of ammonia and methanol. An essential feedstock to the chemical industry is naphtha. Naphtha is produced in refineries as a fraction in the distillation of oil. Naphtha is used to produce two high volume classes of basic chemicals – aromata and olefine. To reduce the carbon footprint of this product, naphtha (or the base chemicals directly) can be synthesized based on hydrogen and CO_2. The resulting demand potential for hydrogen can reach 300 TWh (VCI, 2019) in the chemical sector alone in 2050. However, it should be noted that this requires access to green carbon and the associated cost of Direct Air Capture (DAC) to produce the green carbon have to be taken into account. Furthermore, most of the hydrogen needed for the process would have to be imported. It might therefore be less costly to import the base chemical products (e.g. ammonia and methanol) or synthetic naphtha directly. This means that the actual demand for hydrogen in the chemical sector could be much smaller than the technical potential.

Transport sector

Use of hydrogen in the mobility sectors has a number of advantages compared to electric vehicles. Hydrogen has much higher energy density compared to batteries and the time it takes to fuel a vehicle (car, truck, ship or train) with hydrogen is much faster than charging a battery with electricity. The arguments for the use of hydrogen in transportation are strongest for heavy duty trucks, trains and ships. For light transporters and passenger cars, battery electric vehicles (BEV) are, according to most studies, considered to be a more efficient option.

While the potential for the use of hydrogen in vehicles has some advantages, the roll-out of hydrogen fueling stations could be a limiting factor. Only ~ 90 fueling stations are installed in Germany today, which creates uncertainty on the future market for hydrogen in the land-based transport sector.

Heating Demand & Energy Sector

Demand for gas or hydrogen in heating and demand for gas or hydrogen in the electricity sector are interlinked. A highly electrified energy system with a clear seasonal demand will need more thermal generation (capacity and energy). Yet, the future role of carbon neutral energy carriers (bio-methane, syn-gas, hydrogen) in the heating sector is heavily discussed. Some studies assume, that gas and hydrogen will play only a small role in the future heating system, since the majority of demand should be covered by electric heat pumps. Heat pumps are seen as the most efficient solution because the heat produced is multiple times higher than the electricity consumed. Gas will play a role in district heating mainly in a combined heat and power (CHP) set-up or in combination with and as back-up for large scale heat-pumps. The COP[3] (Coefficient of Performance) of a heat-pump is depending on the temperature of the available heat reservoir. Efficiency will therefore be low in the winter if most households use ambient air as heat source. Buildings will have to have a fairly high level of isolation to allow the efficient use of heat-pumps.

3. The ratio of the heat produced, and the electricity consumed is called the Coefficient of Performance

It is debated whether the required level of isolation can be reached (technically and economically) for existing buildings. High electrification of the heating market without a high level of isolation will lead to a strong seasonality of demand in the electricity system.

The future electricity system of Germany will rely on renewable generation and to guaranty supply, dispatchable power generation is required. Current studies see a need for 60 GW_el (and even more) in the form of gas fired power plants based on methane or hydrogen. If CO_2-neutral methane would be available to cover future heating demand, this would be a rather cost-efficient solution since the infrastructure and appliances at the customers could be used. A switch to hydrogen in the distribution grids is also option, but it would require retrofitting of heating installations.

Import of Hydrogen to Germany

While Germany will continue to import energy in the future, the mix of energy carriers that finds its way to the German market depends on prices and availability of different carriers. As illustrated in figure 7, different studies foresee different constellations with regards to the import of hydrogen and other PtX fuels. AGORA (2020) and Fraunhofer (2020) envisage a need to import around 150 TWh of renewable hydrogen in 2050. According to the dena (2018) study (scenarios EL95 and TM95), significant volumes of energy will be imported in the

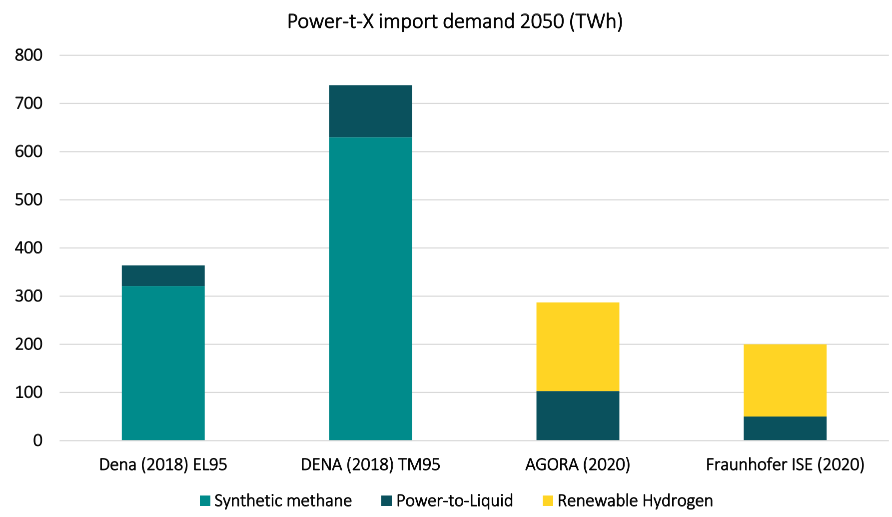

Figure 7: Scenarios for PtX import demand in Germany in 2050. Dena, 2018); (AGORA, 2020); (Fraunhofer ISE, 2020).

form of power-to-liquid and synthetic methane rather than hydrogen, in 2050. In these studies, the assumption is that the required hydrogen for the German market is produced locally.

More recent studies work under the assumption that Germany will be connected – via pipelines – to a larger European hydrogen market. This enables cost-effective import and use of hydrogen also for electricity generation, which is not as commonly accepted. In 2021, two studies will be published that will probably also be relevant for a scenario-based modelling variant in the upcoming Netzentwicklungsplan Gas 2022-2032. There will be an "update" of the dena Leitstudie and the Netzstudie III will be published. The Ministry of Economic Affairs is working on the concept of a System Development Plan (SDP), which in the end should bring the network development plans for gas and electricity closer together. The Netzstudie III will be one element of a pilot of the planned SDP process. Preliminary results of the dena Leitstudie II and Netzstudie III studies indicate significant need for import of hydrogen.

In the National Hydrogen Strategy, only about 14 TWh/a of the required hydrogen production is expected to be realized in Germany by 2030. The ambition with regards to hydrogen uptake (90-110 TWh) according to the National Hydrogen Strategy leaves therefore a rather significant hydrogen import demand.

Hydrogen infrastructure planning in Germany

To unlock the potential for import of hydrogen and other PtX fuels to Germany, planning of infrastructure that enable transportation of these energy carriers will be essential for realizing the ambitions laid out in Germany's National Hydrogen Strategy. Since 2019, the Germans TSOs (organized in the FNB Gas association) have developed a vision for a German hydrogen grid (green lines in figure 8), which was published in January 2020. The proposed grid is largely based on repurposing of existing gas infrastructure. But this vision is not a plan. In the network development plan in 2020 (Netzentwicklungsplan Gas 2020-2030), the German TSOs have developed a plan for a concrete hydrogen grid till 2030 (blue lines in figure 8). The plan is based on hydrogen demand collected in a market survey. The plan includes all technical measures, that are necessary to realize the hydrogen grid and to keep available the existing capacity for the transport of methane. The hydrogen grid till 2030 would reach relevant demand centers in the North/West of Germany including the Ruhr area and the cities of Bremen and Hamburg. Hamburg can be connected to the hydrogen grid already in 2025.

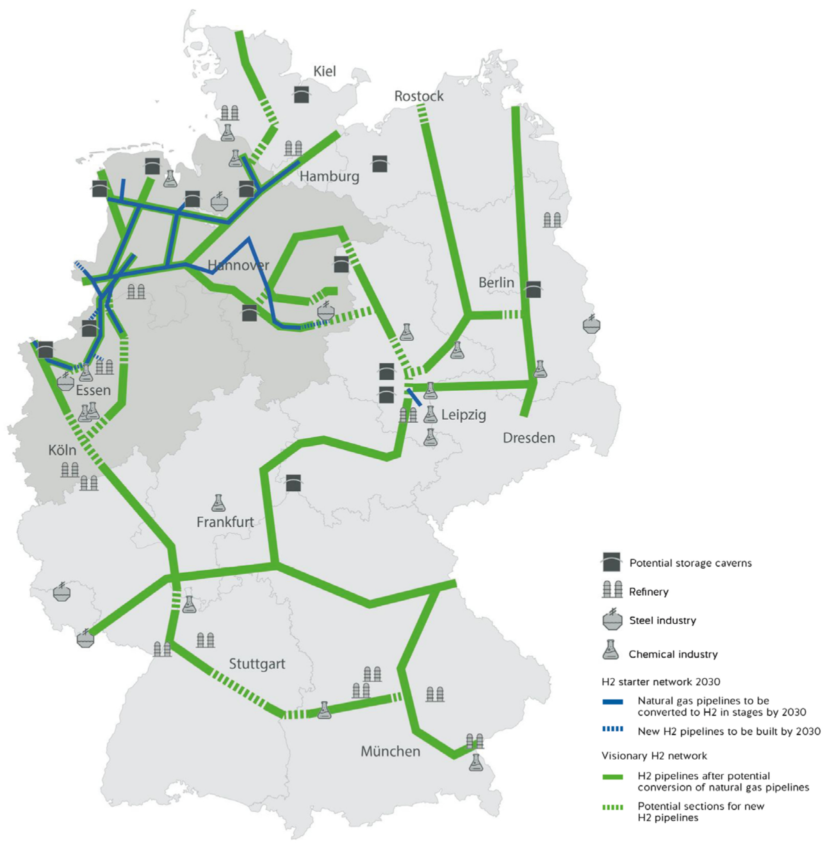

Figure 8: H_2 Startnetz (FNB Gas 1, 2020).

6. Technical aspects of hydrogen transport via pipeline

Transportation of hydrogen via pipeline has been in operation for more than 80 years in both Europe and the United States. Most of these hydrogen networks are private and located in industrial areas connecting consumption and production of hydrogen between a few companies. Examples of hydrogen networks in Germany can be found in the Ruhr district and the eastern "chemical triangle".

Europe has a very high safety record for natural gas transportation by pipeline, and it is important to stay on that path, looking into a future of potentially transporting large amounts of hydrogen. Gas-TSOs are in the middle of the process of investigating the technical feasibility of retrofitting and repurposing gas infrastructure for transport of hydrogen. In 2018, the first gas pipeline owned by Gasunie in the Netherlands has been repurposed for transportation of hydrogen. The concerned pipeline is 12 km long and used commercially for transporting more than four kilotons of hydrogen per year (Gasunie, 2018). Energinet has just launched a technical study to investigate the feasibility of repurposing a specific pipeline in Denmark to obtain knowledge of the operational capability for hydrogen transport and the costs of repurposing compared to building a new pipeline.

In Germany, the DVGW (Deutscher Verein des Gas- und Wasserfaches) is responsible for the development of technical regulations for the construction and operation of gas pipelines. DVGW is working to expand the existing regulations to include high concentrations of hydrogen blending into the methane system and transportation of pure hydrogen (new-built and repurposed gas pipelines).

The German TSOs are members of the DVGW and the input to the DVGW process is therefore based on expert knowledge from TSOs, the DVGW and external experts. Several concrete (i.e., projects focusing on the conversion of a concrete pipeline segment) studies of TSOs went into the process. All rules developed by the DVGW are going through a broad consultation and acceptance process. The work on the German rulebooks is not yet completed, but some results have been finalized and presented in a preliminary code of practice document ("DVGW G409").

Main assumptions for the technical analysis

This section focuses on the key technical assumptions and associated background information. A complete list of assumptions is provided in Appendix 1.

Re-use of the existing pipeline system

This study is working under the assumption that existing pipelines can be repurposed and that the current maximum operational pressure can be applied.

There is yet very little experience on repurposing of natural gas pipelines and the technical feasibility will generally have to be assessed on a case-by-case. It is expected that assets such as line valve stations, gas metering and control stations and pig installations will have to be adapted for hydrogen. In this study we estimate that the cost of repurposing pipelines can be covered by a flat rate cost of 25 % of a similar newly built pipeline.

A roadmap for repurposing of gas pipelines is described in the new DVGW G409 code of practice. To obtain approval to operate a pipeline with hydrogen, the suitability of the material to hydrogen must be proven. This includes, in particular, carrying out fracture mechanics analysis since hydrogen can influence the ductility of steel. The effect of this can increase the crack growth in the hydrogen environment. While crack growth in pipelines operated with natural gas is usually negligible, it must be considered for operation of hydrogen pipelines.

Capacity of a hydrogen pipeline and velocity of the hydrogen flow

In the network simulations we did not set a limit for the pressure variation or hydrogen flow velocities, therefore on certain pipeline sections the analysis resulted in velocities above current practice for natural gas pipelines.

The pressure drops over a pipeline trajectory depends on the absolute pressure, the flow rate, but also the type of gas. With a given pressure drop between two points, a much higher hydrogen volume flow can be realized compared to methane flow with the same pressure drop. Because of the reduced pressure loss of hydrogen in a pipeline you see much higher hydrogen flow velocities in a hydrogen pipeline compared to a methane pipeline operated with the “same pressure conditions”. The result in the end is, that a possible energy transport via hydrogen over a system is in the magnitude ~80 % of a methane system even though the calorific value of hydrogen is smaller by a factor of 3-4.

The effect of allowable pressure variation and velocities in pipelines must be further investigated with respect to noise, oscillation or erosion issues and the risk for possibly decreasing the pipeline integrity. It is therefore deemed relevant to perform a technical assessment of the feasible velocity levels in a hydrogen network and perform simulations on how it impacts transport volumes and investments costs in future studies.

Compression of hydrogen

The density of hydrogen is much lower than the density of methane. Because of this, the commonly used radial compressors designed for methane cannot be re-used for compression of hydrogen. In this study we assume that compressor stations cannot be repurposed for hydrogen and therefore will have to be built from new.

Since the calorific value of hydrogen is smaller by a factor of 3-4 compared to methane, the compression power required for the energy transport (MWh/h) via hydrogen is a factor 3-4 higher compared to the transport of methane. Therefore, the CAPEX and OPEX costs (per MW energy flow) for the compression of hydrogen will be 3-4 higher than for methane in the same pipeline setup.

7. Technical analysis

This case study provides an example of a how a network could be designed considering access to demand and supply and the possibility for repurposing existing pipelines.

Esbjerg and Holstebro in Denmark are identified as potential starting points for large-scale hydrogen transport. Partly because both cities are located near the west coast of Jutland, close to the North Sea where most of the offshore wind will be developed and since the land area between Esbjerg and Holstebro has significant potential for large scale solar PV development.

Starting in Esbjerg could be advantageous, partly since the city is the central hub for Denmark's oil and gas activities and increasingly growing into a center for offshore wind activities. The resources and competences in Esbjerg could be exploited for PtX production and associated infrastructure. Also, hydrogen infrastructure could potentially enhance the business case of ammonia production in Esbjerg while excess heat from PtX production could be reused in the extensive district heating network in the city. Furthermore, by adding a ~30 km eastern connection from Egtved to Fredericia, the refinery in Fredericia could switch from its current use of fossil-based hydrogen to renewable hydrogen from wind and solar.

The advantage of starting in Holstebro is that the transportation system would be close to geological salt caverns for hydrogen storage north of Viborg in Denmark. It remains uncertain whether Holstebro or Esbjerg will become entry points for large-scale transport of hydrogen and therefore both developments are analysed in this case study.

The routing from Esbjerg will consist of approximately 50 km new west-east pipeline towards Egtved, from where the pipeline will be connected to one of the existing gas transmission pipelines towards Ellund (the Danish-German border station). The routing from Holstebro will follow a similar concept, with a west-east routing until it reaches the existing north-south bound pipeline. The additional length of pipeline required to connect to Holstebro is around 100 km. It is assumed that the new pipeline will follow the existing pipeline trace to Egtved. From Egtved to Ellund the hydrogen

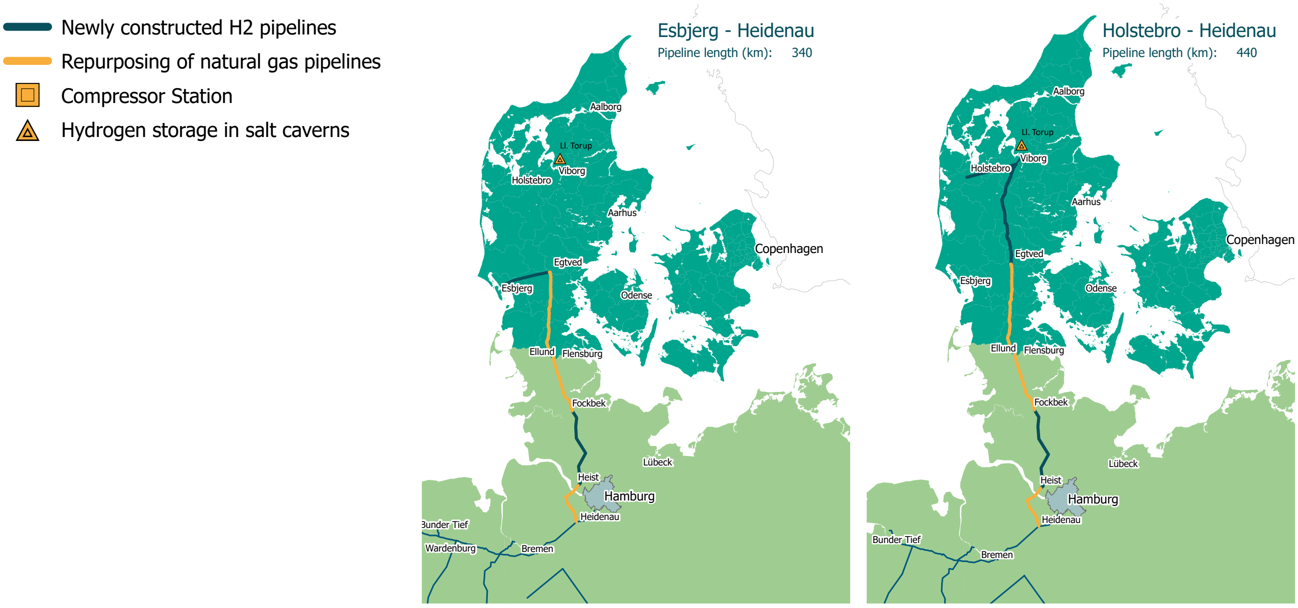

Figure 9-10: Two alternative hydrogen routes from Denmark to Germany with starting points in Esbjerg and Holstebro.

will be transported in a 30" repurposed pipeline. New pipelines are assumed 36", while the repurposed one is 30", and all with design pressures of 80 bar(g).

On the German side Ellund is connected to Heidenau south west of Hamburg. Heidenau has been chosen as the end point as it provides a connection to the German hydrogen backbone system as planned in the network development plan 2020 for 2030 with a potential link to demand centers in the north and west of Germany including the Ruhr area. Hamburg can be connected to the hydrogen grid already in 2025.

From Ellund to Fockbek and from Heist to Heidenau currently a high-pressure parallel pipeline system is used for methane transport. The operating pressure is 84 bar(g) in the northern section and 70 bar(g) in the southern section. In the section from Fockbek to Heist the transmission system consists of a single pipeline. The 36" pipeline from Ellund to Fockbek and the 24" inch pipeline from Heist to Heidenau are available for hydrogen transport while the remaining methane system can sufficiently support demand for transport of methane. To connect these two pipelines a new 36" pipeline from Fockbek to Heist (in parallel to the existing methane pipeline) is needed.

Route	Km	% repurposed
Esbjerg – Heidenau (Hamburg area)	340	62
Holstebro-Heidenau (Hamburg area)	440	48

Table 2: Pipeline length and ratio of repurposed pipelines for the two pipeline routes between Denmark and Germany.

Repurposing of existing gas pipelines constitute between 48 and 62 % of the total length of the route depending on whether Esbjerg or Holstebro are entry points (see table 2).

Transport capacities

Several scenarios have been identified and analyzed to assess the possible transport capacities and indicative investment costs. For the capacity calculations, a series of physical steady-state flow simulations in a point-to-point set-up have been conducted. The compressor power needed is calculated to compensate for the pipeline pressure drop. The simulations provide indicative results for the possible transport capacities based on the set assumptions. The high-level assumptions are chosen based on our current understanding of a required design of a hydrogen system.

Esbjerg-Heidenau (Hamburg area)

For the Esbjerg-Heidenau routing the result of our analysis is based on three scenarios that can be seen also as outlining possible future expansion steps. Scenario 1 is analyzing the maximum capacity without any line compression, while scenario 2 is analyzing the maximum capacity with a compression station in Egtved. For both scenarios an inlet pressure from hydrogen production is assumed at 35 bar(g) assuming pressurized electrolysis. The third scenario assumes an inlet pressure of 70 bar(g) in Esbjerg, which allows "to move" the compressor station further downstream to Ellund.

The envisaged hydrogen compressor stations in either Egtved or Ellund are located at the same locations as the current natural gas compressor stations. There could be advantages for these locations because of the synergies with the current maintenance base there and the assumption that they will be connection points to the repurposed pipeline. Due to different pressure regimes in Denmark and Germany, the exit pressure from the compressor stations is set at 70 bar(g) for Egtved and 84 bar(g) for Ellund.

The assumptions and results of the three scenarios are presented in table 3. For the Esbjerg-Heidenau routing the resulting maximum transport capacity is between 2.5-8.6 GWh/h. When initially no compressor station is used, the maximum capacity is 2.5 GWh/h. By installing a compressor station in Egtved, the maximum capacity can be increased to about 6.3 GWh/h. With a higher inlet pressure and a compressor station at Ellund the maximum capacity can be up to 8.6 GWh/h. In this scenario, the exit pressure in Heidenau is raised to 30 bar(g). The higher capacity in scenario 3 is due to a higher inlet pressure in Esbjerg combined with compressor station in Ellund that can make use of the higher design pressure (84 bar(g)) of the pipeline system in Germany.

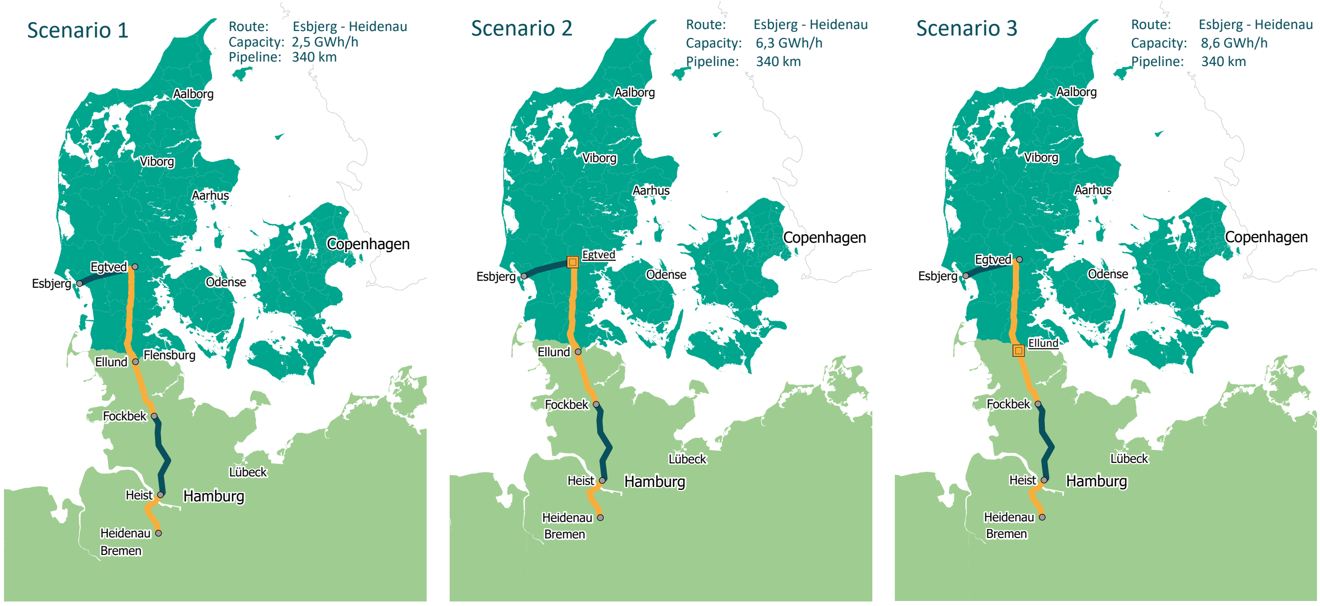

Figure 11-13: Transport capacities and compressor configurations for scenarios 1-3.

The three scenarios show a possible development starting with relatively low capacity to a fully developed system transporting up to 8,6 GWh/h. Designing a scalable pipeline system that can transport lower capacities in a start-up phase could be a cost-effective enabler for the development of a hydrogen economy.

Naturally, the capacity could be even higher, if a larger pipeline diameter for the newly built parts is used. Other aspects, such as the location of compressor stations and renewable energy production profiles could be taken into consideration to optimize the design of the overall infrastructure. Since the operational cost of compression is relatively costly compared to the overall system, optimizing the design of the network with larger pipelines to reduce the need for compression should be analyzed further.

Table 3 shows how the three scenarios for transporting hydrogen from Esbjerg to Heidenau perform with regards to transport capacities taken into consideration inlet pressures and compressors station configurations.

Scenario	DK P_{Entry} [bar(g)]	DK Entry Point	CS Egtved P_{Inlet} [bar(g)]	CS Ellund P_{Inlet} [bar(g)]	Heidenau P_{Exit} [bar(g)]	Capacity [GWh/h]
1	35	Esbjerg	-	-	20	2.5
2	35	Esbjerg	31	-	20	6.3
3	70	Esbjerg	-	33	30	8.6

Table 3: Capacity simulation key assumptions and results for a scalable pipeline network between Esbjerg and Heidenau.

A clear bottleneck of the network is the connection from Heist to Heidenau. The existing pipeline of 24" is used in this section since it is crossing the river Elbe, which is a rather wide river downstream of Hamburg. The small diameter (24'') between Heist and Heidenau results in high maximum velocities (up to 70 m/s) on this section of the route compared to what is considered feasible for methane transport. An optimization (e.g. building a loop south of the Elbe) on this section could be explored. Figure 14 shows the velocity profile and corresponding pressure drops of scenario 2.

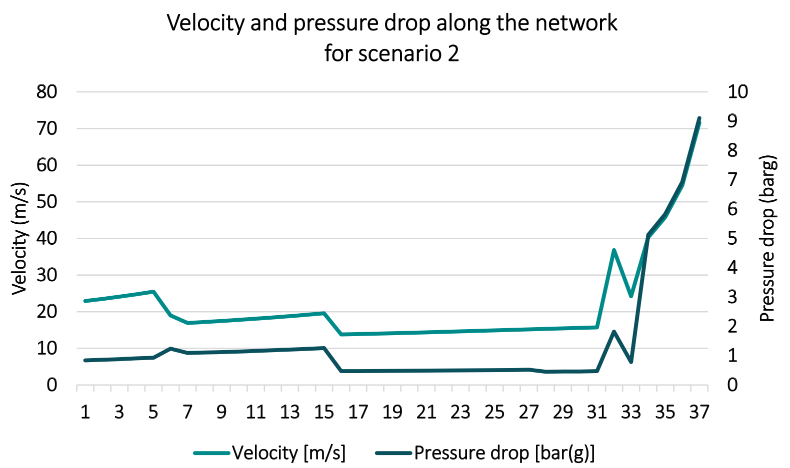

Figure 14: Illustration of the resulting pipeline velocity of scenario 2 (Esbjerg-Heidenau with compressor station in Egtved).

Holstebro-Heidenau (Hamburg area)

We also analyzed an alternative route from Holstebro to Heidenau with inlet pressure of 70 bar(g), 30 bar(g) exit pressure and two compressor stations, in Egtved and Ellund. Two compressor stations are needed for keeping the capacity at 8.6 GWh/h at the exit point in Heidenau. Similarly to the Esbjerg-Heidenau connection, this route could also be scalable starting with no compressor stations and lower volumes. The same bottleneck with regards to velocities and pressure drops between Heist and Heidenau also exists in this scenario.

Access to storage in this scenario could help balance fluctuating renewable production patterns and generate stable supply for national demand and export to Germany. It is however beyond the scope of this paper to study in detail how storage can help balance the variability between demand and supply and consequently impact the design of the pipeline network.

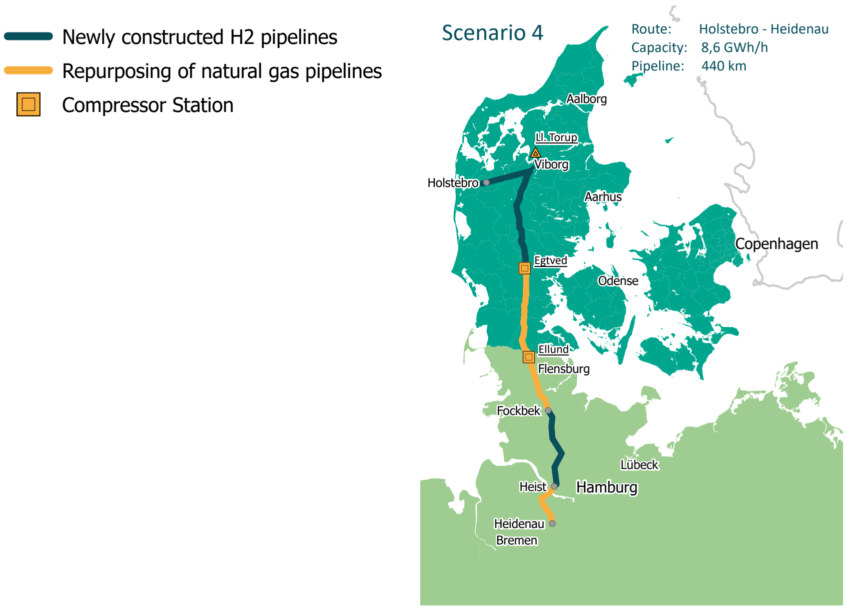

Figure 15: Transport capacities and compressor configurations for scenarios 1-3.

Scenario	DK P_{Entry} [bar(g)]	DK Entry Point	CS Egtved P_{Inlet} [bar(g)]	CS Ellund P_{Inlet} [bar(g)]	Heidenau P_{Exit} [bar(g)]	Capacity [GWh/h]
4	70	Holstebro	56	41.4	30	8.6

Table 4: Capacity simulation results for scenario 4 with an alternative route between Holstebro and Heidenau.

Indicative costs

We have provided indicative investment costs for scenario 1, 2, 3 and 4 as shown in table 5. Costs estimates for pipelines are based on available public information from the European Hydrogen Backbone (EHB) study (Guidehouse, 2020) and (FNB Gas 2, 2020). The estimates are based on EHB medium cost estimate, which is in line with the cost estimates from the FNB Network Development Plan (FNB GAS 2, 2020). Based on our current knowledge we therefore consider it to be best estimates. There is however a relatively high uncertainty on the cost estimate due to the so-far limited knowledge on investment costs for large-scale hydrogen pipelines.

The CAPEX for compression is calculated linearly from the power required to compress the gas. Further details of the compressor stations (e.g. necessary compression steps) are not taken into account and should be studied further. Operational costs depend on the usage of the pipeline system, i.e., the capacity bookings and the offtake. We do not consider these aspects in the study and for matter of simplicity we assume compressor stations run 24/7. As we did not include an analysis of load factors for pipeline operation in the study, operational costs are indicative and highly conservative.

The investment costs of transporting only 2.5 GWh/h (scenario 1) is estimated to be 390 MEUR. For a full development of the network where maximum capacity is increased to 8.6 GWh/h (scenario 3), the addition of a compressor station in Ellund brings the total costs up to 670 MEUR. This shows that the costs of compressor stations can constitute up to 40 % of the total investment costs.

For scenario 4 (Holstebro-Heidenau), investment costs amount to about 875 MEUR because this route has 100 km additional new built pipeline compared to Esbjerg-Heidenau. Although the longer route requires two compression stages – in both Egtved and Ellund – we note that the costs of compression in scenario 4 is lower than in scenario 3. This is caused by non-linear effects of the high pressure drop in the pipeline due to high velocity at low pressure, which results in higher energy losses in scenario 3. Contrastingly, scenario 4 has lower compression ratios per compressor station and the total power input required for compression is therefore reduced. Since the CAPEX compression costs are assumed only to be proportional to the total energy input, the compression cost for scenario 3 is higher than for scenario 4.

The investment cost for repurposing of pipelines is assumed to be 25 % of the cost for building new pipelines. The cost associated with providing the pipeline inlet pressure at production location of either 35 bar(g) (in scenario 1 and 2) or 70 bar(g) (in scenario 3 and 4) are excluded in the investment estimates. For scenario 1, 2 and 3 (Esbjerg-Heidenau), 48 % of existing pipelines are repurposed causing savings on investment costs for the pipeline of 320 MEUR compared to if the entire network were to be built from new.

Scenario	1	2	3	4
Capacity [GWh/h]	2,5	6,1	8,6	8,6
CAPEX Pipeline [MEUR]	390	390	390	610
CAPEX Compression [MEUR]	0	170	280	265
Total CAPEX [MEUR]	390	560	670	875
Max OPEX (Compression only) [MEUR/y]	0	60	100	95

Table 5: Indicative investment and operational costs for scenario 1-4. Costs are rounded to nearest five. See also appendix 2.

Comparison to other means of hydrogen transport

Pipeline transportation can be compared to other means of hydrogen transportation, such as ships or trucks. We find that transport of hydrogen in pipelines for the volumes and distances assumed in this study is more feasible – both from a logistical and cost perspective.

There is very little experience with transport of liquefied hydrogen via ships. Only one operational ship for transportation of hydrogen exists worldwide. Transportation of hydrogen by ship will generally take place in the form of liquefied hydrogen or ammonia and both cases result in significant energy losses from the conversion processes. According to the IEA (2020), transporting of hydrogen via ships compared to pipelines is only economical for distances over 1.500 km hence ship transport would not be feasible for the distances and volumes analyzed in this study.

There are also logistical challenges associated with transport of hydrogen via ships. Assuming hydrogen were transported from the port of Esbjerg to the port of Hamburg via ship, it would require a 160.000 m3-sized tank ship carrying about 11.000 tons of liquefied hydrogen on each trip (Al-breiki & Bicer, 2020). To deliver the same amount of capacity as we assume for scenario 1 (2,5 GWh/h) in a ship of this size, a new delivery would need to arrive in Hamburg every 5 days. If the same capacity was transported in trucks from Esbjerg to Heidenau, it would require 16 trucks every hour assuming each truck carries 4 tons of liquified hydrogen. If we instead assume that the hydrogen is compressed, hundreds of trucks would be needed (Ogden, 2004).

From a cost perspective, transporting of liquefied hydrogen via trucks does not seem feasible, particularly for the scenarios with higher transport capacities as illustrated in figure 16. It should be noted that comparing yearly operational costs of truck transport with CAPEX and OPEX calculations for the pipeline transport have its limitations. However, we think it is worth observing that in just two years, the cost of trucks surpasses the investments cost for the pipeline for scenario 1 (390 MEUR vs. 202 MEUR per year). For scenario 3 the capacity of the pipeline is roughly three times higher than scenario 1 and consequently the yearly cost by truck of 714 MEUR per year is similar to the investment cost of both the pipeline and the compressors for scenario 3. In this scenario there is a high operational cost for the compressor station, why the maximum operational yearly costs amount to 10-15 % at full capacity compared to the cost of truck transport.

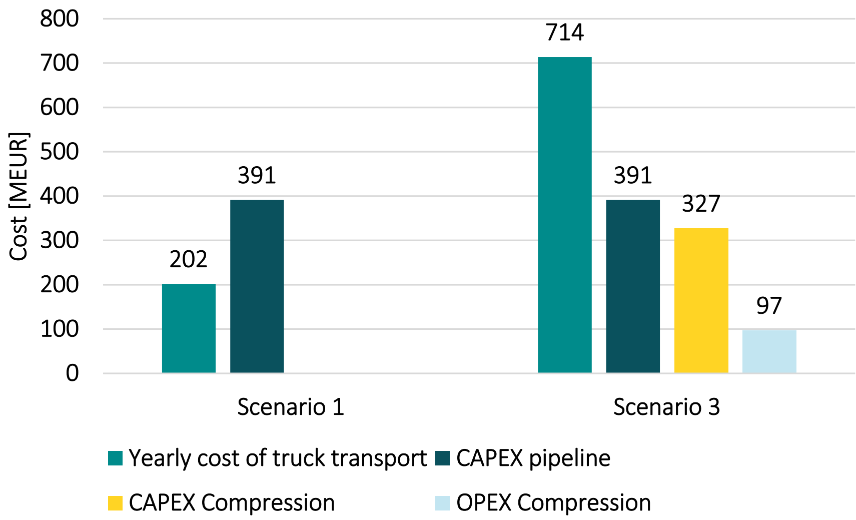

Figure 16: Yearly cost of operating hydrogen trucks to transport the required quantities of hydrogen in scenario 1 and 3 compared to the CAPEX of pipeline, compressor stations and the yearly OPEX of running the compression in scenario 3. Yearly truck transport is calculated using the Danish Energy Agency Technology Catalogue (DEA 2, 2020).

8. Conclusion

This study provides an example of how a hydrogen network could be designed in phases starting with no compressors and eventually upgraded to accommodate for increasing demand for transport of hydrogen. The proposed network is largely based on repurposing of existing gas infrastructure, which reduces the overall costs of the system. Compressors constitute a large cost parameter, hence building a network without compressors in a start-up phase could reduce up-front investment costs for the infrastructure. The design of the network merits further analysis looking into renewable production profiles and connection to long-term storage, among other things.

Whether the entry point of hydrogen into a potential hydrogen transmission network starts in Esbjerg or Holstebro depends, among other things, on the cost of integrating renewables into the wider energy system in Denmark taking into consideration the consequences for the power grid with respect to congestion. The national demand and access to storage will also influence the optimal locations for hydrogen production.

From a cost perspective, we find that a transport corridor between Denmark and Germany can be realized rather quickly. But the timing of realizing a network depends on the complexity of the transportation system, the share of the pipeline that is repurposed from methane to hydrogen, the condition of the pipeline that is repurposed, and the number of compressor stations needed. However, from a financing perspective, clear market signals and regulation will need to be in place before it is possible to move forward and make final investment decisions.

Since this study foresees transport of renewable hydrogen, the economic feasibility of the network not only depends on the potential in terms of market volume, but also the competitiveness of renewable hydrogen vis-à-vis fossil-based hydrogen. Factors influencing market uptake for renewable hydrogen is not covered in the study.

In summary, the study finds that

1. It can be done - A hydrogen connection between Denmark and Germany can be realized rather quickly. The development depends on the needs in the hydrogen market.
2. It can be done flexibly - The design of the hydrogen connection is scalable. In the initial stages, significant capacity can already be made available through a network consisting of pipelines only (saving on compression in the initial stages). Depending on the developments in hydrogen supply and demand, the capacity of the pipelines can be increased further by installing compression power.

3. It can be done efficiently - Repurposing of existing pipelines reduces costs and should be considered where possible.

4. Clear market signals are needed – while we have provided an exemplified design of a hydrogen network, Energinet and Gasunie now invite stakeholders to get in contact in order to better understand the actual demand for hydrogen transport between Denmark and Germany.

9. Future work and dialogue with the market

At the EU-level, work has been started to revise different regulatory frameworks to prepare for a liquid hydrogen market that is primarily based on renewable hydrogen and supported by cross-border infrastructure. This includes the revision of the RED II (Renewable Energy) directive, the TEN-E (Trans-European Networks for Energy) Directive as well as the revision of rules for gas markets in the EU. Eventually national implementation of hydrogen related regulation will also impact the readiness of a hydrogen market and the ability to begin the work of infrastructure development.

In the planning of the Ten-Year-Network-Development Plan (TYNDP) for 2022, ENTSOG has started the process of developing a methodology for collecting of input on hydrogen demand and production. Projects that are included in the TYNDP are expected to have a better chance for getting on future PCI (Projects of common interest) lists.

Under the coordination of the FNB Gas, German Gas-TSOs have already completed a market survey on demand and supply for hydrogen as a base for the Network Development Plan for 2022.

We hope that this study can serve as inspiration for the up-coming TYNDP process by generating further market dialogue and increase transparency on the potential need for a hydrogen network between Denmark and Germany as well as other possible cross-border connections.

For the technical aspects of hydrogen pipeline transportation further studies are required to better understand which pipelines are fit for repurposing, how to modify them and associated assets, (like valve stations) and how to optimally design the system taking into account location of compressor stations, among other things. Operational issues with regards to safety also have to be studied further.

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Appendix 1: Assumptions for the design of the network

Assumptions related to the design of the network are listed below.

Hydrogen offtake	**Hydrogen offtake is only assumed at Exit in Heidenau.**
Medium being transported share (%) in the network	The network is assumed to transport 100% pure hydrogen.
Capacity simulations	The capacity simulations are static and no limitation from pressure fluctuation is assumed.
Inlet pressure	The hydrogen is assumed available at an inlet pressure to pipeline of either 35 bar(g) or 70 bar(g).
Exit pressure	The exit pressure at Heidenau is either 20 bar(g) or 30 bar(g).
Repurposing of existing gas pipelines	Repurposing of a pipeline is assumed possible where there are parallel pipelines today (Ellund-Egtved, Ellund-Fockbeck and Heist-Heidenau).
Design pressures and pipeline diameters	New-built pipelines are assumed 36” with design pressures of 80 and 84 in Denmark and Germany, respectively.
Compressor stations	Repurposing of compressor stations for natural gas is not assumed to be possible.

Appendix 2: Assumptions for calculation of costs

We rely on available public information from the European Hydrogen Backbone Vision from July 2020 (Guidehouse, 2020) and the draft FNB Gas Network Development Plan (FNB Gas 2) from July 2020 for costs assumptions. Assumptions are listed below:

- The cost of pipelines is based on EHB medium cost estimates
- The costs of repurposing gas pipelines are assumed to be 25 % (same as EHB) of new-built pipelines
- The costs of compressors stations are based on FNB NDP
- The operational cost of compression is assumed to be 2 % of CAPEX for compression + the costs of power usage.
- The cost estimates do not include cost for hydrogen pressurization at pipeline inlet
- The cost estimates do not include cost for requisition of the methane pipelines
- Power price is 0,1142 EUR/kWh
- Unit prices are in 2020 annual prices

Pipeline configuration and cost break-down for Esbjerg-Heidenau (scenario 1-3)

Route	Distance [KM]	Diameter/ pressure	CAPEX (Best) [MEUR]
Esbjerg-Egtved	50	36”/80 bar(g)	110
Egtved-Ellund	100	30”/80 bar(g)	49
Ellund-Fockbeck	63	36”/84 bar(g)	35
Fockbeck-Heist	79	36”/84 bar(g)	174
Heist-Heidenau	49	24”/84 bar(g)	24
Total	341		391

Pipeline configuration and cost break-down for Holstebro-Heidenau (scenario 4)

Route	Distance	Type	CAPEX (best) [MEUR]
Holstebro-Egtved (New built)	150	36"/80 bar(g)	330
Egtved-Ellund (Repurposed)	100	30"/80 bar(g)	49
Ellund-Fockbeck (Repurposed)	63	36"/84 bar(g)	35
Fockbeck-Heist (New built)	79	36"/84 bar(g)	174
Heist-Heidenau (Repurposed)	49	24"/84 bar(g)	24
Total	441		611

Compressor configurations and cost-break down (scenario 2-4)

	Scenario 2 (Compressor station in Egtved)	Scenario 3 (Compressor station in Ellund)	Scenario 4 (Compressor stations in Egtved and Ellund)
Compression power[MW]	54,2	89,9	85,5
Compression CAPEX [M€]	169,1	280,7	266,9
Compression OPEX [M€/year]	58,7	97,4	92,6